

Study Guide for the SPE Petroleum Engineering Certification Examination



Society of Petroleum Engineers

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FOREWORD

This Study Guide has been prepared to aid petroleum professionals studying for the SPE Petroleum Engineering Certification Programme. The material includes a full sample exam that can be used to help prepare for the certification exam.

SPE certification has been discussed both within and outside the society for many years. Many petroleum engineers have not been required to be certified until the past few decades. The environmental and consumer era of the past few decades have given the public greater awareness of pollution, energy, and the need for more industry professionalism.

In 2004, The Society of Petroleum Engineers established a pilot program to provide a society-sponsored Petroleum Engineering Certification Programme at the request of the membership.

ACKNOWLEDGMENTS

The SPE Petroleum Professional Certification Subcommittee gratefully acknowledges the contributions of the authors of *A Guide to Professional Engineering Licensure* and the SPE U.S. Engineering Registration Subcommittee and SPE Engineering Professionalism Committee for permission to use material from that book. The Subcommittee also recognizes past and present Committee members for their efforts in preparing this guide, with thanks to Gus Mistrot, P.E., Bing Wines, P.E., Charles Haynes, P.E., and William McCain, P.E., for their contributions to earlier editions of *A Guide to Professional Licensure for Petroleum Engineers*. Special thanks to Cindy Reece, P.E., for her contributions in revising this edition to reflect significant changes in the exam format.

SECTION 1

SPE Petroleum Engineering Certification Programme Exam

The certification examination is given open-book style in two 4-hour sessions. You will be asked to work 100 multiple-choice problems--50 in the morning and 50 in the afternoon. Your score will be based on the number of problems you solve correctly..

Example Items To Take to the Examination*

1. Wristwatch.
2. Straight edge, 45° triangle, 30°/60° triangle, French curve.
3. Any battery-operated, charged, non-printing, non-communicating, silent calculator (one you are familiar with) and extra battery pack. Do not count on available electrical socket. Calculators may not be programmable.
4. Reference books, but not unbound material or handwritten notes.
5. This study guide.

Writing instruments are supplied onsite, so do not bring pens, pencils, or erasers.

Calculator Policy

You may not use a calculator that communicates with other devices or that may otherwise compromise the security of the examination. Of particular concern is the ability to type in text, store it in memory, and then communicate via wireless or cable connections to another calculator, personal computer, printer, or other electronic device. This policy is strictly enforced. A list of approved calculators is provided annually.

Along with cell phones and other electronic devices, any unapproved calculators will be confiscated by the proctor. If an unapproved calculator is found in your possession after the exam begins, you will be dismissed from the exam room and your exam will not be scored. Clearing the memories of prohibited calculators for use in examination room is not feasible due to exam sites with a large number of examinees. There are two issues here related to security that include calculators that can communicate with other units during the exam and calculators used to store text that is taken from the room. Clearing the memory satisfies only one of those issues.

Textbooks and Reference Materials

Following are specific textbooks and handbooks that you should find helpful. The specific references that you should bring into the examination will depend upon your expertise. Only one or two references can be effectively utilized at one time, and from a logistic viewpoint, a maximum of 11 to 15 can be carried and efficiently reached and used.

This reference list is neither complete nor exclusive. Specific texts are listed because of their popularity at this time; consequently, they are being used as references by the Professional Engineers who are composing the problems. **Beginning in 2009, all exam problems will be written to reference the SPE Petroleum Engineering Handbook.** You may want to consider the use of the secondary reference listed as follows:

Drilling

Well Design, Drilling Operations, Drilling Hydraulics, Penetration Rates, Pore Pressures, Cementing Operations, Blowout Control, and Mud Systems

1. Adams, N.J. and Charrier, T.C.: *Drilling Engineering-A Complete Well Planning Approach*, Penn-Well Publishing Co., Tulsa (1985)
2. Bourgoyne, A.T. *et al.*: *Applied Drilling Engineering*, Textbook Series, SPE, Dallas (1986).
3. Cihyous, William, ed., *Standard Handbook of Petroleum and Natural Gas Engineering, Volume One*, Gulf Publishing Co., Austin, Texas (1996)
4. Any service company cementing handbook.

Casing, Tubing and Drillstring Design

1. All references listed above.
2. *Packer Calculations Handbook*, Baker Oil Tools Group (1971).
3. "Packer Completion Techniques" (incl. Engineer Tables), Dresser Industries Inc. (1978).
4. *Casing and Tubing: Technical Data, Dimensions, and Performance Properties*, Lone Star Steel (1984).
5. *API Bulletin 5C2: Performance Properties of Casing, Tubing, and Drillpipe*, American Petroleum Inst., Dallas (1984).

Formation Evaluation

Well Testing

1. Earlougher, Robert C. Jr.: *Advances in Well Test Analysis*, Monograph Series, SPE, Dallas (1977).
2. Matthews, C.S. and Russell, D. G.: *Pressure Buildup and Flow Tests in Wells*, Monograph Series, SPE, Dallas (1967).
3. Lee, W.J.: *Well Testing*, Textbook Series, SPE, Dallas (1982).
4. Horne, R.N.: *Modern Well Test Analysis*, second edition, Petroway Inc., Palo Alto, California (1995).

Openhole Logging

1. Bassiouni, Zaki: *Theory, Measurement, and Interpretation of Well Logs*, Textbook Series, SPE (1994), Dallas.
2. *Log Interpretation Principles/Application*, Schlumberger Educational Services (1989).
3. Any service company chart book.

Production Operations

Production Facilities

1. *Engineering Data Book*, 10th edition, Gas Processors Suppliers Association, Tulsa (1987), Sections 7, 8, 13, 20.
2. Cambell, J.M. and Maddox, R.N., *Gas Conditioning and Processing, Vol. II*, Norman, Oklahoma (1970).

3. Economides, M., Hill, A.D., and Ehlig-Economides, C.: *Petroleum Production Systems*, Prentice Hall (1994).
4. Allen, T.O., and Roberts, A.P.: *Production Operations Vol. 1: Well Completions, Workover & Stimulation*, fourth edition, OGCI (1993).
5. Allen, T.O. and Roberts, A.P.: *Production Operations Vol. 2: Well Completions, Workover & Stimulation*, fourth edition, OGCI (1993).

Artificial Lift

1. *API Recommended Practice RP-11U: Sizing and Selection of Submersible Pump Installations*, American Petroleum Inst., Dallas (1986).
2. *API Recommended Practice RP-11L: Design Calculations for Sucker Rod Pumping Systems*, American Petroleum Inst., Dallas (1977).
3. *Handbook for Electrical Submersible Pumping Systems*, fourth edition, Centrilift Inc., Claremore, Oklahoma (1987).
4. Brown, K.: *Technology of Artificial Lift, Vol. 2a*, PennWell Publishing Co., Tulsa (1980).
5. *Submersible Pump Handbook*, Centrilift, 4th Edition (1987).

Production Scheduling/Well Performance/Nodal Analysis

1. Brown, K.: *Technology of Artificial Lift, Vol. 1 and Vol. 4*, PennWell Publishing Co., Tulsa (1984).
2. Slider, H.C.: *Worldwide Practical Petroleum Reservoir Engineering Methods*, PennWell Publishing Co., Tulsa (1985) Chapter 8.
3. *Engineering Data Book*, tenth edition, Gas Processors Suppliers Assn., Tulsa (1987).
4. Nind, T.E.W.E.W.: *Principles of Oil Well Production*, second edition, McGraw-Hill (1981).
5. *Production & Reservoir Systems Analysis, Sec. II*, Schlumberger.

Completions/Stimulations/Well Design

1. Gidley, J.L., *Recent Advances in Hydraulic Fracturing Monograph, Vol. 12*, SPE Richardson (1990).
2. Williams, et.al.: *Acidizing Fundamentals*, SPE Monograph No. 6, SPE.
3. Bourgoyne, A.T. Jr., Millheim, K.K., Chenevert, M.E., and Young, F.S. Jr.: *Applied Drilling Engineering Textbook Vol. 2*, SPE (1991).
4. Mitchell, Bill: *Advanced Oilwell Drilling Engineering Handbook*, tenth edition, Mitchell (1995).
5. *The FracBook Design/Data Manual and The Frac Book II Manual*, Halliburton.
6. *Packer Calculations Handbook*, Baker Packers.
7. Craft, Holden & Graves, *Drilling and Production*.

Economics

1. Jensen, Jerry L., Lake, Larry W., Corbett, Patrick W. M. and Goggin, David J.: *Statistics for Petroleum Engineering & Geoscience*, Elsevier (2000).

Production Logging

1. Hill, A.D., *Production Logging-Theoretical & Interpretive Elements Monograph, Vol. 14*, SPE (1990).
2. *Cased Hole Log Interpretation Principles*, Schlumberger (1989).

3. *Interpretive Methods of Production Well Logs*, Fourth Edition, Atlas Wireline Services.

Multidisciplined Interest/General Petroleum Engineering

1. Bradley, H.B., *Petroleum Engineering Handbook*, SPE (1992).
2. Mian, C.H.: *Petroleum Engineering Handbook for Practicing Engineers, Volume 2*.
3. *Cement Evaluation*, Atlas Wireline Services (1990).
4. *TechFacts Engineering Handbook*, Baker Oil Tools (1995).
5. *Halliburton Cementing Tables (Red Book)*, Halliburton Services (1981).
6. *Engineers Handbook*, Dowell-Schlumberger.
7. *Applied Hydraulics Manual*, Arrow Oil Tools.
8. *Technical Data Handbook*, Weatherford.
9. *Manual of Petroleum Measurement Standards*, API Standard 2530, API (1985).

Reservoir

General

1. Bradley, H.B.: *Petroleum Engineering Handbook*
2. Craft, B.C. and Hawkins, M.F.: *Applied Petroleum Reservoir Engineering*
3. Lee, J. and Wattenbarger, R.A.: *Gas Reservoir Engineering*
4. Dake, L.P.: *Fundamentals of Reservoir Engineering*
5. Ikoku, C.U.: *Natural Gas Production Engineering*

Economic Analysis

1. Thompson, R.S. and Wright, J.D.: *Oil Property Evaluation*
2. Newendorp, P. and Schuyler, J.: *Decision Analysis for Petroleum Exploration*, 2nd Edition

Reservoir Simulation

1. Mattox & Dalton: *Reservoir Simulation*

Fluid Properties and Analysis

1. McCain, W.D. Jr.: *The Properties of Petroleum Fluids*
2. Standing, M.B.: *Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems*
3. Ramagost, B.P. & Farshad, F.F.: *P/Z Abnormally Pressured Gas Reservoirs*, SPE 10125

Improved Recovery

1. Craig, F.F.: *The Reservoir Engineering Aspects of Waterflooding*
2. Stalkup, F.I.: *Miscible Displacement*
3. Prats, M.: *Thermal Recovery*

Well Production and Test Analysis

1. Earlougher, R. C. Jr.: *Advances in Well Test Analysis*, SPE Monograph Series Volume V.
2. Thompson, R.S. and Wright, J.D.: *Oil Property Evaluation*
3. Lee, W.J.: *Well Testing*
4. Fetkovich, M.J.: *Decline Curve Analysis Using Type Curves* (SPE)

5. Gentry, R.W.: *Decline Curve Analysis*, *JPT* (January 1972)

Coalbed Methane

1. Mavor, M.J., Nelson, C. R.: *Coalbed Reservoir Gas-In-Place Analysis*
2. Mavor, M.J. *et al*: *A Guide to Coalbed Methane Reservoir Engineering*

SECTION 2

Test Specifications for SPE Petroleum Engineering Certification Programme Examination in the Discipline of Petroleum Engineering (Effective January 2009)

Approximate
Percentage of
Examination
See Note 3.

I. Common Knowledge

- A. Principles of mathematics and the physical sciences.
- B. Petroleum engineering terminology.
- C. Relevant industry and company design standards.
- D. Relevant industry regulatory/environmental law.
- E. Industry and/or company-provided technical software/informational databases.
- F. Project management techniques (costing, scheduling, contracting, logistics).
- G. Geoscience principles (pore pressure, fracture gradients, wellbore stability, etc.).
- H. Risk analysis/contingency planning.
- I. Surveillance/optimization techniques.
- J. Economic principles.
- K. Multidisciplinary team participation.
- L. Professionalism, including ethics and due diligence.

II. Drilling

24%

- A. Tubulars.
- B. Cementing.
- C. Drilling fluids.
- D. Drillstring.
- E. Drilling mechanics.
- F. Hydraulics.
- G. Rig equipment capabilities.
- H. Directional/horizontal drilling.
- I. Wellheads.
- J. Well control/BOP.
- K. Solids control.
- L. Bits.

III. Completion, Production and Facilities

36%

- A. Proper lift mechanism selection given a set of well conditions.
- B. Sucker rod pumping systems.
- C. Gas lift, including intermitters, plunger lift, or gas lift valves.
- D. Downhole pumps including ESPs, progressive cavity pumps, or jet pumps.
- E. Well and completion systems including nodal analysis.
- F. Inflow performance curve analysis.
- G. Production logging.
- H. 2D sand fracture treatments.
- I. Matrix acid treatments.
- J. Tubing and downhole equipment.
- K. Plug and abandonment procedures.

- L. Remedial/recompletion operations (squeezing cementing, sand control, perforating, etc.).
- M. Selections of piping to accommodate flow rate, total pressure and pressure drop considerations.
- N. Compressor application and sizing parameters.
- O. On-site processing equipment including separators, heater treaters, or dehydrators.
- P. On-site storage vessels including piping, valves and venting.
- Q. Logging methods (wireline, MWD/LWD, open hole, cased hole).
- R. Well testing (wireline, production test, DST, well test analysis).
- S. Derivation of properties from formation evaluation data included lithology, mechanical rock properties, fluid properties and borehole dimension.
- T. Mechanical rock properties.

IV. Reservoir

40%

- A. Reservoir geoscience.
- B. Oil/gas reservoir performance.
- C. Methods to determine net pay.
- D. Phase behavior/reservoir fluids.
- E. Single/multiphase flow in porous media.
- F. Gravity/capillary and viscous forces.
- G. Methods for estimating reserves and recovery.
- H. Reservoir development techniques (patterns, rates, stimulation, etc.).
- I. Water/gas injection.
- J. Reservoir simulation techniques.
- K. Physical measurements (e.g., acoustic, nuclear, electrical).
- L. Lithology.
- M. Fluid properties.
- N. Coring (SWC, full hole core, petrophysical/lab analysis).

TOTAL

100%

Notes:

1. The knowledge areas specified as A, B, C, etc. are examples of kinds of knowledge, but they are not exclusive or exhaustive categories.
2. This examination contains 100 multiple-choice questions. Examinee works all questions.
3. The committee chose to fold the Common Knowledge section into the other content sections.

SECTION 3

SPE Guide for Professional Conduct

Preamble

Engineers recognize that the practice of engineering has a vital influence on the quality of life for all people. Engineers should exhibit high standards of competency, honesty, integrity, and impartiality; be fair and equitable; and accept a personal responsibility for adherence to applicable laws, the protection of the environment, and safeguarding the public welfare in their professional actions and behavior. These principles govern professional conduct in serving the interests of the public, clients, employers, colleagues, and the profession.

The Fundamental Principle

The engineer as a professional is dedicated to improving competence, service, fairness, and the exercise of well-founded judgment in the ethical practice of engineering for all who use engineering services with fundamental concern for protecting the environment and safeguarding the health, safety and well-being of the public in the pursuit of this practice.

Canons of Professional Conduct

1. Engineers offer services in the areas of their competence and experience, affording full disclosure of their qualifications.
2. Engineers consider the consequences of their work and societal issues pertinent to it and seek to extend public understanding of those relationships.
3. Engineers are honest, truthful, ethical, and fair in presenting information and in making public statements, which reflect on professional matters and their professional role.
4. Engineers engage in professional relationships without bias because of race, religion, gender, age, ethnic or national origin, attire, or disability.
5. Engineers act in professional matters for each employer or client as faithful agents or trustees disclosing nothing of a proprietary or confidential nature concerning the business affairs or technical processes of any present or former client or employer without the necessary consent.
6. Engineers disclose to affected parties any known or potential conflicts of interest or other circumstances, which might influence, or appear to influence, judgment or impair the fairness or quality of their performance.
7. Engineers are responsible for enhancing their professional competence throughout their careers and for encouraging similar actions by their colleagues.
8. Engineers accept responsibility for their actions; seek and acknowledge criticism of their work; offer honest and constructive criticism of the work of others; properly credit the contributions of others; and do not accept credit for work not their own.
9. Engineers, perceiving a consequence of their professional duties to adversely affect the present or future public health and safety, shall formally advise their employers or clients, and, if warranted, consider further disclosure.
10. Engineers seek to adopt technical and economical measures to minimize environmental impact.
11. Engineers participate with other professionals in multi-discipline teams to create synergy and to add value to their work product.
12. Engineers act in accordance with all applicable laws and the canons of ethics as applicable to the practice of engineering as stated in the laws and regulations governing the

practice of engineering in their country, territory, or state, and lend support to others who strive to do likewise.

— Approved by the SPE Board of Directors 26 September 2004

References

1. National Council of Engineering Examiners: 'Pre-Convention Reports,' 63rd Annual Meeting, San Francisco, California, 12-15 August 1984.
2. T. Scott Hickman, Gus A. Mistrot, and G. Bing Wines: 'The Petroleum Engineer's Professional Responsibility,' SPE #11936. Presented at the 58th Annual Fall Meeting, San Francisco, California, October 1983.
3. Wines, G. Bing: 'Professional Registration and The Petroleum Engineer,' SPE #6742. Presented at the 52nd Annual Fall Meeting, Denver, Colorado, October 1977.
4. Kramer, M. Scott: 'SPE and Professionalism-Views from the Top.' *Journal of Petroleum Technology*, February 1972.
5. Horn, Clifford R.: 'Professional Registration and the Petroleum Engineer.' *Journal of Petroleum Technology*, August 1970.
6. McLemore, Robert H.: 'SPE Must Alter Its Course in the 70's.' *Journal of Petroleum Technology*, January 1969.
7. Brown, Bob Diggs: 'Professionalism-A Must for the Oil Patch.' *Journal of Petroleum Technology*, January 1969.
8. Weber, Arthur W.: 'The Dilemma of the Professional Engineers' Licensing Program.' *Journal of Petroleum Technology*, July 1965.
9. Gillson, Joseph L.: 'Facilitating Registration of AIME Members as Professional Engineers.' *Journal of Petroleum Technology*, July 1964.
10. Pyle, Howard C.: 'Acceptance of Professional Responsibility in the Practice of Petroleum Engineering.' *Journal of Petroleum Technology*, April 1963.
11. Kirkpatrick, C.V.: 'Responsibility: The Professional Educator, The Professions, The Professional Society,' *Journal of Petroleum Technology*, February 1963.
12. Harnish, Douglas H. Jr.: 'The Petroleum Engineering Profession-A Reality or a Contradiction?' *Journal of Petroleum Technology*, November 1962.
13. Young, J.A.: 'Engineers and Scientists-Unions and Professionalism.' *Journal of Petroleum Engineering*, December 1961.
14. Mitchell, Will Jr.: 'Considerations Involved in Clarification of the Engineering Profession.' *Journal of Petroleum Technology*, October 1960.
15. Calhoun, John C. Jr.: 'Petroleum Engineering-It's Place as a Profession.' *Journal of Petroleum Technology*, December 1958.
16. Wickenden, William E.: 'The Second Mile.' *Journal of Petroleum Technology*, February 1950.
17. Bobo, J.E., Reece, C.A.: 'The Advancement of the Petroleum Engineering Professional: Establishment of Professional Competency Guidelines, SPE Paper 56603, 1999.

SECTION 4

Sample SPE Petroleum Engineering Certification Programme Examination

The certification examination will be composed of 100 multiple-choice problems that cover the technical specialty areas described in Section 2.

The main purpose of this sample examination is to illustrate typical problem statements and correct answers for a portion of the topics that may be covered on the exam. Additional topics related to the listed technical specialty areas may also be included in the examination. This sample exam will not prepare you for the exam. It is intended only as a guide. It is recommended that you spend adequate time preparing for the examination. Please note that the sample exam consists of only 80 multiple-choice problems.

**Example Problems
and Correct Answers
for the Sample
Petroleum Engineering
Certification Programme
Examination
for
Petroleum Engineers**

PETROLEUM PROFESSIONAL MORNING SAMPLE EXAM

1. A well is drilling ahead at 10,000 ft MD (9,000 ft TVD) with a BHA comprised of 400 ft of 8-in × 3-in drill collars (147 lb/ft) and 4 1/2-in, 16.60 lb/ft drill pipe (18.40 lb/ft adjusted weight). A bit trip is required. Assume there is no fluid lost to the formation and the drill string is pulled dry (i.e., there is no loss of fluid at the surface).

The total volume (barrels) of drilling fluid required to keep the hole full while tripping completely out of the hole is most nearly:

- I. 54
- II. 67
- III. 79
- IV. 86

2. A production string of 7-inch P-110 casing with a nominal wall thickness of 0.590 inch and a nominal weight per foot of 41 lb/ft is run to TD. Assume yield strength mode of failure in collapse given the D/t range that this particular pipe falls into and that the pipe is submitted to stresses of 50,000 psi axial tension and 11,000-psi internal pressure.

With a safety factor of 1.0, the minimum pressure (psi) that would cause collapse in these conditions is most nearly:

- (A) 27,980
 - (B) 26,684
 - (C) 21,186
 - (D) 16,980
3. A vertical well is drilling ahead at 10,000 ft MD. A bit trip is required and the results of the hydraulics optimization suggest a flow rate of 500 gpm with three 13/32 nozzles (nozzle area = 0.3889 in²). The drilling fluid has a density of 10.0 lb/gal and behaves like a Bingham plastic fluid with a PV of 40 cp and YP of 15 lbf/100 ft². Assume the internal pipe velocity will be 13.953 ft/min and is in the turbulent flow regime with the pressure drops in the annulus and the surface equipment considered negligible.

Assuming 100% mechanical efficiency, the required surface horsepower from the mud pumps to satisfy the proposed hydraulics optimization is most nearly:

- (A) 876
- (B) 1,479
- (C) 1,523
- (D) 3,002

4. While drilling ahead at 10,000 ft MD, a twist-off occurs in the body of the drill pipe. The portion of the body recovered indicates that the top of the fish has a lip that is curled inward.

The option that has the most likely chance of recovering the fish is most nearly:

- (A) Basket overshot
- (B) Bulldog spear
- (C) Rope spear
- (D) Wash pipe

5. Fracture gradients need to be predicted to support a casing program design for a land-based operation in a sedimentary basin. Assume that two primary methods are available for predicting fracture gradient. Method 1 is the Matthew and Kelly model and Method 2 is the Eaton model.

The statement that is **FALSE** is:

- (A) Method 1 assumes a constant regional overburden stress gradient, and Method 2 assumes a variable overburden stress gradient.
- (B) Both methods accommodate formation pressures that are greater than a normal pressure gradient.
- (C) Both methods accommodate formation pressures that are greater than the fracture pressure gradient.
- (D) Both methods assume the mechanical strength of the rock increases with depth.

6. A directional well is to be drilled with a build and hold profile due north with a proposed kick-off point of 3,000 ft MD (3,000 ft TVD), a constant assumed build rate of $3^\circ/100$ ft, and a proposed target of 8,000 ft TVD with a horizontal departure of 1,750 ft.

The measured depth (ft) at the end of the build section is most nearly:

- (A) 1,910
- (B) 3,687
- (C) 4,624
- (D) 8,311

7. A well is drilling ahead with a 9.0-lb/gal brine. The maximum desired particle size is 20 microns. The pit setup is conventional with the flow line discharging into the possum belly, and the centrifuge overflow will be discharged to the reserve pit, if that equipment is selected. The shaker is equipped with 20 mesh screens. The daily rental rates for solids control equipment are shaker, US\$20; desander, US\$25; desilter, US\$30; and centrifuge, US\$50.

The equipment combination that gives the **LEAST** daily cost while satisfying the given design and operational guidelines is most nearly:

- (A) Shaker
 - (B) Shaker; centrifuge
 - (C) Shaker; desander; desilter
 - (D) Shaker; desander; desilter; centrifuge
8. A fluid-filled, vertical well where the MD equals the TVD is drilling ahead with a BHA of fixed length and with a drilling fluid density greater than 8.3 lb/gal. The appropriate available bit weight needs to be identified to minimize drilling costs while maintaining drill string integrity.

Two primary methods are available to calculate the maximum available weight on bit while remaining within design constraints. Method 1 designs on buoyancy and places the neutral point of buckling at the top of the BHA for maximum available weight on bit. Method 2 designs on pressure-area summation of forces and places the axial forces equal to zero at the top of the BHA for maximum available weight on bit. The MD is greater than the fixed length of the BHA.

The statement that is true regarding the maximum available weight on bit for the same fixed BHA length is:

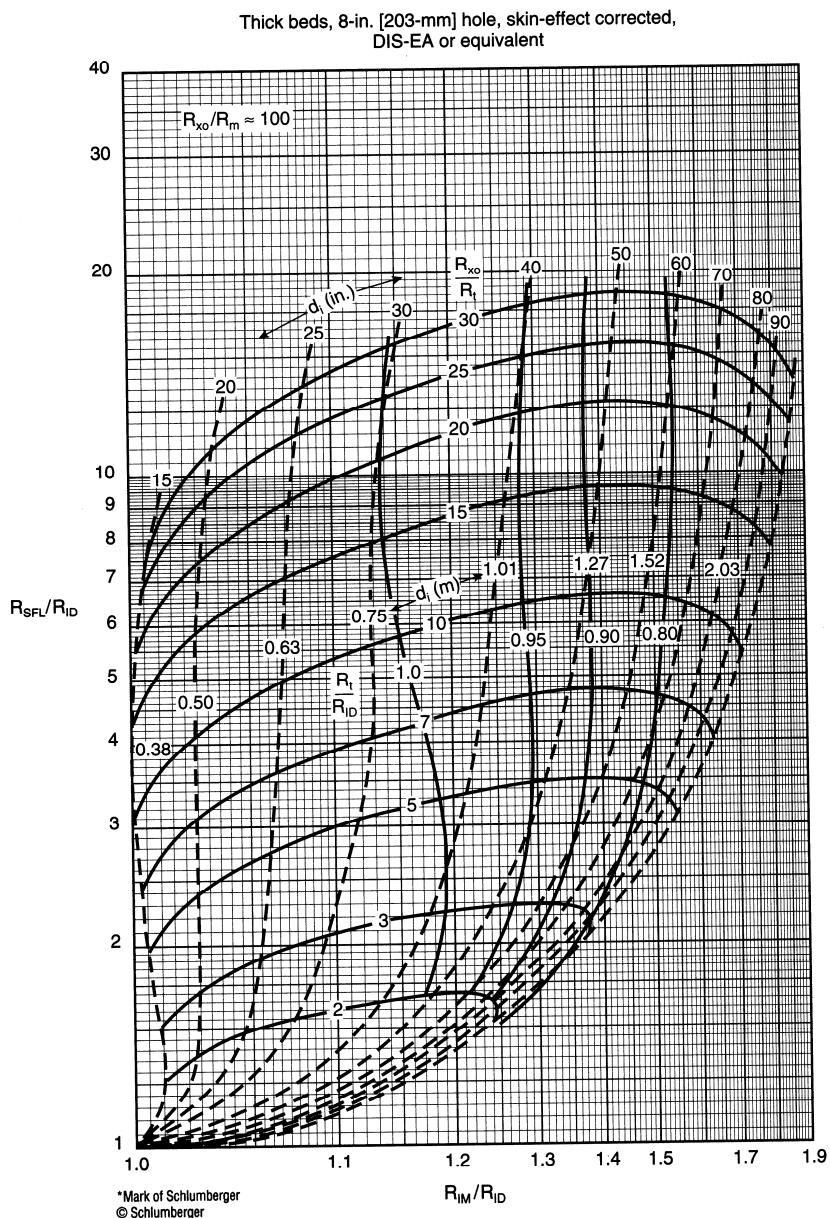
- (A) Method 1 will yield a higher maximum available weight on bit than Method 2.
- (B) Method 2 will yield a higher maximum available weight on bit than Method 1.
- (C) Both methods will result in the same maximum available weight on bit.
- (D) The given information is inadequate to make a prediction between the two methods.

9. An exploratory well has just been logged. The following information was read from the logs across the zone of interest:

Deep induction resistivity 27.6 ohm-meters
 Medium induction resistivity 35.6 ohm-meters
 Focused log resistivity 138 ohm-meters

The true formation resistivity (ohm-meters) is most nearly:

- (A) 26.2
- (B) 27.6
- (C) 29.1
- (D) 31.6



10. The assumption **not** used in the derivation of the radial flow form of the diffusivity equation is:
- (A) Uniform thickness across the reservoir
 - (B) A fluid with small and constant compressibility
 - (C) Homogeneous and isotropic medium
 - (D) Flow into the wellbore continues after the well is shut in.
11. You have the following core analysis from a single zone. All tests used brine with a water resistivity of 0.2613 ohm-meters.

Sample	Permeability y (md)	Porosity y (%)	Ro (ohm-meters)
1	8.64	8.1	34.29
2	17.91	9.6	24.57
3	126.02	12.8	14.21
4	522.04	16.2	8.92

The Archie equation cementation exponent of the formation (m) is most nearly:

- (A) 1.51
 - (B) 1.94
 - (C) 2.01
 - (D) 2.16
12. The conditions under which the extrapolation of the semi-log portion of the Horner plot to $[t_p + \Delta t] / \Delta t = 1$ without further calculations can be used to make a good estimate of average reservoir pressure is most nearly:
- (A) Long flow times in a bounded or multi-well reservoir
 - (B) A good estimate for all test conditions
 - (C) Only when pseudo-steady-state flow was reached during the flow period
 - (D) Short flow periods where the reservoir acts infinite

13. You have the following log responses from an oil bearing limestone formation in a well filled with fresh water as well as the chart below.

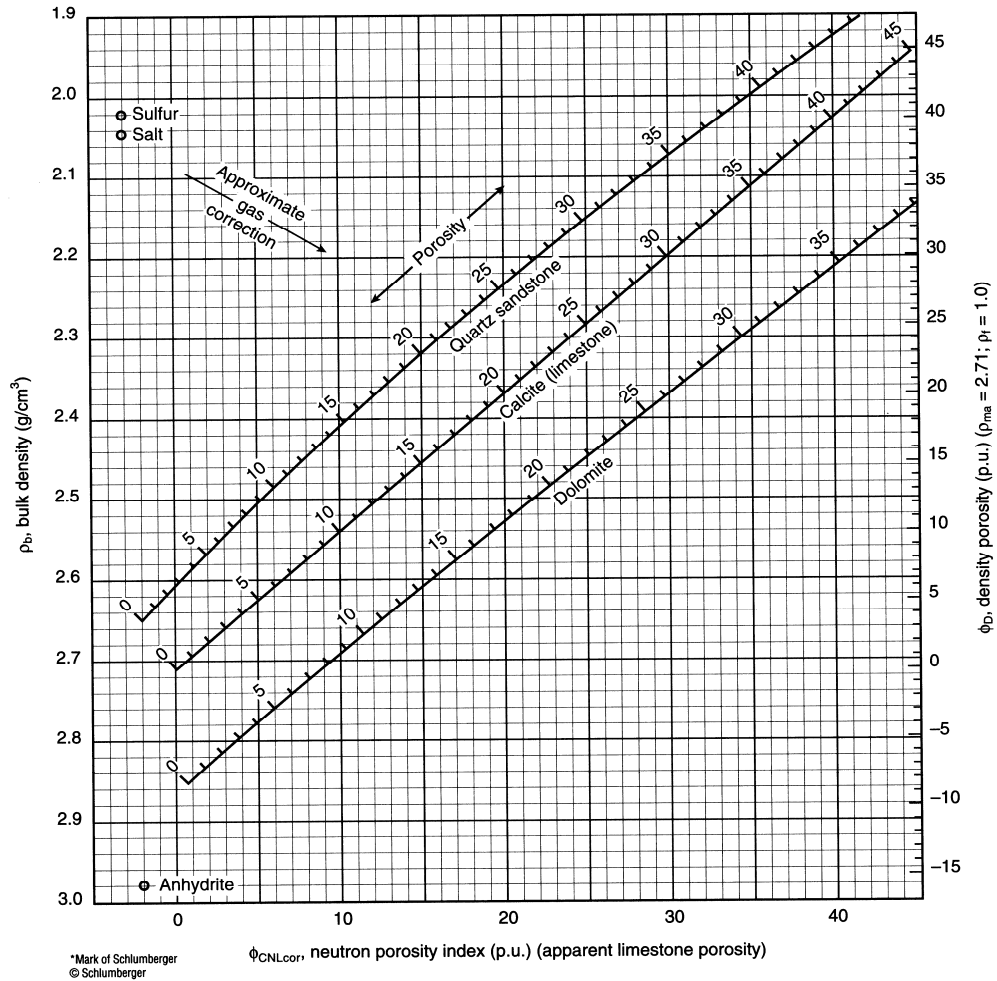
Compensated bulk density 2.46 g/cc
 Interval transit time 60.0 μ sec/ft
 Matrix transit time 47.6 μ sec/ft
 Fluid transit time 189.0 μ sec/ft

The secondary porosity in this zone is most nearly:

- (A) 0.06
- (B) 0.09
- (C) 0.15
- (D) 0.24

Porosity and Lithology Determination from
 Litho-Density* Log and CNL* Compensated Neutron Log

Liquid-filled holes ($\rho_f = 1.000 \text{ g/cm}^3$; $C_f = 0 \text{ ppm}$)



14. You have this core analysis from a single zone. All tests used brine with a water resistivity of 0.2613 ohm-meters.

Sample	Permeability (md)	Porosity (%)	R _o (ohm-meters)
1	8.63	8.0	34.28
2	17.90	9.5	24.56
3	28.60	10.9	19.05
4	126.00	12.7	14.19
5	522.00	16.1	8.88

Porosity (%)	Permeability (md)	Brine Saturation (% Pore Volume)	R _t (ohm-meters)
9	9.41	100.0	26.63
9	9.41	67.5	47.93
9	9.41	50.0	75.89
9	9.41	35.6	127.01

The Archie equation saturation exponent of the formation (n) is most nearly:

- (A) 1.50
- (B) 1.93
- (C) 2.00
- (D) 2.15

15. Consider the following information:

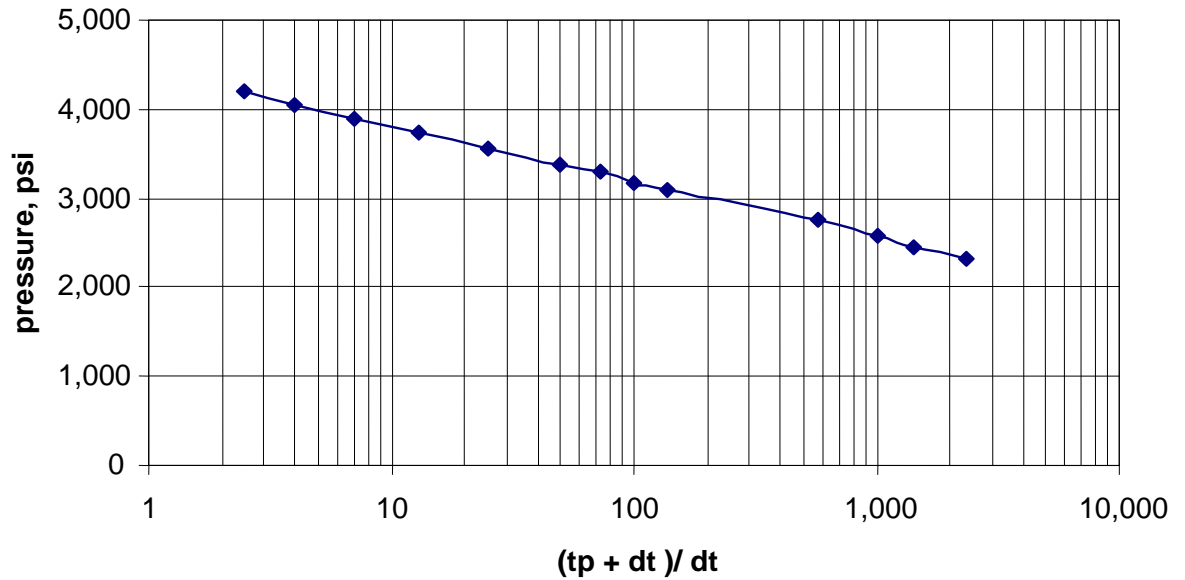
Reservoir thickness 12 ft
 Oil viscosity 0.8 cP
 Wellbore volume 27 barrels
 Oil compressibility 2.5×10^{-4} psi⁻¹
 Assumed reservoir permeability 45 md
 Assumed skin value 2.0
 Formation volume factor 1.22 RB/STB
 Homogeneous reservoir
 Well flows to surface and is above bubble point

In designing a pressure buildup test, the time (hours) to the end of wellbore storage is most nearly:

- (A) 0.04
- (B) 0.45
- (C) 1.29
- (D) 2.25

16. A pressure buildup test was recently conducted in a new well. The well was produced for 3 days at a constant rate of 300 BOPD. The following information was collected during the 3-day flow period and 48-hour shut-in period:

Fluid Properties	Rock Properties
$B_o = 1.27$ RB/STB	$h = 37$ ft
$\mu_o = 0.80$ cP	$c_t = 4.25 \text{ E}-06$
API gravity = 42°	$\phi = 12\%$
$S_w = 23\%$	hole size = 6 inches



The radius (ft) of investigation of the buildup test is most nearly:

- (A) 470 to 530
- (B) 575 to 650
- (C) 740 to 835
- (D) 2,860 to 3,215

17. You have the following information on a rod pumped well:

Pumping unit	API 228-173-100 (operating in the long hole)
Pumping speed	7 SPM
Tubing	2 7/8 inches (2.441 inches I.D.)
Pump	2.25-inch tubing pump
Pump depth	1,000 ft
Rod string	1-inch steel rods
Production rate	
Oil	351 bbl/d
Water	20 bbl/d

Assuming no significant rod stretch, the volumetric efficiency of this lift system is most nearly:

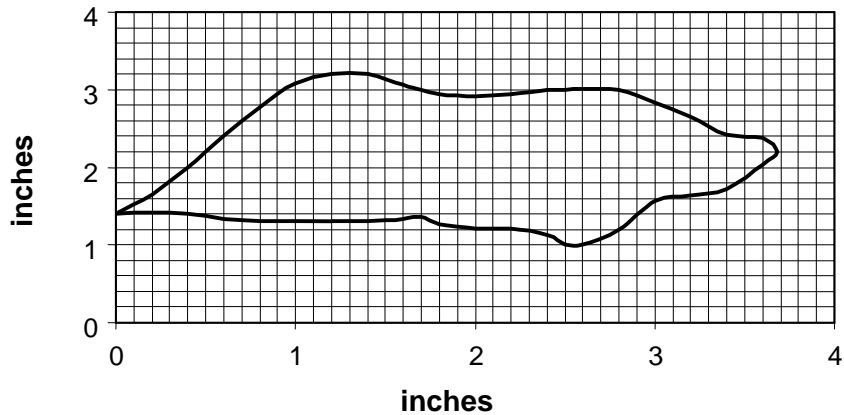
- (A) 90%
 - (B) 85%
 - (C) 76%
 - (D) 52%
18. The operational change that would **LEAST** reduce the torque experienced by a pumping unit system is most likely:
- (A) Reducing the stroke length
 - (B) Reducing the unit's speed
 - (C) Changing the direction of rotation
 - (D) Installing a larger rod string
19. You are designing a separator for a location with limited space. The seam-to-seam length (ft) of a two-phase 30-inch-I.D. horizontal separator needed to handle 1,500 bbl/d and 500 Mscf/d with a liquid retention rate of 3 minutes and operating fluid level at 50% is most nearly:
- (A) 4.9
 - (B) 7.1
 - (C) 9.6
 - (D) 10.6

20. The following dynamometer card was recorded on a beam pumped oil well. The following information is available:

Pumping unit	C-228-173-74
Stroke length	74 inches
Pumping speed	10 SPM
Crank rotation	clockwise
Measured counterbalance	18,065 lb with cranks at 90°
Structural unbalance	0 lb
Rod string	76 API—Grade “C”
100% oil	34 deg. API
Pump size	1.5 inch
Pump depth	8,800 ft
Card constant	1 inch = 5,200 lb

Assume 100% mechanical efficiency.

Dynamometer Card



The difference between the measured counterbalance and the calculated required counter-balance (lbf) is most nearly: (+ is over required weight)

- (A) 822
- (B) -213
- (C) -413
- (D) -3,260

For **Questions 21–22**, refer to the following information:

You are fracing a well and have data from downhole tubing gauges.

Modulus of elasticity of steel			30×10^6 psi
Coefficient of thermal expansion for steel			6.9×10^{-6} in/in/°F
Poisson's ratio			0.30
Packer set at			9,000 ft
Tubing I.D.	2.992 inches	Area	7.031 in^2 (frac string)
Tubing O.D.	3.5 inches	Area	9.621 in^2
Casing I.D.	4.778 inches	Area	12.737 in^2
Casing O.D.	5.500 inches	Area	23.758 in^2
Seal Bore Packer:			
Seal bore I.D.	2.688 inches	Area	5.674 in^2
Seal I.D.	1.937 inches	Area	2.976 in^2
Initial conditions:			
Surface casing pressure			0 psi
Surface tubing pressure			0 psi
Surface temperature			70°F
Bottomhole temperature			160°F
Density of fluid (both tubing and annulus)			9.0 lb/gal
Final pumping conditions:			
Surface casing pressure			1,000 psi
Surface tubing pressure			6,100 psi
Bottomhole tubing pressure (@ packer)			7,800 psi
Surface temperature			70°F
Bottomhole temperature			70°F
Density of fluid in annulus			9.0 lb/gal

21. If the tubing is latched into the packer, the force change (lb) due to the temperature effect is most nearly:
- (A) 48,300 tension
 - (B) 27,700 tension
 - (C) 27,700 compression
 - (D) 24,100 tension

22. If the tubing is latched into the packer, the force change (lb) due to the ballooning effect is most nearly:
- (A) 20,400 tension
 - (B) 20,000 tension
 - (C) 14,700 tension
 - (D) 9,400 tension

23. You are fracing a well and have been given the following information:

Modulus of elasticity of steel			30×10^6 psi
Coefficient of thermal expansion for steel			6.9×10^{-6} in/in/°F
Poisson's ratio			0.30
Packer set at			8,500 feet
Tubing I.D.	2.992 inches	Area	7.031 in^2 (frac string)
Tubing O.D.	3.5 inches	Area	9.621 in^2
Casing I.D.	6.094 inches	Area	29.17 in^2
Casing O.D.	7.000 inches	Area	38.49 in^2
Seal bore packer:			
Seal bore I.D.	3.00 inches	Area	7.07 in^2
Seal I.D.	2.28 inches	Area	4.08 in^2
Initial conditions:			
Surface casing pressure			0 psi
Surface tubing pressure			0 psi
Surface temperature			75°F
Bottomhole temperature			160°F
Density of fluid (both tubing and annulus)			9.5 lb/gal
Final pumping conditions:			
Surface casing pressure			500 psi
Surface tubing pressure			5,500 psi
Bottomhole tubing pressure (@ packer)			7,000 psi
Surface temperature			75°F
Bottomhole temperature			75°F
Density of fluid in annulus			9.5 lb/gal

If the tubing is free to move, the length change (inches) due to the piston effect is most nearly:

- (A) -8.2
- (B) -1.8
- (C) -1.4
- (D) +0.1

24. You are planning to perforate a sand at 9,160 ft with a 500-psi underbalance. The sand has a 4,525-psi reservoir pressure, and the hole is full of 9.5-lb/gal fluid. Assuming any nitrogen cushion would have a gradient of 0.1 psi/ft, the following condition that would achieve the desired underbalance is most nearly:
- (A) Existing well fluid swabbed to 3,050 ft plus a nitrogen cushion with a 700-psi surface pressure
 - (B) Existing well fluid swabbed to 2,030 ft plus a nitrogen cushion with an 800-psi surface pressure
 - (C) Existing well fluid swabbed to 2,630 ft plus a nitrogen cushion with an 800-psi surface pressure
 - (D) All of the above are within 25 psi of the desired underbalance
25. A reciprocating compressor is designed to compress 2.0 MMscf/d (S.G. 0.65) with a suction temperature of 150 degrees, a suction pressure of 200 psig, and a discharge pressure of 1,000 psig. The minimum number of stages to achieve this design is most nearly:
- (A) One
 - (B) Two
 - (C) Three
 - (D) Four
26. A 24-hour production test was obtained for a new oil well completed with 2 7/8-inch-O.D., 6.5-lb/ft, EUE 8rd tubing. The following well and test information is available for analysis:

Well data:

Well depth	6,502 ft
Casing setting depth	6,492 ft
Tubing setting depth	6,003 ft
Perforations (mid-perf)	6,076 ft

Reservoir data:

Initial reservoir pressure	2,800 psia
Bubble point pressure	2,400 psia
Current reservoir pressure	2,200 psia

Production test data:

Oil production rate	421 bbl/d
Gas production rate	170 Mscf/d
Flowing bottomhole pressure	1,100 psia
Flow efficiency	0.70 (from pressure transient analysis)

Assume Vogel's inflow performance relationship (IPR) applies. If the flow efficiency is improved to 1.0, the maximum production rate or absolute open flow (STB/day) is most nearly:

- (A) 420
- (B) 525
- (C) 600
- (D) 860

27. The following information is available for an economic analysis of an oil property that is being purchased.

Cash flow analysis information:

Annual discount rate 15% compounded annually
 Discounting convention end of year
 Lease purchase price US\$700,000 paid up front
 Lease abandonment costs US\$50,000 paid at the end of the last year of production
 Salvage value zero

Year	Revenue, \$	Expenses including taxes, US\$
1	1,090,000	444,000
2	605,000	274,000
3	334,000	178,000

The present worth of this acquisition is most nearly:

- (A) US\$182,000
 (B) US\$220,000
 (C) US\$280,000
 (D) US\$385,000
28. You are required to replace the tubing in an 8,000-ft gas well with 3 1/2-inch EUE tubing stabbed into a permanent seal bore packer at 7,800 ft with a 1.71-inch profile nipple in the tail of the packer. The 3 1/2-inch string also includes a sliding sleeve one joint above the top of the seals. Reservoir pressure has dropped to 2,000 psi, and water production has recently been causing the well to load up. Therefore, it has been decided to increase the velocity in the well by replacing the 3 1/2-inch tubing with 2 3/8-inch tubing.

Select the procedure to replace the tubing that will provide proper well control and minimize the exposure of the producing interval to water.

- (A) I. Rig up wireline unit and wireline lubricator. Set a plug in the profile nipple.
 II. Rig up workover rig.
 III. Fill tubing with water.
 IV. Nipple down tree.
 V. Nipple up BOPE with 3 1/2-inch pipe rams.
 VI. Pull and lay down 3 1/2-inch tubing.
 VII. Pick up and run in with 2 3/8-inch tubing.
 VIII. Circulate in packer fluid.
 IX. Stab into packer and land tubing.
 X. Nipple down BOPE.
 XI. Nipple up tree and tie in production line.

- nipple.
- XII. Rig up wireline unit and wireline lubricator. Recover the plug from the profile
 - XIII. Swab well in.
 - XIV. Rig down workover rig.

- (B)
- I. Rig up wireline unit and wireline lubricator. Set a plug in the profile nipple.
 - II. Rig up workover rig.
 - III. Fill tubing with water.
 - IV. Nipple down tree.
 - V. Pull and lay down 3 1/2-inch tubing.
 - VI. Pick up and run in with 2 3/8-inch tubing.
 - VII. Circulate in packer fluid.
 - VIII. Stab into packer and land tubing.
 - IX. Swab fluid in tubing down to a point where only 1,500 psi of head is present.
 - X. Nipple up tree and tie in production line.
 - XI. Rig up wireline unit and wireline lubricator. Recover the plug from the profile nipple.
 - XII. Swab well in.
 - XIII. Rig down workover rig.

- (C)
- I. Rig up wireline unit and wireline lubricator. Set a plug in the profile nipple.
 - II. Rig up workover rig.
 - III. Fill tubing with water.
 - IV. Nipple down tree.
 - V. Nipple up BOPE with 3 1/2-inch pipe rams.
 - VI. Pull and lay down 3 1/2-inch tubing.
 - VII. Change out pipe rams from 3 1/2 inches to 2 3/8 inches.
 - VIII. Pick up and run in with 2 3/8-inch tubing.
 - IX. Circulate in packer fluid.
 - X. Stab into packer and land tubing.
 - XI. Swab fluid in tubing down to a point where only 1,500 psi of head is present.
 - XII. Nipple down BOPE.
 - XIII. Nipple up tree and tie in production line.
 - XIV. Rig up wireline unit and wireline lubricator. Recover the plug from the profile nipple.
 - XV. Swab well in.
 - XVI. Rig down workover rig.

- (D)
- I. Rig up workover rig.
 - II. Rig up wireline and wireline lubricator. Run in hole with shifting tool and open sliding sleeve.
 - III. Circulate in kill fluid.
 - IV. Nipple down tree.
 - V. Nipple up BOPE with 3 1/2-inch pipe rams.
 - VI. Pull and lay down 3 1/2-inch tubing.
 - VII. Change out pipe rams from 3 1/2 inches to 2 3/8 inches.
 - VIII. Pick up and run in with 2 3/8-inch tubing.
 - IX. Circulate in packer fluid.
 - X. Stab into packer and land tubing.

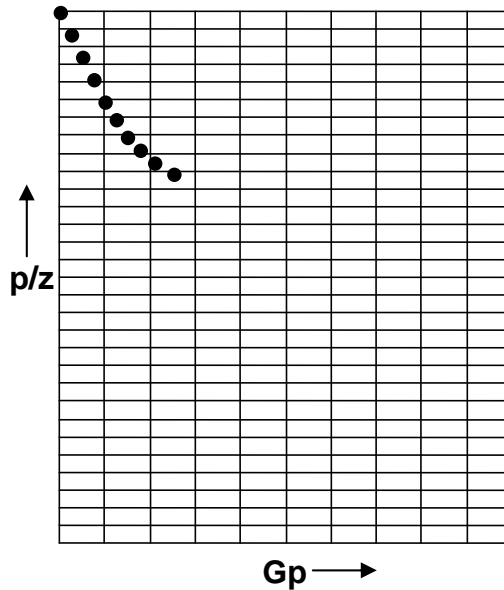
- XI. Swab fluid in tubing down to a point where only 1,500 psi of head is present.
- XII. Nipple down BOPE.
- XIII. Nipple up tree and tie in production line.
- XIV. Swab well in.
- XV. Rig down workover rig.

29. An oil lease is currently producing at a rate of 284 STB/D. The rate has been declining at a constant percentage of 30% per year (loss ratio = 0.3).

If the economic limit on production is 60 STB/D, the remaining oil reserves (STB) for the lease would be most nearly:

- (A) 630
- (B) 19,100
- (C) 229,200
- (D) 272,500

30. A homogeneous gas reservoir has been producing gas (but no water). The figure below is a plot of p/z vs. G_p .



The deviation from a straight line in this plot most likely shows that:

- A. there has been no water influx
- B. there has been water influx
- C. the well has become damaged
- D. the reservoir pressure has fallen below the dew point pressure

31. Reserves for high-pressure volumetric dry gas reservoirs are often obtained by extrapolating a plot of p/z vs. G_p to the abandonment point.

Equivalent results could be obtained by plotting:

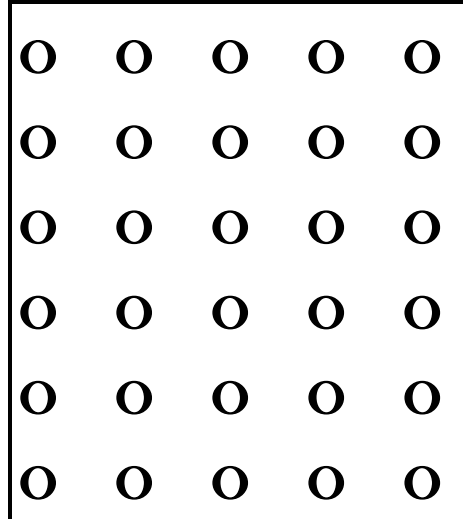
- (E) $1/B_g$ vs. G_p
- (F) p vs. G_p
- (G) p^2 vs. G_p
- (H) B_g vs. G_p

32. A dry gas reservoir has an estimated bulk volume of 9,418 acre-feet, an average porosity of 0.20, and an initial water saturation of 0.35.

If the gas formation volume factor is $0.004503 \text{ ft}^3/\text{scf}$, the initial gas in place (MMscf) is most nearly:

- (A) 211
- (B) 6,380
- (C) 11,800
- (D) 18,200

33. The drawing below represents a group of oil wells that are to be subjected to a water flood using a five-spot pattern.



To achieve this pattern one should:

- (A) convert alternate horizontal rows of wells to injectors
- (B) convert alternate diagonal rows of wells to injectors
- (C) convert alternate vertical rows of wells to injectors
- (D) convert alternate wells in every diagonal to injectors

34. A new oil well is expected to produce at the allowable rate of 250 STB/D for the first 18 months and then start a constant percentage decline of 5% per month.

Using this scenario, the total production of oil (thousand STB) during the second year of the productive life would be most nearly:

- (A) 40
- (B) 68
- (C) 85
- (D) 176

35. An oil lease is currently producing at a rate of 450 STB/D. The rate has been declining at a constant percentage of 30% per year (loss ratio = 0.3).

If the economic limit on production is 60 STB/D, the remaining productive life (months) for the lease would be most nearly:

- (A) 5.6
- (B) 29
- (C) 68
- (D) 81

36. A dry gas reservoir had initially 11,844 MMscf of gas in place with a formation volume factor of 0.004503 res ft³/scf. 6,097 MMscf of gas has been produced along with 1,205 STB of water ($B_w = 1.035$ res ft³/scf). The present formation volume factor is 0.004896 res ft³/scf.

The volume of water influx (million ft³) at this time is most nearly:

- (A) 6.11
- (B) 18.2
- (C) 25.2
- (D) 32.2

37. A waterflood is planned for a depleted oil reservoir having a bulk volume of 1,289 acre-feet, a porosity of 0.22, and an initial (connate) water saturation of 0.26. The reservoir has produced oil and gas (no water) to a point where the average gas saturation is 0.11. Formation volume factors for oil and water are 1.36 and 1.0 respectively, and the residual oil saturation to water is 0.28.

Assuming a residual gas saturation of 0 and no oil production before fillup, the volume of water (thousand STB) necessary to reach liquid fillup in the reservoir is most nearly:

- (I) 180
- (J) 240
- (K) 560
- (L) 770

38. A waterflood is planned for a depleted oil reservoir having a bulk volume of 1,289 acre-feet, a porosity of 0.22, and an initial (connate) water saturation of 0.26. The reservoir has produced oil and gas (no water) to a point where the average gas saturation is 0.11. Formation volume factors for oil and water are 1.36 and 1.0 RB/STB respectively.

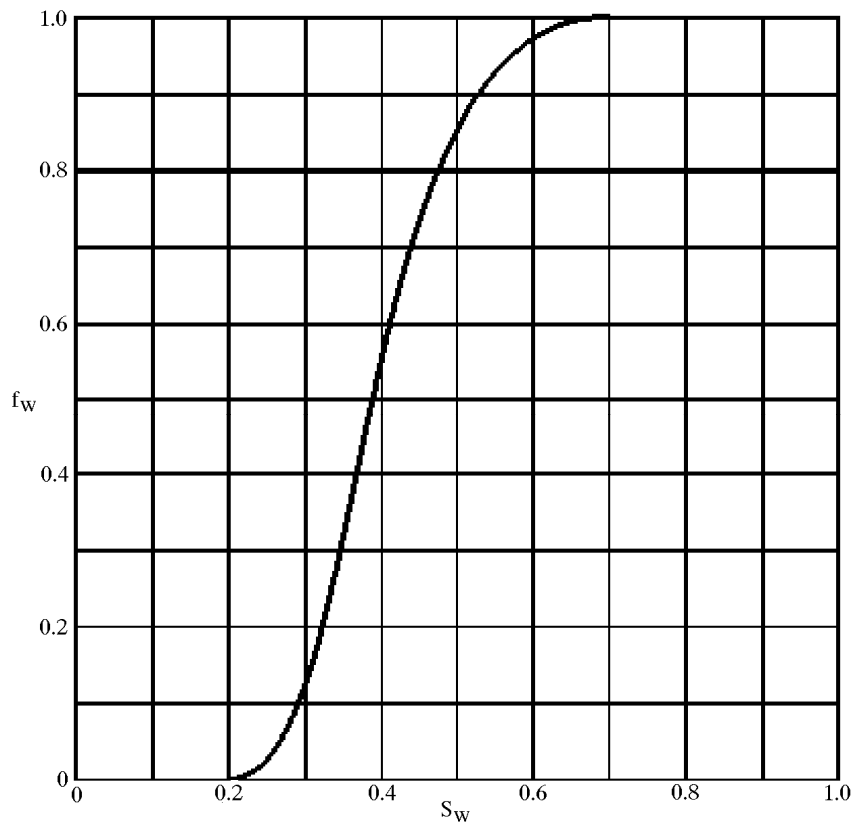
If the residual oil saturation for the waterflood is 0.28, the maximum volume (thousand STB) of oil which could be recovered by the waterflood would be most nearly:

- (M) 570
- (N) 770
- (O) 1,010
- (P) 1,380

39. An oil reservoir that is to be produced by waterflood has the fractional flow curve shown below. Assume that the initial water saturation is immobile.

According to the frontal displacement theory, the average water saturation in the swept region and prior to water breakthrough would be most nearly:

- (A) 0.45
- (B) 0.55
- (C) 0.60
- (D) 0.70



40. A new well is completed in the test reservoir. The reservoir temperature and pressure are measured at 6,000 psia and 172°F, respectively. There is a strong aquifer that will maintain reservoir pressure above 5000 psia. Analysis of the reservoir fluid shows an undersaturated oil with the following PVT properties.

Test Reservoir PVT Data

Flash Liberation		Differential Liberation	
Pressure	$T_{res} = 172^\circ\text{F}$ Relative Volume V/V_{sat}	$T_{res} = 172^\circ\text{F}$ Relative Oil Volume, B_{od} res bbl/STB	Solution GOR scf/STB
psia			
6,000	0.9867		
5,000	0.9986		
4,895	1.0000	1.5389	1,085
4,500	1.0180	1.4881	973
4,000	1.0489	1.4352	846
3,000	1.1534	1.3407	621
2,000	1.4323	1.2579	418
1,000	2.4257	1.1806	228
15		1.0571	0

Reservoir Oil Flash Liberation Test

	Primary Sep. Conditions	Stock Tank Conditions	Standard Conditions
Pressure, psia	1,162	15.025	15.025
Temperature, °F	87	72	60

Type of Liberation	Gas/Oil Ratio scf/STB			Formation Vol Factor, B_{obf}
	Primary Sep.	Stock Tank	Total Soln Gas	
Separator oil to stock tank	724	287	1,011	1.4927
Reservoir oil to stock tank			1,092	

Shrinkage 0.888 STB/B at primary separator

You have determined that the optimal separator conditions are to produce the new reservoir through a single primary separator and then to commingle the fluids in the stock tanks. The OOIP is estimated at 2.2 million reservoir barrels. Oil is being allocated based on volumes measured at the primary separator.

The OOIP, in millions of primary separator barrels, is most nearly:

- (E) 1.47
- (F) 1.49
- (G) 1.68
- (H) 1.98

**Correct Answers to the Petroleum Engineering
Morning Sample Exam**

101	D
102	C
103	A
104	A
105	C
106	B
107	C
108	A
109	A
110	D
111	B
112	D
113	A
114	A
115	D
116	A
117	A
118	D
119	C
120	B

121	D
122	C
123	B
124	A
125	B
126	D
127	A
128	C
129	C
130	B
131	A
132	C
133	B
134	C
135	C
136	C
137	B
138	A
139	B
140	C

PETROLEUM

**PETROLEUM CERTIFICATION
PROGRAMME**

AFTERNOON SAMPLE EXAM

PETROLEUM

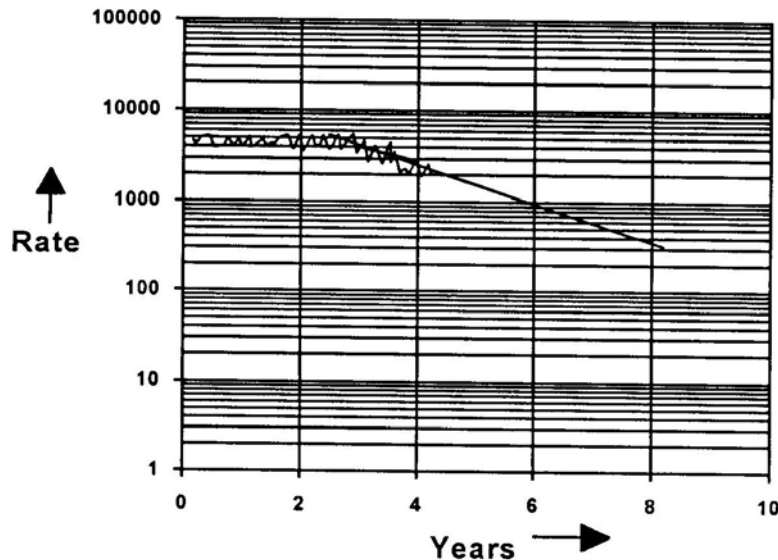
1. A new well is completed in the test reservoir. It will be producing through a single primary separator with the fluids to be commingled in the stock tanks. The stock tanks have vapor recovery. The gas-oil ratio for the primary separator is 724 scf/STB, and the oil shrinkage at the primary separator is 0.888 STB/bbl. The reservoir oil formation volume factor is 1.4927 res bbl/STB, and the gas-oil ratio for the first month's production averages 1,011 scf/STB.

The GOR at the primary separator (measured in scf/bbl of primary separator liquids) would be most nearly:

- (A) 486
 - (B) 640
 - (C) 724
 - (D) 815
2. An oil-producing lease has the production decline curve shown below. The best-fit straight line shows that the production rate declined from 4,075 STB/month at the end of Year 3 to 2,845 STB/month at the end of Year 4.

The annual nominal decline rate (%) is most nearly:

- (A) 30
- (B) 36
- (C) 39
- (D) 43



PETROLEUM

3. A commercial oil reservoir has recently been discovered.

If water influx is present but ignored in early material balance calculations of original oil in place, the calculated value for OOIP would most likely be:

- (A) too high
- (B) too low
- (C) correct
- (D) independent of water influx

4. A commercial oil reservoir has recently been discovered.

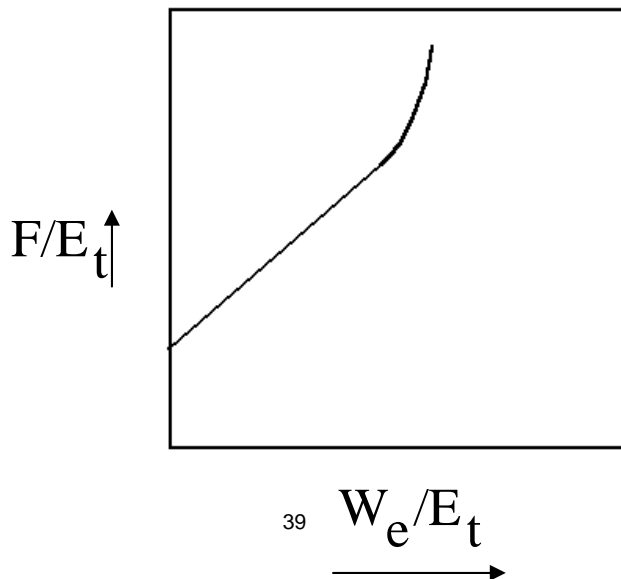
If the oil reservoir is producing at pressures above the bubble point pressure, the factor in material balance calculations that is **FAR MORE IMPORTANT** than if the reservoir were producing below the bubble point pressure is:

- (A) Water influx
- (B) Dip angle of the reservoir
- (C) Produced gas/oil ratio
- (D) Formation compressibility

5. An oil reservoir with no gas cap is being produced with natural aquifer drive. The figure shown is the result of using the Havelena-Odeh method for analysis by material balance.

This chart indicates that the water influx term in the equation is most likely:

- (A) too large
- (B) too small
- (C) correct
- (D) cannot tell from information given



PETROLEUM

6. For a well in a dry gas reservoir you have the following information:

Well spacing	500 acres
Net sand thickness	50 feet
Porosity	0.15
Initial water saturation	0.22
Reservoir temperature	189°F
Reservoir pressure	5,257 psia
Gas deviation factor (at 5,257 psia)	1.015

The original gas in place (MMscf) is most nearly:

- (A) 7,000
 - (B) 33,000
 - (C) 36,000
 - (D) 46,000
7. A volumetric (no water influx) dry gas reservoir had an initial pressure of 4,750 psia with a gas deviation factor of 0.975.

At an abandonment reservoir pressure of 1,500 psia with a gas deviation factor of 0.892, the gas recovery factor (%) would be most nearly:

- (A) 34.5
 - (B) 65.5
 - (C) 68.4
 - (D) 71.1
8. A gas well is producing with a sand face pressure above the dew point pressure. The surface producing gas/liquid ratio is 15,000 scf of surface gas ($\gamma_g = 0.67$) per STB of condensate ($\gamma_o = 0.759$, $M_o = 124$).

The specific gravity of the produced reservoir gas (fraction, air = 1.0) is most nearly:

- (A) 0.675
- (B) 0.705
- (C) 0.855
- (D) 1.015

PETROLEUM

9. A dry gas reservoir had an original gas in place of 12,000 MMscf at a pressure of 3,500 psia ($B_{gi} = 0.86625$ M res bbl/MMscf). Cumulative production to a reservoir pressure of 2,500 psia is 3,500 MMscf of gas ($B_g = 1.17275$ M res bbl/MMscf) and 100 MSTB of water ($B_w = 1.04$ res bbl/STB).

The cumulative water influx (M res bbl) during this period is most nearly:

- (A) 410
- (B) 530
- (C) 2,510
- (D) 2,980

10. A currently depleted and shut-in oil reservoir originally contained 10,000 (thousand STB) of under-saturated oil with a formation volume factor of 1.3389 res bbl/STB and a connate water saturation of 0.35. Cumulative oil production to date has been 937.5 (thousand STB) of oil. The oil formation volume factor is now 1.2761 res bbl/STB.

Assuming no water influx, the current oil saturation is most nearly:

- (A) 0.30
- (B) 0.56
- (C) 0.60
- (D) 0.62

11. An associated oil and gas reservoir has a total bulk volume of 32,500 acre-feet. The bulk volume of the gas cap at original conditions was 7,333 acre-feet. The following table applies to the original and present conditions.

Conditions	Pressure (psia)	B_o (res bbl/STB)	B_g (res bbl/STB)	R_s (scf/STB)	Cum. Oil Prod. (thousand STB)	Cum. Gas Prod. (MMscf)
Original	2,500	1.4301	0.001219	875	0	0
Present Time	2,200	1.3883	0.001376	766	263	464

The original oil in place (STB/ac-ft) is most nearly:

- (A) 4,250
- (B) 4,500
- (C) 4,850
- (D) 6,700

PETROLEUM

12. A homogeneous oil reservoir has no original gas cap. The original reservoir pressure is 3,200 psia, which is also the bubble point pressure. Rock and water compressibilities may be assumed negligible. All wells logged oil to the base of the sand. Assume zero water influx. You have the following additional information:

Pressure (psia)	B_o (res bbl/STB)	B_g (res bbl/Mscf)	R_s (scf/STB)
3,200	1.5685	0.8192	1,125
2,400	1.4622	1.0737	850

After production of oil and gas by pressure depletion to an average reservoir pressure of 2,400 psia, re-injection of the produced gas would most likely:

- E. increase the recovery
 - F. decrease the recovery
 - G. change the recovery but one needs to know the gas re-injection rate to determine whether it increases or decreases
 - H. have no effect on the recovery
13. A 10,000-ft string of 2 3/8-inch, 4.7-lb/ft tubing is stuck in the hole. After pulling tension into the string, the weight indicator reads 57,000 lb (10,000 lb over string weight), and 20 inches of tubing stretch is seen at the surface.

The depth (ft) at which the tubing is stuck is most nearly:

- (A) 1,150
 - (B) 1,600
 - (C) 5,990
 - (D) 6,520
14. A well is going to be perforated using tubing conveyed guns run below a packer on a 3 1/2-inch tubing string. The completion interval was selected from open hole logs including induction, neutron, density, gamma ray, and spontaneous potential logs. Cased-hole log suite has been completed which included cement bond, neutron, gamma ray, and collar locator logs. The cased-hole logs are on depth with the open-hole logs.

The method of correlation that would give the greatest accuracy of setting the packer and firing the guns on depth is most likely:

- (I) Run a new neutron–gamma ray log to correlate with open-hole logs.
- (J) Run a collar strip to correlate with the existing collar log, which is known to be on depth.
- (K) Tag the plug back TD and correct based on that information.
- (L) Strap-in the tubing and adjust for pipe stretch.

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15. State regulations require a cement plug from the bottom perf to 100 ft above the top perf. You plan to lay a single balanced cement plug that will fulfill the requirements to the letter. Assume no excess is required and the weights of the fluid in the hole and the displacing fluid are equal. The following information is given:

Casing 7-inch, 23-lb/ft cemented at 4,040 ft
Plug back depth 4,000 ft
Perforations 3,900 ft–3,700 ft and 3,650 ft–3,600 ft, four 1/2-inch JHPF
Work string 3½-inch, 9.3-lb/ft EUE tubing

Excluding pumps and lines, the volume (bbl) of displacement required is most nearly:

- (A) 31.6
- (B) 31.3
- (C) 31.1
- (D) 30.1

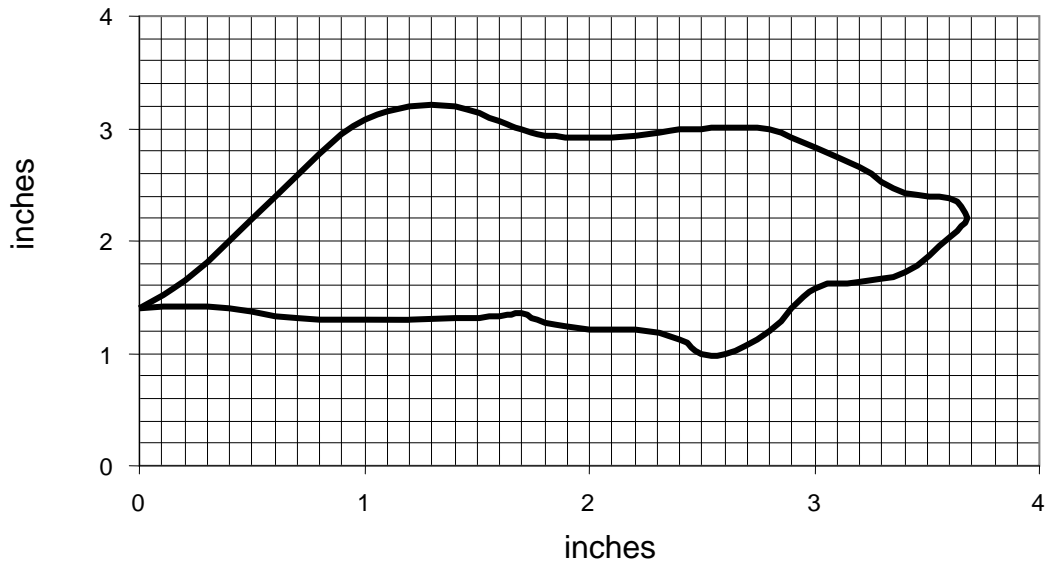
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For **Questions 16–17**, the following dynamometer card was recorded on a beam pumped oil well. The following information is available:

Pumping unit	C-228-173-74
Stroke length	74 inches
Pumping speed	10 SPM
Crank rotation	Clockwise
Measured counterbalance	18,065 lb with cranks at 90°
Structural unbalance	710 lb
Rod string	76 API
Depth to 1.5-inch pump	8,800 ft
Card constant	1 inch = 5,200 lb

Assume 100% mechanical efficiency.

Dynamometer Card



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Crank Angle (deg)	Rod Position (fraction)	Torque Factor (in)
0	0.001	-2.404
15	0.017	13.437
30	0.079	28.372
45	0.181	39.482
60	0.308	44.956
75	0.442	45.09
90	0.571	41.616
105	0.687	36.348
120	0.786	30.449
135	0.867	24.394
150	0.931	18.165
165	0.975	11.452
180	0.997	3.8
195	0.996	-5.154
210	0.966	-15.281
225	0.905	-25.616
240	0.815	-34.629
255	0.702	-41.076
270	0.575	-44.467
285	0.442	-44.824
300	0.312	-42.266
315	0.194	-36.8
330	0.097	-28.311
345	0.029	-16.734
360	0.001	-2.404

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16. The minimum polished rod load (lbf) is most nearly:
- (A) 5,200
 - (B) 6,500
 - (C) 7,280
 - (D) 16,640
17. The maximum stress (psi) in the top rod during the pumping cycle is most nearly:
- (A) 21,734
 - (B) 24,226
 - (C) 27,687
 - (D) 37,647
18. A waterflood project is being implemented in a reservoir at 3,200 ft. Several water supply wells will be required. A study has been initiated to determine the economic impact of drilling wells using 7-inch casing and 7-inch pumps versus 5½-inch casing and 5½-inch pumps. The following data is available:

Well Data:

Mid-perforation	3,250 ft
Static fluid level	300 ft below surface
Casing depth	3,400 ft
Tubing size	2 7/8 inch, 6.5 lb/ft, EUE
Pump setting depth	2,000 ft
Performance curve for ESPs	on following pages

Equipment Prices:

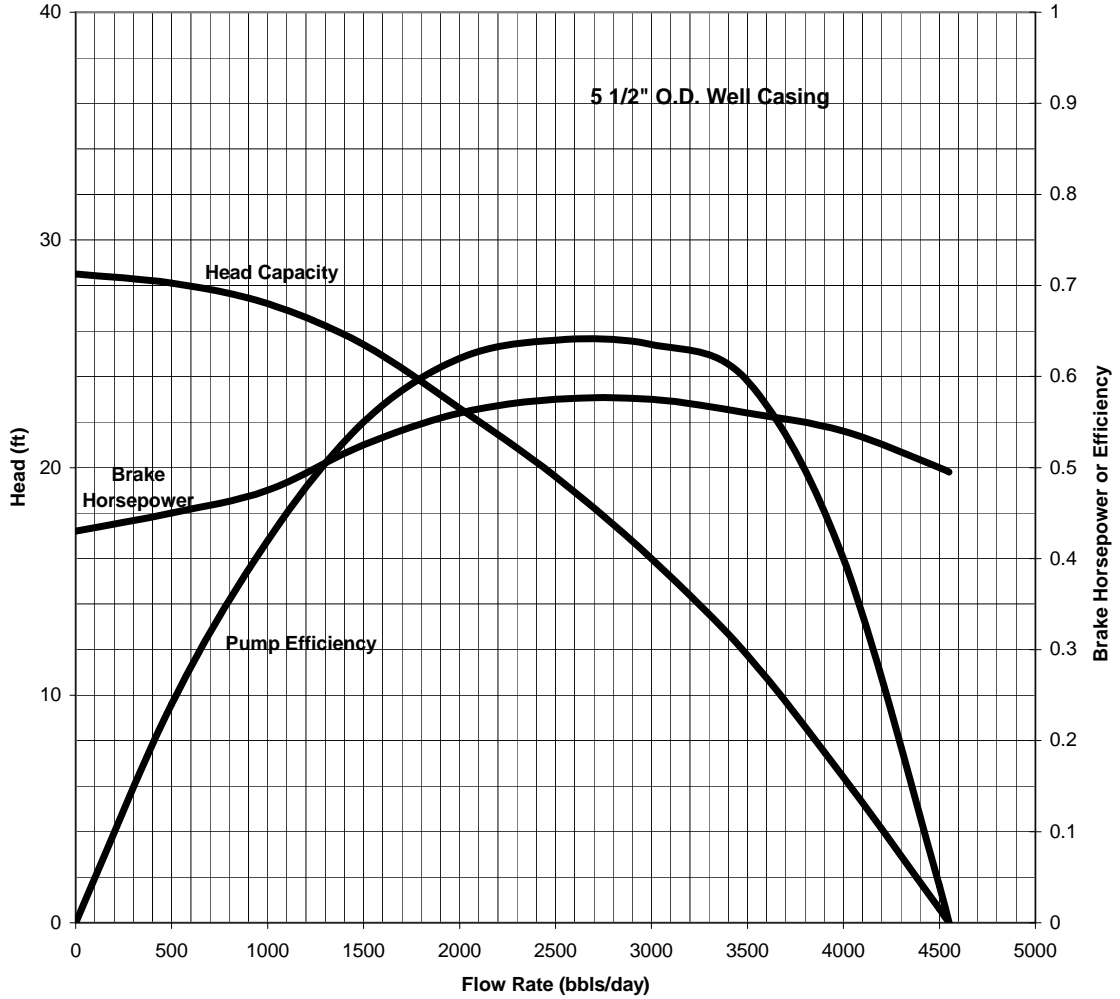
7-inch casing	\$14.18/ft – includes incremental drilling cost
5½-inch casing	\$12.15/ft
7-inch ESP	\$40.80/stage
5½-inch ESP	\$27.90/stage
Motors	\$25/hp
Remaining equipment	No difference

A total dynamic head of 1,860 ft is required for each well. The cost (\$) of the most economical option to produce 3,000 bbls of water per day is most nearly:

- V. 44,500
- VI. 46,200
- VII. 51,400
- VIII. 53,100

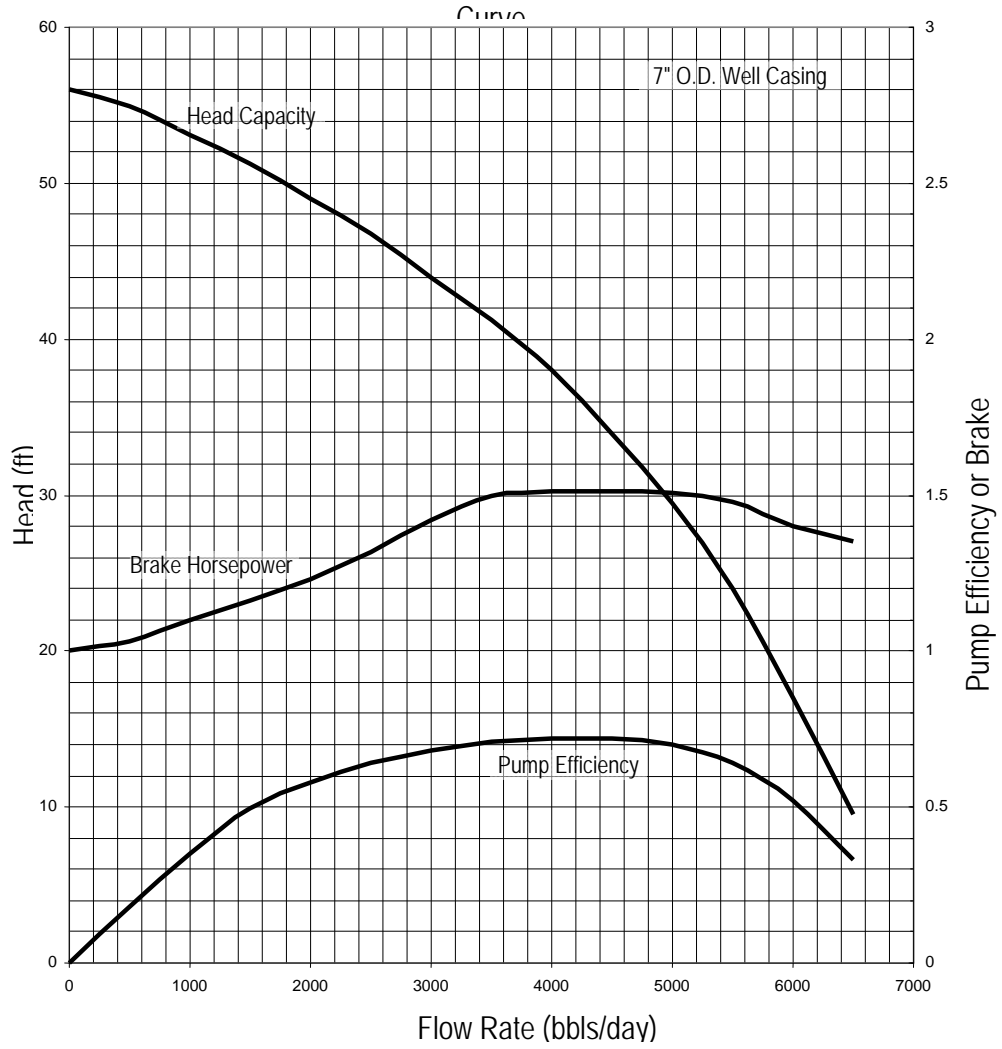
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Submersible Pump
N-80 One Stage Performance Curve
Series 400, 3475 RPM, (S.G. 1.0)



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Submersible Pumps E-127 One Stage Performance



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19. A mini-frac was performed using 8.34-lb/gal frac fluid at a pump rate of 30 BPM. The treatment interval had an initial reservoir pressure of 3,000 psi and a depth of 6,000 ft. The following wellhead pressures were obtained during the mini-frac:

Pre-job pressure 402 psi
Average treatment pressure 2,110 psi
Maximum treating pressure 2,238 psi
Initial shut-in pressure 1,710 psi

The frac gradient (psi/ft) is most nearly:

- (A) 0.50
 - (B) 0.72
 - (C) 0.78
 - (D) 0.81
20. The orifice plate in a gas meter should be installed with the sharp edge:
- (A) upstream
 - (B) downstream
 - (C) parallel to the flow stream
 - (D) it does not matter
21. Assume that 2.0 MMscf/d of natural gas is saturated with water vapor at 100°F and 1,000 psig. The amount of water vapor (pounds) that must be removed per day to condition the gas to sales line specification (7 lb/MMcf) is most nearly:
- (A) 14
 - (B) 58
 - (C) 116
 - (D) 232
22. The item that will **NOT** generally change the inflow performance for an oil well is:
- (M) A decrease in K_{ro} as gas saturation increases
 - (N) An increase in oil viscosity as reservoir pressure decreases
 - (O) Formation damage around the wellbore ($S > 0$)
 - (P) Water influx such that reservoir pressure remains constant

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23. An oil well is producing under pseudo-steady-state conditions with the following information available for analysis:

Productive area	120 acres
Productive bulk volume	3,600 acre-feet
Average reservoir pay thickness	30 ft.
Porosity	28%
Water saturation	20%
Permeability	75 md
Wellbore diameter	12 inches
Bubble point pressure	2,800 psia

Pressure (psia)	Oil Formation Volume Factor (res bbl/STB)	Solution Gas-Oil Ratio (scf/STB)	Oil Viscosity (cP)
3,600	1.3928	750	0.5525
3,400	1.3957	750	0.5344
3,200	1.3990	750	0.5163
3,000	1.4026	750	0.4981
2,800	1.4066	750	0.4800
2,700	1.3918	721	0.4882

For an average reservoir pressure of 3,600 psia and a skin factor of -1.0 , the maximum flow rate (STB/D) that will result in single-phase flow in the reservoir is most nearly:

- (A) 2,250
- (B) 2,480
- (C) 2,890
- (D) 3,260

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24. A 24-hour production test was obtained for a new oil well completed with 2 7/8-inch O.D., 6.5 lb/ft, EUE 8rd tubing. The following well and test information is available for analysis.

Well Data:

Well depth	6,500 ft
Casing setting depth	6,490 ft
Tubing setting depth	6,000 ft
Perforations (mid-perf)	6,075 ft

Reservoir Data:

Initial reservoir pressure	2,800 psia
Bubble point pressure	2,400 psia
Current reservoir pressure	2,200 psia

Production Test Data:

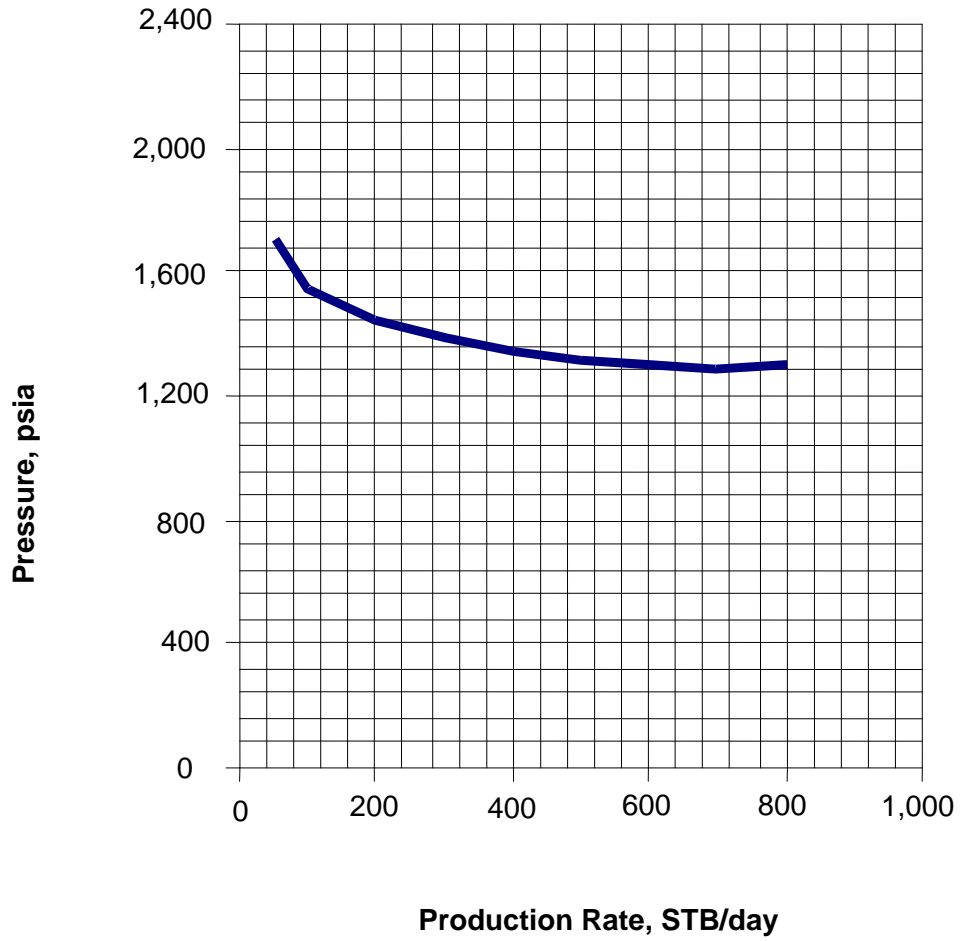
Oil production rate	420 bbl/d
Gas production rate	168 Mscf/d
Flowing bottomhole pressure	1,100 psia
Flow efficiency	0.70 (from pressure transient analysis)

Tubing intake data for 2 7/8-inch, 6.5-lb/ft, EUE 8rd tubing and a flowing wellhead pressure of 250 psia are given below and plotted on the graph on the opposite page.

<u>Oil Flow Rate, STB/D</u>	<u>Flowing Bottomhole Pressure, psia</u>
50	1,700
100	1,540
200	1,450
300	1,390
400	1,350
500	1,320
600	1,300
700	1,290
800	1,300

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TUBING INTAKE CURVE



If Vogel's inflow performance relationship (IPR) applies, the producing rate (STB/D) when the flowing wellhead pressure is 250 psia is most nearly:

- (A) 230
- (B) 330
- (C) 410
- (D) 580

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25. You have recently drilled and logged an exploratory well in a new basin. Based on the open-hole logs and a drillstem test, you suspect the prospective formation from 7,030 ft to 7,300 ft contains an oil/water contact. A repeat formation tester has been run and the following pressures were recorded:

<u>Depth, ft</u>	<u>Pressure, psi</u>
7,240	3,258
7,190	3,235
7,140	3,216
7,090	3,199
7,040	3,182

The sample chamber contained an insufficient amount of oil to determine its properties. The specific gravity of the water was measured to be 1.07.

The depth (ft) of the oil/water contact is most nearly:

- (A) 7,140
 - (B) 7,165
 - (C) 7,175
 - (D) 7,190
26. You have just drilled a well on the down-thrown side of a large fault to test whether the main producing interval in the field is productive on this side of the fault. The following parameters are known from the existing production in the field:

Water resistivity 0.018 ohm-meters
Invading fluid density 1.0 g/cm³
a = 0.625; m = 2.15; n = 2

If the porosity in the zone of interest is 9.4% and the true formation resistivity is 30 ohm-meters, the percent **hydrocarbon** saturation is most nearly:

- (A) 94
- (B) 87
- (C) 75
- (D) 25

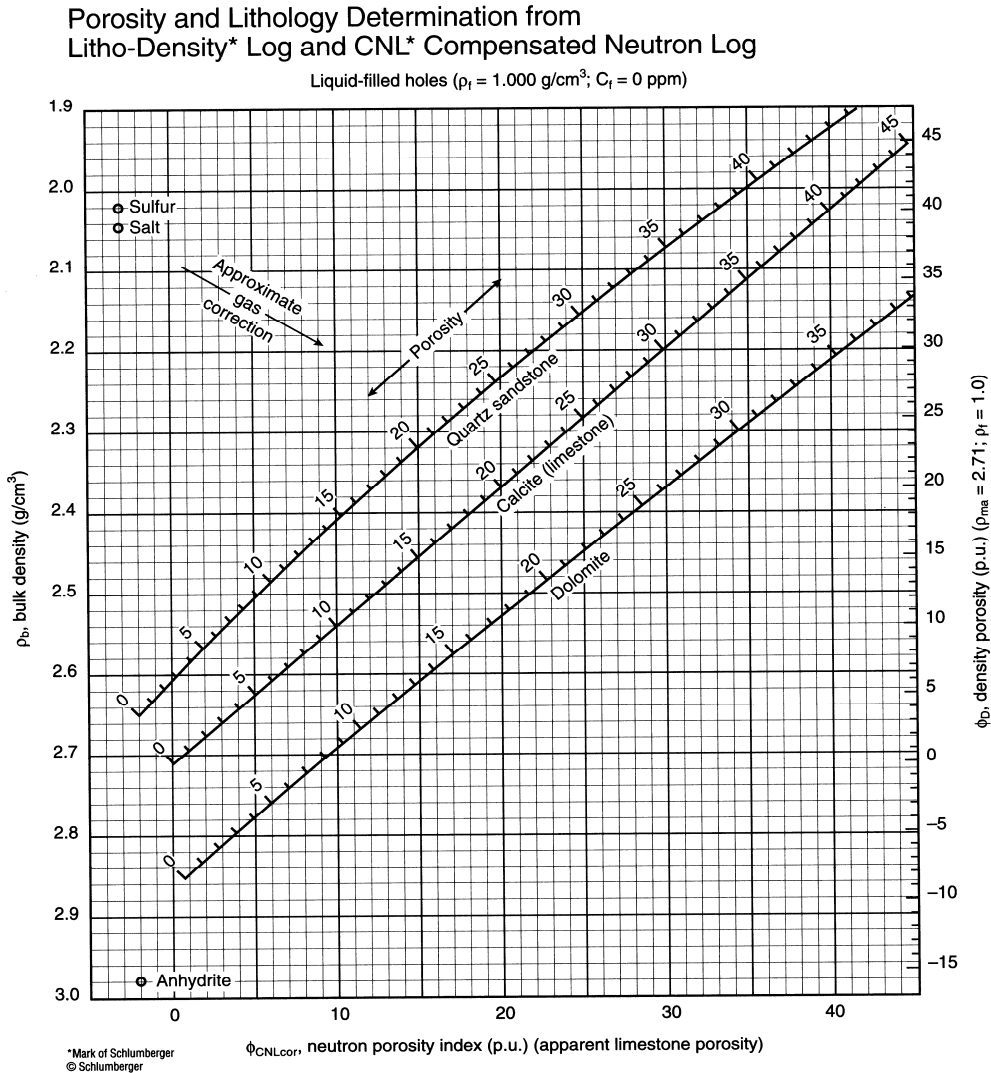
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27. You have recently drilled and logged a potentially productive zone from 10,020 ft to 10,040 ft. The following information has been relayed in from the field:

Formation Gas Bearing Sand
 Density porosity 14.8% (limestone base)
 Neutron porosity 4.8% (limestone base)
 Attached graph

The porosity (%) in the zone of interest is most nearly:

- (A) 9.8
- (B) 10.4
- (C) 12.6
- (D) 19.6



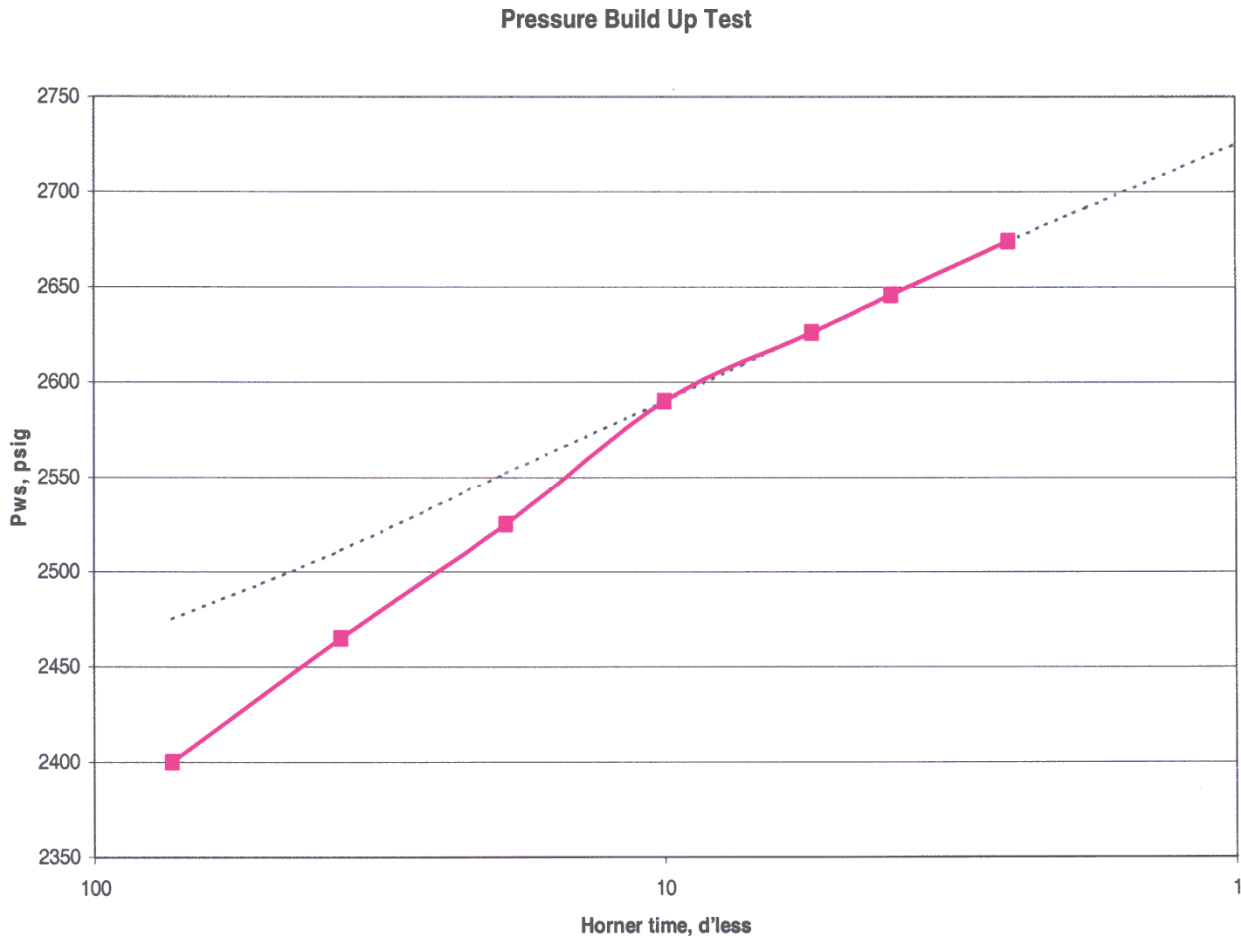
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28. A well produced for 3 days at 522 STB/D then shut-in for a pressure build up test. The following additional information is known:

- Bubble point pressure = 1,500 psi
- Net pay = 18 ft
- Wellbore radius = 0.40 ft
- Oil viscosity = 2 cp
- Total compressibility = 2.5×10^{-5}
- Formation Volume Factor = 1.21 res bbl/STB
- Permeability = 47 md
- Horner plot slope = 135 psi/cycle
- Flowing bottomhole pressure = 1,610 psi

Considering the above information and the figure provided (points are actual data), the skin value is most nearly:

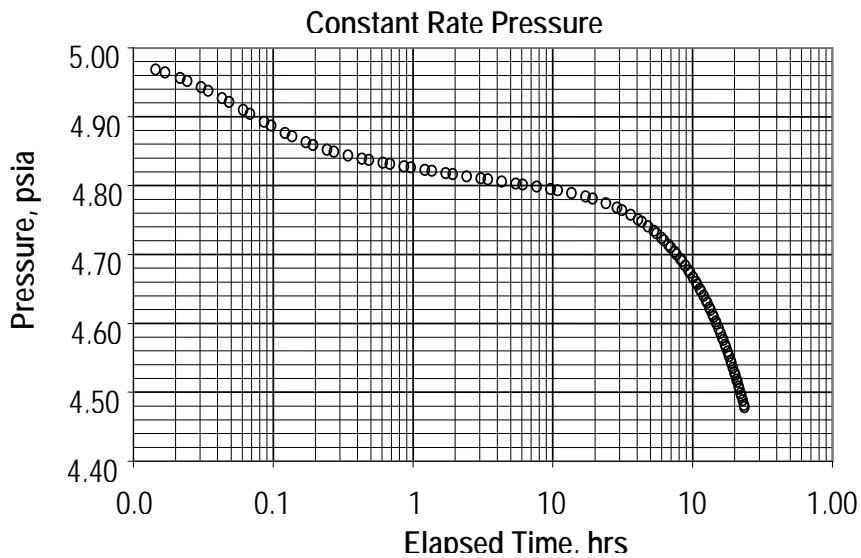
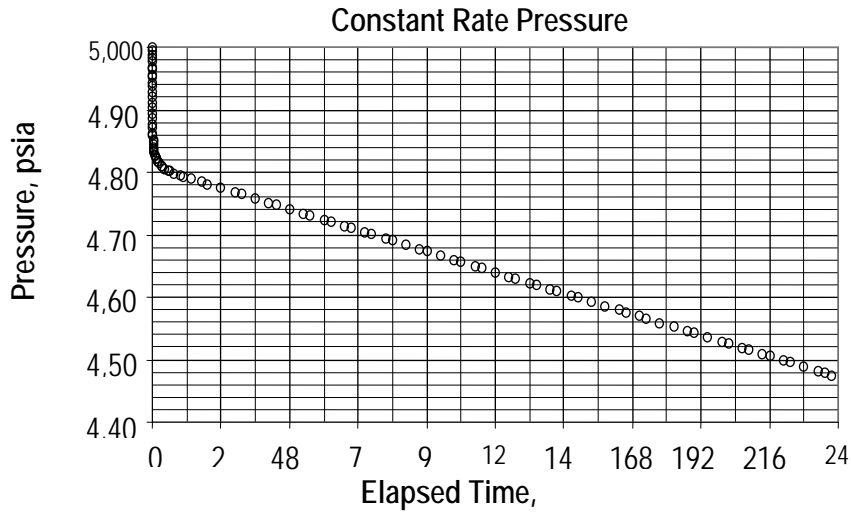
- (A) 2.6
- (B) 3.5
- (C) 5.1
- (D) 6.1



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29. The following information is available from a constant rate drawdown test as well as the attached pressure drawdown history plotted both in Cartesian coordinates and semi-logarithmically.

Total compressibility $5.00E-06 \text{ psi}^{-1}$
 Wellbore radius 0.25 ft
 Oil rate 425 STB/D
 Oil formation volume factor 1.26 res bbl/STB
 Homogeneous reservoir



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The connected reservoir pore volume (ft³) is most nearly:

- (A) 30,068
- (B) 696,001
- (C) 18,222,578
- (D) 182,225,782

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30. You have just drilled a well on the down-thrown side of a large fault to test whether the main producing interval in the field is productive on this side of the fault. The following parameters are known from the existing production in the field:

Water resistivity 0.018 ohm-meters
Invading fluid density 1.0 g/cm³
Oil formation volume factor 1.15 RB/STB
a = 0.625; m = 2.15; n = 2

If the porosity in the zone of interest is 9.4% and the true formation resistivity is 20 ohm-meters, the original oil in place (STB/ac-ft) is most nearly:

- (A) 444
(B) 510
(C) 1,228
(D) 2,866
31. A pressure buildup well test is to be designed for a bounded reservoir after a constant rate drawdown period. Assume a circular reservoir with the well located in the center and use an exact t_{DA} .

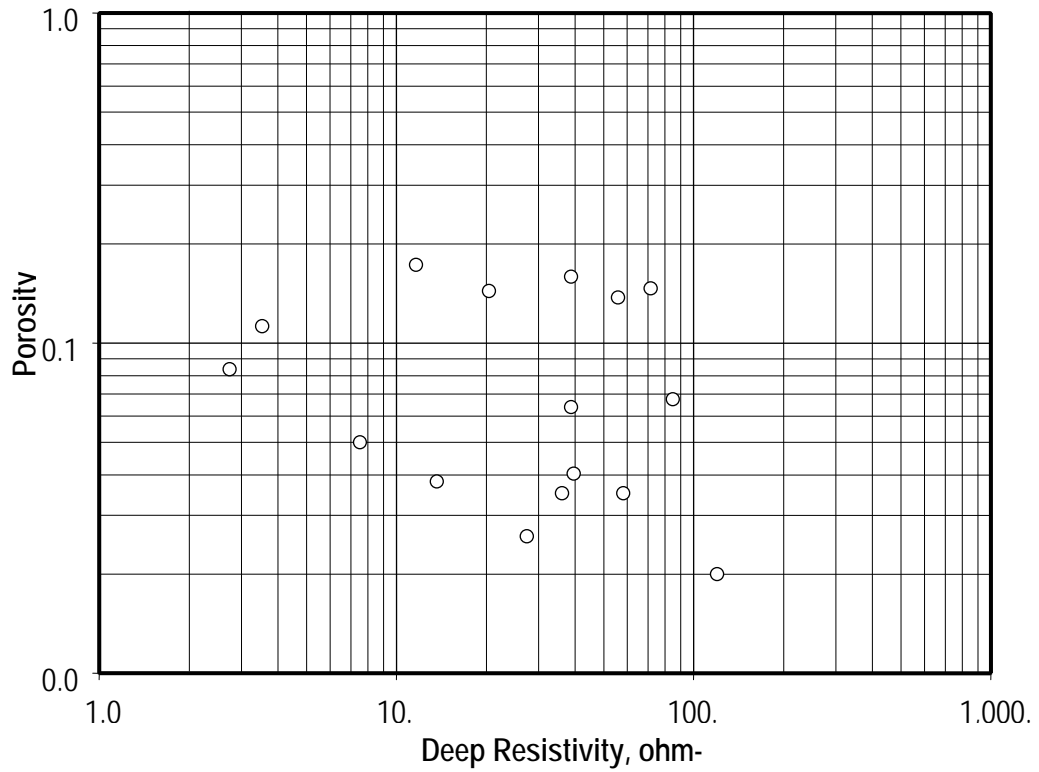
Reservoir thickness 31 ft
Total compressibility 6.00×10^{-5} psi⁻¹
Wellbore radius 0.25 ft
Porosity 15%
Oil formation volume factor 1.25 res bbl/STB
Permeability 100 md
Oil viscosity 8.2 cP
Constant production rate 107 BOPD, 0 BWPD
Estimated productive area 80 ac
Homogeneous reservoir

The estimated time (hours) when the pseudo-steady-state pressure response begins is most nearly:

- (A) 0.022
(B) 41.000
(C) 975.000
(D) 9,753.000

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32. The figure is a log-log plot of porosity versus resistivity, assuming $m = n$ and $a = 1$.



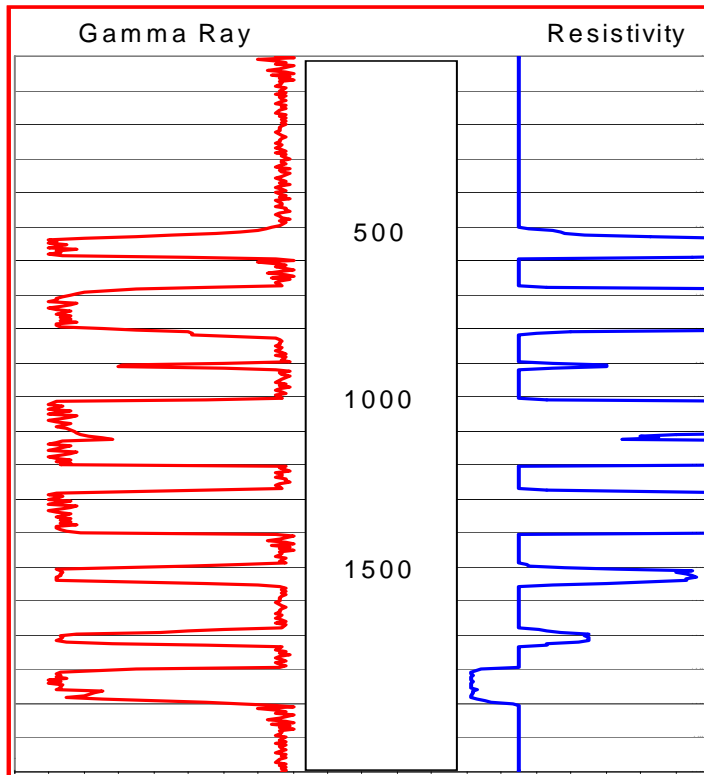
The value of R_w (ohm-meters) is most nearly:

- (A) 0.0020
- (B) 0.0033
- (C) 0.0200
- (D) 2.8000

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33. A well is being planned in an area that requires protection of shallow freshwater sands. Local regulations require the surface casing shoe to be at least 200 ft below the deepest freshwater sand above 1,500 ft and the top of the cement to be at least 100 ft above the shallowest freshwater sand. Use the following assumptions in your calculations.

A 20-inch hole will be drilled to the minimum depth required by regulation, and 16-inch casing (65 lbm/ft) will be run to TD. The open hole caliper logs from offset wells indicate 20% excess will be required in the cement volume to accommodate washouts. The float collar will be run 80 ft above the float shoe. Class C cement weighing 14.8 lbm/gal and having a yield of 1.32 ft³/sack will be used and circulated back to surface. Refer to the log strip shown below, which is a composite from offset wells, to evaluate the required casing depth.



The slurry volume needed (to the nearest sack) to protect fresh water according to regulatory guidelines is most nearly:

- (A) 1,029
- (B) 1,219
- (C) 1,576
- (D) 2,616

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34. The following information is provided regarding expected pressures for various hole intervals:

Interval	MD (feet)	TVD (feet)	Formation Pressure (psi)	Fracture Pressure (psi)
Surface	4,000	4,000	1,900	2,800
Intermediate	11,000	9,000	5,800	8,000
Production	15,000	12,000	10,000	11,300

A trip margin of 0.2 lbm/gal must be maintained during all intervals.

The minimum drilling fluid density required (to the nearest 0.1 lbm/gal) when the intermediate casing is run is most nearly:

- (A) 10.1
 - (B) 10.3
 - (C) 12.6
 - (D) 17.3
35. A well has a proposed kick-off point of 12,000 ft MD (12,000 ft TVD) with 0 degrees of deviation and with a final proposed total depth of 13,500 ft MD (12,100 ft TVD) at 90 degrees of deviation. The 90 degrees of deviation was initially achieved at 12,157 ft MD.

The directional drilling technique that most nearly addresses the desired wellbore trajectory is:

- (A) Short radius
 - (B) Medium radius
 - (C) Long radius
 - (D) Extended reach
36. A well was drilling ahead and experienced a fishing job. The daily cost of continued fishing operations is US\$11,500. The total cost of the fish, if left in the hole, is US\$165,000. Continued fishing operations have a 30% probability of success. The cost of sidetracking is estimated to be US\$250,000 with an assumed 100% probability of success.

To the nearest whole day, when is it more expensive to continue fishing operations on a risked dollar basis versus the cost of sidetracking?

- (A) 8
- (B) 11
- (C) 15
- (D) 22

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37. A well is drilled to a TD of 11,000 ft with 9.5-lbm/gal drilling fluid. Casing of 8 5/8-inch will be run with a required overpull allowance of 100,000 lb and a tension safety factor of 1.8. The following options exist in inventory for 8 5/8-inch casing with 11,000 ft available for each item.

Grade	Weight (lbm/ft)	Body Yield (1,000 lb)	Joint Strength (1,000 lb)		
			STC	LTC	BTC
K-55	32	503	402	452	690
\$/ft			16.26	16.69	17.89
K-55	36	568	468	526	780
\$/ft			18.39	18.70	20.04
N-80	36	785		688	895
\$/ft				28.54	30.57
N-80	40	925		788	1,001
\$/ft				31.71	33.97

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Based on tension design considerations only, the casing design that is most cost effective is most nearly:

- (A) 11,000 ft of 32 lbm/ft STC K-55
- (B) 11,000 ft of 32 lbm/ft LTC K-55
- (C) 11,000 ft of 36 lbm/ft BTC N-80
- (D) 11,000 ft of 40 lbm/ft BTC N-80

38. A well is drilling ahead and experiences a fishing job that results in the need to set a plug for sidetracking. A 2 3/8-inch fiberglass stinger is run in conjunction with the 5-inch drill pipe. A balanced plug is set and the hole is **NOT** kept full while pulling out of the cement plug with the stinger to minimize fluid disturbance.

The statement that most nearly describes a drawback in this balanced plug method is:

- (A) The drill pipe will typically pull dry.
 - (B) The fiberglass stinger allows the plug to remain drillable if the stinger becomes stuck.
 - (C) Contamination of the cement slurry with mud is minimized.
 - (D) The internal capacity and displacement volume difference between the drill pipe and the stinger is not accounted for.
39. A well is drilling ahead and enters a gas-bearing, permeable formation. A gas influx of a known size enters into the wellbore. Assume the influx is contiguous (no mixing with the drilling fluid) and no gas migration occurs. The measured depth equals the true vertical depth, the O.D. of the drill string is constant including the BHA, and the open hole O.D. and casing I.D. are equal. The volume of the influx is less than the annular volume between the open hole and drill string. The influx is circulated out using a constant, balanced bottomhole pressure method that allows no additional influx while circulating only original density drilling fluid.

The statement that is most correct in describing the expected **MAXIMUM** pressure at the casing shoe is:

- (Q) The maximum pressure occurs as the gas reaches the surface when the surface casing pressure is maximum.
- (R) The maximum pressure occurs when the gas bubble/drilling fluid interface is at the casing shoe.
- (S) The maximum pressure occurs when the gas column is at its minimum height during the initial shut-in of the well.
- (T) When the maximum pressure occurs is not predictable.

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40. A well is drilling ahead in a fluid-filled vertical hole where MD equals TVD and the drilling fluid density is >8.3 lbm/gal. The next bit run requires optimum hydraulics to minimize drilling costs. Two primary methods are available to optimize the bit hydraulics. Method 1 will optimize bit hydraulic horsepower, and Method 2 will optimize jet impact force. Assume that the surface pressure is the same for both methods, that adequate surface horsepower is available from the mud pumps for both methods, and that the optimum flow rate for both methods lies between the minimum acceptable annular velocity and the maximum acceptable annular velocity.

The statement that is most correct regarding the optimum flow rate is:

- (U) The optimum flow rate for both methods is the same since the surface pressure is the same.
- (V) The optimum flow rate for Method 1 will be greater than the optimum flow rate for Method 2.
- (W) The optimum flow rate will be greater for Method 1 50% of the time, and the remaining times will be greater for Method 2.
- (X) The optimum flow rate for Method 2 will be greater than the optimum flow rate for Method 1.

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Correct Answers to the Petroleum Engineering Afternoon Sample Exams

501	B
502	B
503	A
504	D
505	B
506	C
507	B
508	C
509	B
510	B
511	B
512	A
513	D
514	A
515	D
516	A
517	C
518	B
519	B
520	A

521	C
522	D
523	C
524	B
525	C
526	C
527	B
528	B
529	C
530	A
531	C
532	C
533	B
534	C
535	A
536	B
537	D
538	D
539	B
540	D