HANDBOOK OF

OIL & GAS OPERATIONS

"How to Reduce Exploration and Production Costs

and Save Money

Through Efficient Oil and Gas Operations"

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HANDBOOK OF OIL & GAS OPERATIONS

Volume I - Before Drilling
Volume II - Drilling
Volume III - Completion

How to Use this Book

The Handbook is divided into three very broad categories that encompass the sum of activity on the exploration and production side of the oil and gas industry: Before Drilling, Drilling, and Completion.

The Handbook assumes that the User is at least slightly familiar with the oil and gas business. It is designed to be used as a step-by-step reference to assist in walking through each particular situation, exposing any pitfalls in the planning stages of a project, and giving choices and alternatives at each decision-making juncture. It is also designed to be used as a quick reference and is set up in such a way as to afford quick access to the needed information.

The Handbook is written in bullet style and in an outline format, opting to get the point across without burdening the User with lengthy narrative regarding theory, derivations, etc.

At the beginning of each chapter there is a Table of Contents outline that gives the Major Subjects and Major Categories of each chapter. This snapshot of the chapter gives enough detail to allow swift access to the needed information.

The outline format facilitates speed and ease of use, and is used in each Volume as shown below.

Volume II - Drilling   Chapter 6 - Location Preparation

A- MAJOR SUBJECTS COVERED IN THIS CHAPTER

- **a- Major Categories in each of these subjects**
  - 1) Division
    - A) Sub Division
      - a) Group
        - 1. Category
          - A. Sub Category
            - a. Unit
              - 1] other
                - A] detailed
                  - a] information

Note:

- + is a plus sign
- ÷ is a divided-by sign
- { } indicates a reference

Volume II - Drilling

6 - LOCATION PREPARATION

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A- GENERAL

a- Before Surveying

1) What section/survey will the well be located in?
   A) If the location is based on key wells, tie in these wells and show them on the plat, map scale permitting.
   B) If old wells are located close to the primary site, tie in these wells also.
      a) If time and money permit, get their ground elevations.
   C) How deep is the clay in the area?
   D) What is the soil profile?
2) How many acres are in the drill site tract?
   A) Does the Operator have all of the tract under lease?
   B) Based on the projected depth of the well, estimate how many acres the location will cover. [**C-**]
3) What are the calls (perpendicular measurements to the lease lines and survey lines)?
4) Get exact directions to the location from all directions.
5) Who are the Surface and Mineral Owners?
   A) List each one's name, address and phone number.
6) Which other Operators have a mineral interest on the tract or in the area?
   A) List each one's name, address and phone number.
   B) Call the other Operators who have a mineral interest in the lease, either shallow or deep rights, and inform them that the well is being staked.
7) What is the name and phone number of the Lawyer who performed the Title Opinion?
8) Find out from your attorneys or read the lease to determine what the specific provisions are within the Oil and Gas Mineral Lease (O&GML) concerning the Operator's obligations to the Landowner regarding resulting surface damages when access to the drill site and the actual drill site are built.
   A) Under what conditions are damages due?
   B) If the Landowner rates damages or consideration, how are they to be handled?
   C) Have damages already been paid?
9) May the Operator land farm (spread on site) the drilling fluids at the completion of drilling activity?
   A) If allowed, under what conditions?
10) Contact the Surveyor.
   A) Take a copy of the property description portion of the O&GML to the Surveyor Party Chief.
      a) If it has a meets and bounds description, it will save them record search time at the courthouse.
      b) If the lease does not have a meets and bounds description of the lease, the Party Chief will need to know the volume and page number of the record that contains it.
   B) Set a date to stake the well.

b- Notify the Landowner

1) Call or write (return receipt requested) the Landowner.
   A) Arrange to meet with the Landowner at least one week before your meeting with the Location Contractors.
      a) A convenient time is usually when the Surveyors initially go out on the lease to stake the location.
   B) Surveyors will be staking the well site on (*00 - 00 - 00*).
   C) Follow-on operations will probably occur within (*time frame*).

c- Meet with the Landowner

1) Based on the estimated depth of the well, the location will cover approximately (#) acres.
2) What is the drainage pattern in the area of the drill site?
    - A) Is drainage good at the location?
        - a) If not, the location costs will be higher.
3) Is there any need for fencing material while the well is being drilled?
    - A) If we take it down, does the Landowner want the fencing material?
4) Does the Landowner want the water well left for use after drilling operations are finished?
    - A) Check with State regulations to see if they require the Operator to transfer the obligation to plug the water well to the Landowner via a signed affidavit.
5) Does the Landowner already have a water well that could be used?
    - A) Does it produce in the volume that the rig requires?
    - B) Will the Landowner sell you the water?
6) If the well is a dry hole:
    - A) does the Landowner want the well for use as another water well?
    - B) does the Landowner want the entrance removed or left in place?
7) Reconfirm that the drilling mud (*may/may not*) be spread out on the property at the conclusion of drilling activity.

d- Stake the Well

1) Be prepared to stake alternate locations, based on the primary site, with respect to:
    - A) permanent structures.
    - B) roads.
    - C) property lines.
    - D) drainage patterns.
    - E) low lying areas.
    - F) hostile landowners.
2) Can the drilling rig get into the location without problems?
    - A) If not, identify an alternate route.

e- Meet with Contractors and Landowner

1) Set a date and time to meet with the Location Contractor, Drilling Contractor and Landowner.
2) If a combination lock is to be used, pass out the combination.
3) What is the expected spud date?
4) Is a Rig plat available?
5) Do all of the bidders have the Operator's address and phone number?
    - A) Bid all work but keep the pits separate in case the Drilling Contractor can get it done cheaper on a Footage Contract.
6) How do you want the pits laid out?
    - A) Put the pits on the low side of the location.
    - B) What size reserve pit is required? **[Chapter 7, C-, c-, 2) and 10)]**
        - a) 100 feet x 100 feet for a 6,000 foot well is normal.
7) Is a permit required for the water well?
8) Entrance
    - A) If livestock need to be kept in, put up a gate, a cattle guard or a gap.
    - B) If there are any ditches to cross at the road, allow for:
        - a) a 60 foot winged-in fence and entrance (if the road is narrow).
            1. Use 10 foot corner posts and 8 foot brace posts.
            2. All other posts normally have 6 inch tops.
            3. If a gate is required, use a 16 foot galvanized aluminum gate.
            4. Secure with a 4 foot chain and a combination lock.
        - b) a long culvert.
            1. Normally lay a 15 inch pipe at the crossing.
            2. If large amounts of water will be drained during heavy rains, this will suffice.
        - c) material to cover the culvert.

9) Does either the road to the location or the location itself require gravel?
   A) 6 inch compacted gravel usually works the best.
10) Are there any gas lines in the area or buried telephone cables (usually found along the roads) that may be adjacent to the property?
   A) Call the companies prior to doing any work and have them:
      a) send a representative out to the field to meet with the Contractor doing the dirt work.
      b) send a crew out to flag the lines.
11) Keep track of the topsoil so that, after cleaning up, the topsoil can be put back into place.

B- BOARD LOCATIONS

a- Additional Information

1) Estimate the length of time you need the boards: 30, 45, 60, or 90 days.
   A) Will work be done in the rainy season?
   B) Approximately how long will the drilling rig be on location?
   C) Are the boards needed for completion?
2) Entrance
   A) Do you need a 15 inch drainage pipe in the ditch at the entrance?
      a) How much material (gravel, fill dirt, etc.) is needed to fill in the gap between the pipe and the boards?
   B) How big of a wing-in do you need (usually 70 feet)?
   C) What is the distance from the entrance to the location?
3) Construction
   A) Do you need any drainage pipe(s) under the boards between the road and the location?
   B) Do you want plastic laid down on the ground before the boards are placed on top?
      a) This is a highly recommended practice.
      b) Putting fiber or plastic sheets under the boards will:
         1. make cleanup easier.
         2. protect the ground underneath.
         3. keep wet spots from leaking upward, making a hole that will let the location sink and allow the boards to break under traffic.
   C) How do you want the boards constructed?
      a) usually 3-ply
      b) Mats (pre-fabricated board sections) are gaining wide acceptance.
   D) If the road is lengthy between the entrance and the location, try to include an area large enough for a vehicle to turn around.
      a) At a minimum, there should be a turnaround at the drill site.
      b) Leave an extra bundle of boards at the turnaround.
4) Drill Site
   A) Do you need to board up the cellar and ditches?
   B) Leave extra boards for the rig to level up with.
      a) 3 bundles
5) Does the Drilling Contractor dig reserve, trash, shale, and water pits?
6) Do you want a ring levy around the location?
   A) usually 2 feet high

C- LOCATION SIZES

a- Before Clearing the Location

1) Will you be allowed to spread (land farm) the mud?
   A) If you can, you will be spreading the mud about 3 inches thick; 4 inches at the most.
2) Keep in mind that you will usually need 4 times the depth (in feet) of the fluid remaining in the reserve pit *times* the area of the reserve pit in order to approximate the size of the area that the contents of the reserve pit will cover when it is spread out.
3) This needs to take place in a cleared spot.

b- Well Depth vs. Location Size

1) Although location size will depend entirely on the drilling rig and the Drilling Contractor's specifications, a general relationship between well depth and location size is:

Well Depth	Cleared Area	# of Acres
0' - 2,000'	200' x 250'	1.15
2,000' - 4,000'	250' x 250'	1.44
4,000' - 6,000'	250' x 300'	1.72
6,000' - 8,000'	310' x 260'	1.85
8,000' - 10,000'	310' x 315'	2.15
10,000' - 12,000'	310' x 370'	2.63
12,000' - 14,000'	310' x 380'	2.70
14,000' - 16,000'	320' x 410'	3.01
16,000' - 25,000'	335' x 435'	3.35

D- CALCULATIONS

a- Linear Foot

1) A linear foot on a board road is equal to 12 ft^2.

b- Truck Capacity

1) Since many state and local laws dictate how much material can be hauled on one truck, due to road weight and load limits, material is normally sold by the ton.
2) A standard dump truck with a single axle has a capacity of 5 to 6 cubic yards of material when loaded water-level.
   A) Its average weight load of material is approximately 6 tons.
      a) This will still be within legal limits in most cases.
3) A dump truck with a tandem-type axle has a capacity of 10 to 14 cubic yards of material when loaded water-level.
   A) Its average weight load of material is approximately 13 tons.
      a) This will still be within legal limits in most cases.
4) An 18-wheeler dump truck has a capacity of 16 to 24 cubic yards of material when loaded water-level.
   A) Its average weight load of material is approximately 21 tons.
      a) This will still be within legal limits in most cases.

c- One Cubic Yard of Material

1) One cubic yard = @ 1.13 tons
2) One cubic yard = 3' x 3' x 3' = 27 ft^3
3) One cubic yard of material equals approximately 6 inches of compacted material along an approximately 4 foot length of a 14 foot wide road.

d- Material per Linear Unit of Road Length

1) Use the schedule below to find the appropriate coefficient needed to estimate the quantity (in cubic yards) of *processed* gravel or crushed rock required per linear unit of road length.
2) Coefficient for use in the calculations:

Width (feet)	Thickness (inches)	Condition*	Length of Road Section 100ft	100yds	1 mile
10	1	loose	3.09	9.26	162.9
10	1	compact	3.86	11.57	203.6

   A) *The ratio of loose thickness to compacted thickness is assumed to be 1.25.
   B) The way a material compacts will be a function of the material.
      a) If the material contains a lot of clay or silt, it will compact differently than material that has the clay and silt processed out.

3) **The quantity of material required = the road length coefficient X the road width correction factor X the road thickness correction factor X the road length correction factor**

   A) Example - Calculate the quantity (in cubic yards) of *processed* gravel or crushed rock required for 4 inches compacted on 350 yards of road, 22 feet wide.

      a) On the compacted material row, read the 100 yards of road length column coefficient of 11.57.

      b) Since the schedule is based on 10 feet of road width and the example calls for 22 feet, this figure has to be factored up to size by dividing 22 by 10 to get the road width correction factor.

      c) Since the schedule is based on 1 inch of compacted road thickness and the example calls for 4 inches, this figure has to be factored up to size by dividing 4 by 1 to get the road thickness correction factor.

      d) Since the schedule is based on 100 yards of road length and the example calls for 350 yards, this figure has to be factored up to size by dividing 350 by 100 to get the road length correction factor.

   B) Therefore:

      Q = 11.57 x [22 ÷ 10] x [4 ÷ 1] x [350 ÷ 100] = 356.4 yds^3

e- Road Length of Spread

1) Calculate the truck capacity in cubic yards per linear feet of spread of *processed* gravel or crushed rock needed to produce the required thickness along a road of a certain width.

Surface		**Width of Roadway**		
Thickness	**Condition**	12ft	22ft	30ft
1in	loose	27.0	14.7	10.8
	compact	21.6	11.8	8.6
3in	loose	9.0	4.9	3.6
	compact	7.2	3.9	2.9
4in	loose	6.7	3.4	2.7
	compact	5.4	2.9	2.1
6in	loose	4.5	2.4	1.8
	compact	3.6	1.9	1.4

linear feet per cubic yard of material

2) Example - Calculate the road length of spread for a 5 cubic yard truck to produce a 4 inch compacted thickness, 22 feet wide.

   L = 5.0 x 2.9 = 14.5'

   A) Where:

      5.0 = the truck capacity in cubic yards

      2.9 = linear feet per cubic yard of material compacted to 4 inches of thickness along a roadway that is 22 feet wide

f- Number of Truck Loads Required

1) Example - Using the above 14.5ft of road length of spread.

   Road Length ÷ Road Length of Spread =

   Number of Truck Loads Required

7 - DRILLING

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DRILLING

A- GENERAL

a- Common Specifications in Drilling Contracts

1) Depth in feet
2) Commencement date
3) Formations to be penetrated
4) Hole size
5) Casing sizes to designated depths
6) Drilling mud properties
7) Logging program
8) Cementing program
9) Type of testing
10) Well completion program
11) Size, weight and grade of drill collars
12) Hole deviation restrictions
    A) More emphasis should be placed on the *rate* of hole angle change than on the maximum hole angle.

b- Types of Drilling Contracts { 32, 42 }

1) Turnkey Drilling Contract

A) It requires the Operator to pay a stipulated amount to the Drilling Contractor upon meeting contract specifications.

B) The Drilling Contractor:
   a) provides all of the labor.
   b) furnishes most of the material (contract specific).
   c) controls the entire drilling operation independent of any supervision by the Operator.

C) Provisions Common to Most Turnkey Contracts
   a) Location of well
   b) Commencement date
      1. given as on (*date*) or by (*date*)
   c) Adequate location
      1. roads that provide access to the location
   d) Conductor pipe
      1. should be arranged for and set by the Drilling Contractor
   e) Contract depth
      1. given as depth to which the Drilling Contractor should drill
   f) Hole sizes
      1. includes the surface hole
   g) Price
      1. includes these items usually furnished by the Drilling Contractor
         A. Bits
         B. Water
         C. Fuel
         D. Surface pipe, and Intermediate pipe if required
            a. clearly defined size, weight and grade
               1] API or non-API
               2] new, or if used, tested to (*#*) psi
            b. cement (with additives)
            c. cement services
            d. maximum number of hours to wait before nippling-up (i.e. - set slips, cut off casing, etc.) operations are started
         E. Mud and chemicals
            a. according to a mud program included in the contract
            b. Specify who owns the mud at contract depth.
         F. Log type and Service Company
         G. All mobilization charges
            a. move in
            b. rig up
            c. rig down
            d. move out

- H. Drilling the rat hole and mouse hole
- I. Cost of well control insurance
  - a. certificate

h) Straight hole specifications (e.g.)
  1. Limit to hole deviation per 100 feet
     A. usually 3 degrees or less
  2. Total allowed deviation
     A. usually 5 degrees or less
  3. How frequently the Drilling Contractor should survey the hole deviation
     A. at least every 500 feet

i) Clearly define when Daywork begins and ends (e.g.).
  1. Daywork begins when:
     A. a readable log is furnished to the Operator.
     B. drilling reaches a certain depth.
     C. drilling reaches a certain zone by cuttings, etc..
     D. special operations such as drill stem testing and coring are done.
  2. Daywork ends when:
     A. blow-out preventers (BOPs) are nippled-down.
     B. the tanks are cleaned.
     C. the drill pipe is laid down.

j) A clearly defined deadline as to when payment is due
  1. This is normally handled through an escrow account at a bank that both the Operator and the Drilling Contractor agree to use.
     A. a three-way agreement with the bank
  2. The total Turnkey cost is held in an interest-bearing account.
     A. The Operator receives the interest money.
  3. All parties concerned sign a letter which spells out:
     A. the release of the contents of the account.
     B. other provisions of the terms of the agreement.

k) The Drilling Contractor is usually required to furnish evidence that all third-party bills are paid in full.

2) Footage Drilling Contract

A) There is an agreed-upon dollar rate per foot drilled.
  a) This often ensures speedy completion of the well because it is to the advantage of the Drilling Contractor to finish the job quickly.

B) The "Daywork" portion of the Footage Contract pays the Drilling Contractor for days when drilling is suspended and payment cannot be made under a Footage Contract.
  a) Dayrate payment is usually:
     1. written into the Drilling Contract.
     2. signed by both parties.
     3. covers situations in which the drilling rig is on site, performing essential but non-drilling operations.
        A. Such activities might include using the drilling rig to:
           a. shoot cores.
           b. log the well.
           c. complete other activities necessary to the Operator but not compensated for in the Footage Drilling Contract.

C) Provisions Common to Most Footage Contracts
  a) Location of well
  b) Commencement date
     1. given as on (*date*) or by (*date*)
  c) Depth
     1. Footage depth
        A. All other drilling is done on a Daywork basis.
     2. Maximum depth to which the Contractor will be required to drill

d) Rates
1. Footage rate
2. Daywork rate
A. with drill pipe
B. without drill pipe
C. using the Operator's drill pipe
3. Crew sizes
A. Rates quoted should be for a standard minimum crew size.
4. Work stoppage rate
A. per day
B. per hour
C. when it applies (e.g.)
a. conditions of force majeure
b. inadequate surface conditions because of the Operator's failure to maintain the location
c. the rig is released but cannot be moved because of surface conditions
5. Repair time rate
A. number of hours for a breakdown
B. number of hours cumulative
6. Stand-by rate (e.g.)
A. waiting on orders (WOO) with crew
7. Reimbursable costs
A. actual costs plus handling charges
8. Rate revision conditions

e) Time of payment provisions

f) Work stoppage conditions
1. By the Operator
A. anytime
a. Payment for the entire job may be due.
2. By the Drilling Contractor
A. when the Operator becomes insolvent
3. Work stoppage compensation
A. The Operator is usually required to pay a certain amount of money regardless of when the work stoppage occurs or what the conditions are.

g) Casing program
1. specified by the Operator

h) Drilling methods and practices
1. If no mud program is attached to the Footage Contract, the Drilling Contractor has the right to determine it.
2. Blow-out preventers (BOPs) are to be maintained in good condition by the Drilling Contractor.
3. hole deviation restrictions
4. a list of equipment to be used

i) Handling formations that are difficult or hazardous to drill
1. To qualify under this provision the Drilling Contractor's 24 hour drilling progress multiplied by the Footage rate does not equal the Daywork rate plus the cost of the bits.
2. This condition (e.g. - very slow drilling or stuck pipe) is charged as Daywork.
3. Situations where this commonly occurs
A. water flows
B. dome structures
C. steep dips
D. highly faulted areas
E. abnormal formation pressure
4. The Drilling Contractor will fight circulation loss for (#) hours, after which time Daywork rates will be used.
A. The total number of hours lost under this provision will usually not exceed (#) hours for the entire job.

5. "Gulf Coast" Clause (optional, as needed)
   A. This clause requires the rig to go on Dayrates if:
      a. the mud weight has to be raised to a certain point (usually 12.5 ppg).
      b. the mud weight has to be raised one pound higher than what was expected at total depth (TD).

j) Daily reports will be kept on International Association of Drilling Contractors-American Petroleum Institute (IADC-API) forms.
   1. The Drilling Contractor will supply a copy to the Operator.

k) Clearly state the minimum amount and type of insurance that must be carried by the Drilling Contractor.
   1. include blow-out insurance.

l) Responsibility for loss or damage
   1. While on Footage, the Drilling Contractor is responsible for all of the equipment.
   2. While on Daywork, the Operator usually assumes responsibility for all of the equipment.
   3. If the hole is lost due to:
      A. Contractor negligence, the Drilling Contractor is usually required to drill another hole.
      B. Operator negligence due to design failures, the Drilling Contractor will be compensated as if the job was completed.

m) If confidentiality is desired concerning the information from the well, it must be requested of the Contractor by the Operator.

3) Daywork Drilling Contract

A) This type of contract usually requires the Drilling Contractor to furnish equipment and perform services as provided for in the Daywork Contract for a specified sum of money per day under the direction, supervision and control of the Operator.

B) The Operator is solely responsible and assumes liability for all consequences of operations by both parties while on a Daywork basis, including results and all other risks or liabilities.

C) Provisions Common to Most Daywork Contracts
   a) Location of well
   b) Commencement date
      1. given as on (*date*) or by (*date*)
   c) Depth
      1. approximate depth or formation top
      2. maximum depth to which the Contractor will be required to drill
   d) Rates
      1. All mobilization charges
         A. move in
         B. rig up
         C. rig down
         D. move out
      2. Daywork rate
         A. with drill pipe
         B. without drill pipe
         C. using the Operator's drill pipe
         D. charges
            a. Drill pipe is considered to be in use:
               1] when it is in the hole.
               2] while it is being laid down.
            b. Drill pipe is considered not in use when standing in the derrick.
            c. Portions of hours will not usually be charged.
      3. Crew sizes
         A. Rates quoted should be for a minimum standard crew size.
      4. Force majeure rate
      5. Repair time rate
         A. number of hours for a breakdown
         B. number of hours cumulative

6. Stand-by rate (e.g.)
   A. waiting on orders with crew
7. Reimbursable costs
   A. actual costs plus handling charges
8. Rate revision conditions

e) Time of payment provisions

f) Work stoppage conditions
1. By the Operator
   A. anytime
      a. Payment for the entire job may be due.
2. By the Drilling Contractor
   A. when the Operator becomes insolvent
3. Work stoppage compensation
   A. The Operator is usually required to pay a certain amount of money regardless of when the work stoppage occurs or what the conditions are.

g) Casing program
1. specified by the Operator

h) Drilling methods and practices
1. The Drilling Contractor will:
   A. except on a Daywork contract, follow the specifications outlined in the mud program.
   B. maintain the BOPs in good condition.
   C. clearly specify:
      a. hole deviation restrictions.
      b. a list of the equipment to be used.

i) Daily reports will be kept on IADC-API forms.
1. The Drilling Contractor will supply a copy to the Operator.

j) The Operator will maintain a sound:
1. location.
2. road.
3. entrance.

k) Clearly state the minimum amount and type of insurance that must be carried by the Drilling Contractor.
1. include blow-out insurance

l) Responsibility for loss or damage
1. While on Daywork, the Operator usually assumes responsibility for all of the equipment.
2. If the hole is lost due to:
   A. Contractor negligence, the Operator is responsible.
   B. Operator negligence due to design failures, the Contractor will be compensated as if the job was completed.

m) If confidentiality is desired concerning the information from the well, it must be requested of the Contractor by the Operator.

4) Combination Drilling Contract

A) The basis for payment is often combined in the final agreement.
   a) An Operator may agree to pay Footage rate to a certain depth, then pay Daywork for any drilling done below that depth.

B) A common clause establishes a "standby rate" which pays the Drilling Contractor for days when the rig is on the site but no drilling takes place.
   a) This situation could occur when the Contractor is waiting for:
      1. permission from the Operator to start testing.
      2. arrival of necessary equipment or supplies.
      3. muddy roads to become passable.

C) The Operator and the Drilling Contractor should agree on the:
   a) ability of both the men and the equipment to do the work properly.
   b) time required for completing the job.
   c) safety rules throughout the operation for:
      1. equipment.
      2. property.
      3. personnel.

5) **Advantages and Disadvantages** of each type of contract
   A) Footage
      a) Advantages
         1. The job is completed in less time.
      b) Disadvantages
         1. The cost of time to solve most problems is charged against the Operator.
   B) Turnkey
      a) Advantages
         1. There is no risk to the Operator.
      b) Disadvantages
         1. A lien can be placed on the well if the Drilling Contractor cannot pay the third-party charges.
         2. The Operator is ultimately responsible to the Regulatory Authorities.
   C) Daywork
      a) Advantages
         1. The Operator has complete control.
      b) Disadvantages
         1. The Operator has to have a representative on location at all times.
         2. The Operator assumes all of the risks of drilling the well.

c- Rig Selection {43}

1) Criteria for Rig Selection
   A) Financial stability of the Drilling Contractor
   B) Quality of supervision and rig personnel
   C) Hydraulic horsepower requirements
   D) Drill string requirements
      a) emphasis on hydraulics
   E) Requirements for adequate mud handling
   F) Rotary speed requirements
   G) Derrick and load requirements
      a) casing and drill string
   H) Well control equipment requirements
2) Other Criteria
   A) Overall mechanical suitability
   B) Capital costs or contractual rate
   C) Mobility
   D) Dependability
   E) Ease of operation
   F) Past performance of the rig under consideration
   G) Actual appraisal after rig inspection
      a) preferably during a drilling operation
   H) Type of formations to be drilled versus type of formations that the rig is accustomed to drilling
   I) Hole and casing program (straight or deviated) as compared to the rig's ability to handle it
   J) Auxiliary equipment required to complete the job compared to what equipment the rig crews are familiar with

d- Rig Moves

1) If the Landowner rates such consideration, settle damages first.
2) Prior to the Rig Move
   A) To save time and money, have a crew with a smaller rig:
      a) drill and set the conductor pipe.
         1. This provides a pilot hole for the big rig.
      b) dig out and reinforce the cellar.
      c) drill the rat hole and the mouse hole.
3) If it is a heavy rig, will the county roads need boards?
   A) If it will travel on roads that might not hold up, get a representative from the County out there to witness the move.

B) Document before and after conditions as much as possible.
a) Take pictures of the road before and after.
b) Get the pictures notarized.

4) Pre-mark equipment positions so that the truck drivers can see where to put things.

5) Have two rig crews on hand to:
A) connect the mud pumps.
B) spot and hook up the tanks.
C) hook up the cables.
D) help get the derrick in the air.

6) Rig moves are either:
A) regulated.
a) a major road is either crossed or traveled with over-sized loads
B) un-regulated.
a) a move made in the field (field move) or one where no major roads are crossed

7) To make rig moves as economical as possible the Drilling Contractor has to follow a detailed and organized load plan.
A) The load plan is:
a) dictated by priority of work.
b) managed by order of arrival.
B) The components of the load plan are governed by weight distribution.
a) Weight distribution is regulated by permit loads.
b) Loads that require permits can be:
1. daylight only moves.
2. weekend moves.

e- Rotary Rig Components {44}

1) Rotating System
A) Bit
B) Bit subs
C) Drill collars
D) Drill pipe
E) Kelly
F) Kelly cock
a) valve used to prevent or shut off backflow
G) Swivel
H) Rotary
I) Prime movers and compound

2) Circulating System
A) Bit sub
B) Drill collars
C) Drill pipe
D) Kelly
E) Rotary hose and standpipe
F) Swivel
G) Prime movers and compound
H) Mud pump
I) Mud pit

3) Hoisting System
A) Hook
a) attaches the kelly during drilling
B) Traveling block
a) raises and lowers the hook
C) Drilling line
a) wire rope that ranges in size from $1\frac{3}{8}$ to $1\frac{1}{2}$ inches in diameter
b) When a line has moved a ton of load over a distance of one mile, this equals one tonmile.
c) Tonmile records are kept at the rig.

D) Crown block
   a) The number of sheaves (grooves) used in a crown block is always greater than the number used on the traveling block.
   b) located in the crown of the derrick
E) Draw works
   a) consists of a revolving drum around which the drilling line is wound, and a series of shafts, clutches, chains and gear drives for speed changes and reverse
   b) also houses the main brake
F) Prime movers and compound
G) Mast (or derrick)
   a) supports the hoisting, rotary, and circulation systems
   b) rated by the:
      1. vertical load it carries
      2. wind load it can withstand from the side
         A. Most can stand a wind load of 100 - 130 mph with racks full of pipe.
   c) capacity ranges from 250,000 - 2,000,000 pounds
H) Substructure
   a) supports the mast
   b) rated by the load that it will support

4) Power System
   A) Power requirements vary for different drilling jobs.
   B) Most rigs require 1,000 - 3,000 horsepower (HP).
      a) provided by one or more engines
      b) depends on well depth and rig design
   C) For hoisting and circulation:
      a) shallow or moderate depth drilling rigs need 500 - 1,000 HP.
      b) heavy-duty rigs for 20,000 foot holes usually need 3,000 HP.
   D) Auxiliary power requirements for lighting, etc., may be 100 - 500 HP.
   E) Diesel or gas engines are usually the main power sources.
      a) Power is transmitted mechanically from engines through clutches to a unit called a compound, which in turn delivers power through chain drives to the draw works, rotary and usually (via belt drives) to the pumps.
      b) Torque converters or hydraulic couplings are frequently employed in newer drilling rigs.
      c) Diesel-electric power units generate and deliver electric current through cables to electrical switch gears, then to electric motors attached directly to the equipment involved.
         1. draw works
         2. rotary
         3. table
         4. mud pumps

f- Designing a Hydraulics Program { 45 }

1) General
   A) Hydraulics is one of many factors affecting the performance of the bit.
   B) Drilling hydraulics considers the performance of the circulating system and its ability to clean and carry cuttings out of the hole.
   C) Because of the small spaces within the pipe system, friction develops which restricts the movement of fluid.
      a) Factors which affect this resistance and the pressure required to push fluid through the system are:
         1. flow rate
            A. If flow rate is increased in a circulation system, more resistance to flow is developed.
               a. More pressure is required to move the fluid at a given flow rate.

2. flow area
   A. If flow area or pipe size is reduced while pumping fluid at a given rate, there is more resistance.
      a. More pressure is required to move the fluid at a given flow rate.
3. length of the system
   A. If the length of the system is increased, resistance to flow is increased.
      a. More pressure is required to move the fluid at a given flow rate.
4. fluid properties
   A. If the weight of the drilling fluid is increased, there is more resistance to flow.
      a. More pressure is required to move the fluid at a given flow rate.
   B. As the viscosity of the fluid is increased, there is more resistance to flow.
      a. More pressure is required to move the fluid at a given flow rate.
   C. If the annular velocity is high enough near the drill pipe to effectively remove cuttings from the hole, it will be high enough near the tool joints and drill collars.
      a. Actual experience in a particular area will tell you what annular velocity is best for the well.
      b. If not, it can be calculated based on the mud properties by the Mud Engineer.
      c. Many times, the extremely high velocities around larger components of the drill string (i.e. - collars, heavy weight pipe, stabilizers, etc.) is overlooked, and it is in these high velocity regions that most of the hole damage occurs.
         1] One of the goals in downhole rheology (fluid flow behavior) design is either turbulent or laminar flow.
         2] This is controlled and optimized by hydraulic horsepower or pressure drops at the bit.
         3] Laminar flow (a swift movement of fluid without the tumble of turbulence) is generally best for preventing erosion.
      d. The minimum but adequate calculated annular velocity should reflect the:
         1] expected penetration rate.
         2] carrying capacity of the drilling fluid.
            A] weight
            B] viscosity
            C] type of flow pattern
         3] actual hole caliper.
      e. This is normally best accomplished by trial and error, and/or experience.

D) Gather the following information.
   a) Contractor and rig number
   b) County and location
   c) Hole size
   d) Interval to be covered by the hydraulics program
   e) Mud weights desired at each depth
   f) Mud rheology
   g) Are high plastic viscosities planned?
   h) Pumps
      1. manufacturer
      2. model
      3. type
      4. available horsepower
      5. available liner sizes
      6. Can the pump speed be varied?
         A. maximum speed allowed
         B. minimum speed allowed
      7. Can the pumps be run in parallel?

i) Maximum surface pressure specified by the Operator
j) Minimum annular velocity
   1. *Rule of Thumb - To clean the hole:*
      A. *the minimum flow rate is 30 gpm/inch of hole diameter.*
      B. *the maximum flow rate is 50 gpm/inch of hole diameter.*
k) Approximate length and inside diameter (ID)
   1. standpipe
   2. swivel
   3. kelly hose
   4. kelly
l) Is it a workover rig or a slimhole rig?
m) Drill collars
   1. size
   2. length
   3. number
n) Drill pipe
   1. size
   2. weight
o) Tool joints
   1. size
   2. weight
p) Is a tapered drill string planned?
q) Desired type of hydraulics program
   1. Maximum bit hydraulic horsepower
      A. The formation is best removed by delivering the most power to the bottom of the hole.
   2. Maximum jet impact force
      A. The formation is best removed when the force of the jets striking the bottom of the hole is the greatest.
r) Will constant pump speeds be maintained or will pump speeds be varied?

2) Hydraulics Formulae

A) Where:

A = total nozzle Area (square inches)
AV = Annular Velocity (feet per minute)
B = hole size factor

Hole Diameter in inches	**B**
$4^3/_4$	2.0
$5^5/_8$ - $6^3/_4$	2.2
$7^3/_8$ - $7^3/_4$	2.3
$7^7/_8$ - 11	2.4
12 - $18^1/_2$	2.5

Cca = drill Collar Annulus loss Coefficient
Ccb = drill Collar Bore loss Coefficient
Ce = surface Equipment loss Coefficient
Cp = drill Pipe loss Coefficient
Dc = outside Diameter of drill Collar (inches)
Dcb = inside Diameter of drill Collar (inches)
Dh = Diameter of Hole (inches)
Dj = outside Diameter of tool Joint (inches)
Djb = inside Diameter of tool Joint (inches)
Dp = outside Diameter of drill Pipe (inches)
Dpb = inside Diameter of drill Pipe (inches)
Em = fractional Mechanical pump Efficiency
Hb = hydraulic Horsepower at Bit
I = Impact force (pounds)
IH = required pump Input Horsepower
Lc = Length of drill Collar string (feet)
Lp = Length of drill Pipe string (feet)
Pb = Pressure drop across bit nozzle (pounds/square inch)
Ps = Surface Pressure (pounds per square inch)
Q = circulation rate (gallons per minute)
V = jet Velocity (feet per second)
MW = Mud Weight (pounds per gallon)

B) Formulae

a) $AV = [\,24.51 \times Q\,] \div [\,Dh^2 - Dp^2\,]$

b) $V = 0.32 \times [\,Q \div A\,]$

c) $Hb = [\,Pb \times Q\,] \div 1{,}714$
$Hb = [\,Q^3 \times MW\,] \div [\,18{,}610{,}573 \times A^2\,]$

d) $I = 0.0173 \times Q \times [\,Pb \times MW\,]^{0.5}$
$I = 0.00016602 \times [\,(Q^2 \times MW) \div A\,]$

e) $Pb = [\,Q^2 \times MW\,] \div [\,10{,}858 \times A^2\,]$

f) $IH = [\,Ps \times Q\,] \div [\,Em \times 1{,}714\,]$

g) $Ccb = 6.1 \div Dcb^{4.86}$

h) $Cca = [\,8.6 \times B\,] \div [\,(Dh - Dc) \times (Dh^2 - Dc^2)^2\,]$

i) $Cp = [\,5.68 \div Dpb^{4.86}\,] +$
$[\,(8.17 \times B) \div ([Dh - Dp] \times [Dh^2 - Dp^2]^2)\,] +$
$[\,0.41 \div Djb^{4.86}\,] +$
$[\,(0.43 \times B) \div ([Dh - Dj] \times [Dh^2 - Dj^2]^2)\,]$

j) Pressure Loss

1. Through and around the drill string and through the surface equipment
$P = 0.00001 \times [\,Ce + ([Ccb + Cca] \times Lc) + (Lp \times Cp)\,] \times [\,MW \times Q^{1.86}\,]$

2. Through and around the drill pipe
$P = 0.00001 \times [\,Lp \times Cp\,] \times [\,MW \times Q^{1.86}\,]$

3. Through the drill collar bore
$P = 0.00001 \times [\,Lc \times Ccb\,] \times [\,MW \times Q^{1.86}\,]$

4. Around the drill collars
$P = 0.00001 \times [\,Lc \times Cca\,] \times [\,MW \times Q^{1.86}\,]$

5. Through the surface equipment
$P = 0.00001 \times [\,Ce \times MW \times Q^{1.86}\,]$

g- Considerations while Drilling

1) Carefully watch and record at regular intervals:

A) Weight indicator

a) Keep neutral point in the drill collars

1. Determine the drill pipe buoyancy factor (**BF**).
BF = [-0.0162 x Mud Weight(ppg)] + 1.011

2. Determine the buoyed weight of the drill string (**BW**).
BW = BF x Total in-air String Weight in pounds

A. For example: if the mud weight is 13 ppg and the drill string weighs 90,000 lbs in air then the buoyed weight is 72,000 lbs.

a. BF = [-0.0162 x 13] + 1.011 = 0.8

b. BW = 0.8 x 90,000 lbs = 72,000 lbs

3. Avoid running the drill pipe in compression by keeping the top 10% - 15% of the drill collars in tension.

A. Determine the buoyed weight of the drill collar assembly.

B. Calculate the maximum bit weight available.

a. A safety factor of 10% would be written as 1.1.

Maximum bit weight available = buoyed drill collar weight in pounds ÷ the safety factor

b) *Rule of Thumb - Weight on bit should be about 4,000 - 5,000 pounds per inch of the bit size (diameter).*

1. This will vary depending on the bit size and the formations being drilled.

B) Pump pressure

C) Mud weight and properties

D) Pit level

E) Rotary speed

F) Changes in drilling time

G) Cuttings

2) Caliper the bit and the stabilizers after each bit trip.

A) Fill the hole after each stand of drill collars to guard against swabbing the well in.

3) It is sometimes advisable to run a magnet and/or a junk basket before running a diamond or a polycrystalline diamond compact (PDC) bit.

4) When was the drill pipe last inspected?

A) Drill pipe should be inspected every 100,000 - 150,000 feet drilled.

a) Conditions in the area determine inspection scheduling.

B) Drill collars should be visually or black light inspected every 200 rotating hours.

C) On a critical well (in deep hostile environment) and while on Daywork, the Operator should have a third party inspect the drill pipe.

a) The Drilling Contractor pays for inspecting the bad joints.

b) This cost is small compared to a fishing job.

5) What size and type of drill pipe is being used?

A) The drill string should be designed for 100,000 pounds of overpull at 80% of the tensile strength of the drill pipe.

6) Periodically check your Driller's pipe tally.

7) Measure and caliper the drill string components that go into the hole.

A) *The importance of this step cannot be emphasized enough!*

8) Maintain water loss between 5 and 2 cubic centimeters per 30 minutes while drilling the zone of interest, depending on mud type and area of drilling.

A) Keep it as low as is practical because water-loss control is expensive.

9) While Drilling

A) What is the fracture gradient in the weak part of the well?

B) Know the kick tolerance factor at all times.

C) Know the slow pump rates for well control.

D) Hold crew well control and training drills.

E) Conduct performance tests on all well control equipment.

F) Establish lines of authority and designate duties to each person.

10) Bit Size Considerations

A) Small bits do not have the lasting power that larger ones have.

a) very slow penetration rates

B) Larger bits can accept more weight and are durably built.

a) faster drilling rates

11) Mud Property Considerations { 46 }

A) As the viscosity of mud, oil content, solids content, and mud density increases, the drilling rate decreases.

B) As the water loss of mud increases, the drilling rate increases.

12) Dogleg Considerations

A) When drilling in a dogleg, the drill pipe is rotated from maximum to minimum stress at each rotation because the drill pipe is making a turn at that particular point.

a) Cyclical stress reversals like this will cause fatigue failures in drill pipe.

- b) If the strength of the drill pipe is exceeded because of drilling through doglegs, expensive fishing jobs or a junked hole could be the result.

B) Some doglegs are so severe that a logging tool cannot get through them trying to get to total depth (TD).

- a) If a logging tool is "spudded" (lightly pounded) through a dogleg, pulling it back through is very difficult without losing the tool in the hole.

C) When casing is run in the hole, it can get stuck in a dogleg.

- a) If this happens, either fish it out or:
  1. cement the string.
  2. drill out the shoe.
  3. set a smaller string to TD.

D) Cementing through a dogleg is difficult.

- a) One side of the casing lays against the wall and prevents the formation of a complete cement sheath.

E) Drilling inside casing set through a dogleg increases the risk of wearing a hole in the casing at the point where the dogleg occurs.

- a) A hole at this point could cause additional drilling problems as well as a blow-out.

F) Doglegs in a producing well will cause problems.

- a) rod wear
- b) tubing leaks
- c) running tools in and out of the hole

13) Keyseat Considerations

A) Keyseat-type sticking can or will eventually occur when:

- a) encountering sloughing shales.
- b) pulling the large OD drill collars into keyseats while tripping out of the hole.
- c) trying to pull a logging tool through keyseats.

h- Preventing and Diagnosing Hole Problems {43}

1) Monitor trends in order to prevent and diagnose hole problems.

A) Keep a record at predetermined intervals.

2) Drilling parameters for the Driller to record

A) Pump pressure changes can indicate:

- a) hole restrictions.
- b) the hole is loading up.
- c) drill string washout(s).
- d) a well control problem.

B) Pump strokes

C) Changes in pressure required to break circulation may indicate:

- a) the hole is loading up.
- b) a well control problem.
- c) the condition of the mud is deteriorating.

D) Changes in torque can indicate:

- a) lithological changes.
- b) the bit is locking up.
- c) a transition zone.

E) Changes in drag may indicate:

- a) a transition zone.
- b) the hole is loading up.
- c) the hole is swelling up.
- d) changes in hole stability.
- e) a possible key seat.

3) Monitor the following to be forewarned about well control possibilities.

A) Changes in flow rate and flow line temperature

B) Bottoms-up time (actual vs. calculated)

C) Rate of penetration

D) Gas

- a) background
- b) connection
- c) gas-cut mud

E) Shale density
F) "d" exponent [C-]
G) Size and shape of the cuttings
H) Changes in the mud properties
I) Pit gains
J) Fill on the connections

4) Monitor the behavior of the hole during trips, both out of and into the hole.
- **A)** Pulling Out of the Hole
  - a) Is a constant volume of mud required to fill the hole?
  - b) Was the pipe slugged (a small, higher viscosity, heavier weight mud pumped into the drill pipe to a predetermined depth)?
    1. What was the weight of the slug?
    2. How long was it pumped?
  - c) Monitor the drag trends, especially if the drag is occurring at about the same depth on each trip
    1. Note any changes between trips.
  - d) Watch for keyseats.
- **B)** Going in the Hole
  - a) Do mud return volumes equal the calculated displacement?
  - b) Note any bridge(s) (obstructions).
    1. their depth(s)
    2. the time it took to ream them out
  - c) Note any hole fill.
  - d) Was there any trip gas?
    1. Is it migrating uphole?
    2. Is it causing problems?
  - e) Is there any lost circulation?
  - f) Mud
    1. weight
    2. condition off of the bottom

5) Monitor the behavior of the hole during connections.
- A) Fill
- B) Bottoms-up from the connection
- C) Bit plugging
- D) Pipe handling
  - a) setting slips
  - b) bending pipe
    1. rotary
    2. mouse hole
  - c) use of tongs

6) Monitor these parameters of the drilling mud.
- A) Derrickman
  - a) weight
  - b) viscosity
- B) Mud Engineer
  - a) plastic viscosity (PV)
  - b) yield viscosity (YV)
  - c) gels and caustics
  - d) test temperature
  - e) chemistry
  - f) Methylene Blue Test (MBT)
  - g) solids
  - h) High Pressure/High Temperature Test (HPHT)
  - i) water loss
  - j) chlorides

7) Monitor the behavior of the pump(s).
- A) Volumetric checks should be made weekly.
- B) Monitor maintenance costs (Drilling Contractor).
- C) Monitor valve/seat repair.
  - a) changes indicate:
    1. corrosion
    2. abrasives
    3. time lost

8) Monitor the overall job or bit rate of penetration as it relates to total job performance.
   - A) Cuttings
   - B) Drag
   - C) Torque
   - D) Lost circulation
   - E) Gas-cut mud
   - F) Incremental cost per foot
     - a) When this value increases dramatically, the bit has reached its economic limit.
   - G) Drilling mud
     - a) solids
     - b) plastic viscosity
     - c) weight
     - d) amount overbalanced
   - H) Bit properties
     - a) type
     - b) weight on bit
     - c) revolutions per minute (rpm)
   - I) Hydraulics

9) Monitor, cross-check, and verify those intervals where lost circulation occurs.
   - A) What operation was in progress when losses began?
   - B) Depth (formation name)
   - C) Mud properties
     - a) weight
     - b) viscosity
     - c) gels
   - D) Rate of penetration (ROP)
   - E) Visual observation of the shale shaker
   - F) Are the solids increasing?
   - G) Hydraulics
   - H) Equivalent circulating density (ECD)
   - I) Amount overbalanced
   - J) Loss Rate
     - a) while circulating
     - b) when pumps are slowed down
     - c) while tripping
   - K) How soon after trip did loss start?
   - L) Note any hole restrictions.
   - M) Check the pressurized mud balance in the pump suction compared to the regular mud balance.
   - N) Water to fill the hole (low weight muds)
   - O) Is blind drilling (drilling without mud returns) an option?

10) Monitor hole deviation throughout the job.
   - A) From vertical
     - a) actual measurements (depth vs. deviation)
     - b) cumulative displacement
   - B) Directional changes
   - C) Dogleg severity
   - D) Drag/keyseat
   - E) Torque
   - F) Pipe sticking tendencies
   - G) Casing wear (possible well control problem)
   - H) Drill pipe wear
   - I) Target (controlled directional plan)
   - J) Weight on bit/rpm program

11) Monitor and record changes in hole stability.
   - A) How many days has the formation been exposed?
   - B) How many trips have been made through the interval?
   - C) Is hole stability associated with:
     - a) lost circulation?
     - b) differential sticking?

c) mechanical sticking?
d) time-sensitive shales?
e) transition zone shales?
f) shale caving?

D) Has the hydraulics program been re-evaluated and determined to be effective?
E) Does shale that has sloughed have a low or high Methylene Blue Test (MBT)?
F) Are there any cuttings changes?

i- Common Drilling Problems - Causes and Solutions {47}

1) Excessive Hole Enlargement	Excess annular velocity	Decrease flow rate
	Low mud weight in pressured shales	Improve mud rheology Increase mud weight Increase mud inhibitiveness
	Water-Sensitive shales	Improve mud rheology Increase mud inhibitiveness
	High wellbore stress	Improve mud rheology Increase mud inhibitiveness Sidetrack (drill around it)
2) Stuck Pipe	Inadequate hole cleaning	Improve mud rheology
	Bad hole configuration	Use lubricant Change drilling assembly Sidetrack
	Poor bottom-hole assembly	Use lubricant Change drilling assembly
	Excessive mud weight	Reduce mud weight Use lubricant
	Low mud weight in pressured shales	Improve mud rheology Increase mud weight Increase mud inhibitiveness
	Differential sticking in sand	Decrease fluid loss Reduce mud weight Use lubricant Modify drilling assembly
	Sticking in shale	Use lubricant Modify drilling assembly Increase mud inhibitiveness
	Water-sensitive shale	Improve mud rheology Increase mud inhibitiveness
	High wellbore stresses	Improve mud rheology Increase mud inhibitiveness Sidetrack
	Bit balling	Increase mud inhibitiveness Use lubricant

3) Lost Circulation	Inadequate hole cleaning	Improve mud rheology
	Excessive mud weight	Reduce mud weight
	Water-sensitive shale	Improve mud rheology Increase mud inhibitiveness
	High wellbore stresses	Improve mud rheology Increase mud inhibitiveness Sidetrack
	Bit balling	Increase mud inhibitiveness Use lubricant
	Mud properties causing excessive annular pressure drops while circulating	Lower/adjust the equivalent circulating density (ECD)
	Swab/surge pressures breaking down the hole	Slow down on trips
4) Excessive Torque and Drag	Inadequate hole cleaning	Improve mud rheology
	Bad hole configuration	Use lubricant Change drilling assembly Sidetrack
	Poor bottom-hole assembly	Use lubricant Change drilling assembly
	Excessive mud weight	Reduce mud weight
	Low mud weight in pressured shales	Improve mud rheology Increase mud weight Increase mud inhibitiveness
	Differential sticking in sand	Decrease fluid loss Reduce mud weight Use lubricant Modify drilling assembly
	Sticking in shale	Use lubricant Change drilling assembly Increase mud inhibitiveness
	Water-sensitive shale	Improve mud rheology Increase mud inhibitiveness Decrease fluid loss
	High wellbore stresses	Improve mud rheology Increase mud inhibitiveness Sidetrack

5) Slow Drilling	Inadequate hole cleaning	Improve mud rheology
	Bad Hole configuration	Use lubricant Change drilling assembly Change to oil-based mud Sidetrack
	Poor bottom-hole assembly	Use lubricant Change drilling assembly
	Excessive mud weight	Reduce mud weight
	Bit balling	Increase mud inhibitiveness Use lubricant Change bit types
6) Swabbing on Connections and Trips	Inadequate hole cleaning	Improve mud rheology
	Bottom-hole assembly	Use lubricant Change drilling assembly
	Low mud weight in pressured shales	Improve mud rheology Increase mud weight Increase mud inhibitiveness
	Bit balling	Increase mud inhibitiveness Use lubricant
7) Directional Problems	Excess annular velocity	Decrease flow rate
	Bad hole configuration	Use lubricant Change drilling assembly Sidetrack
	Poor bottom-hole assembly	Use lubricant Change drilling assembly
	Differential sticking in sand	Decrease fluid loss Reduce mud weight Use lubricant Change drilling assembly
	Sticking in shale	Use lubricant Change drilling assembly Increase mud inhibitiveness
	High wellbore stresses	Improve mud rheology Increase mud inhibitiveness Sidetrack
	Bit balling	Increase mud inhibitiveness Use lubricant

B- INDIVIDUAL CREW MEMBER DUTIES

a- During Routine Operations {33}

1) Floorhand
   - A) Report any abnormalities to the Driller.
   - B) Watch for changes in the:
     - a) pit level.
     - b) mud weight.
     - c) mud properties.
     - d) flow rate from the well.
   - C) Check valves and lines in the mud system.
   - D) Make sure the de-gasser and separator are working properly.
   - E) Repair all equipment malfunctions as soon as possible.

2) Motorman
   - A) Keep all motors in working order
   - B) Change the oil and lubricants regularly.

3) Derrickman
   - A) Make daily inventories of all of the sacked materials on hand.
   - B) Alert the Driller about changes in:
     - a) pump performance.
     - b) characteristics of the cuttings.
     - c) mud properties.
   - C) Continue to check the mud-monitoring equipment.
     - a) flow
     - b) shows
     - c) pit watchers
     - d) gas detectors
   - D) Monitor mud weight and mud properties.
   - E) Report any malfunctions in the equipment to the Driller.

4) Driller
   - A) Maintain constant supervision over the crew and their activities.
     - a) Driller actually drills the well.
   - B) Make sure that all well control equipment is working properly.
   - C) Look for changes in the:
     - a) drilling rates.
     - b) flow checks during drilling breaks.
     - c) mud properties.
     - d) pit level fluctuations.
     - e) flow rate changes.

5) Toolpusher
   - A) Make sure that all personnel perform their duties.
   - B) Make sure that the rig conforms to safety standards.
   - C) Stock and maintain spare parts in good working order to repair and maintain the rig.

6) Mud Engineer
   - A) Make sure that there are enough barite and chemicals on location to kill the well if a kick is taken.
   - B) Be alert to mud property changes and hole changes.
   - C) Make daily checks of mud properties.
     - a) Submit an accurate daily report.

7) Mud Logger
   - A) Rig up and maintain the logging unit.
   - B) Repair all malfunctions immediately.
   - C) Monitor the hole during drilling and trips.
   - D) Observe cuttings and report changes.
   - E) Report drilling breaks.

8) Company Man
   A) Ultimately responsible for Footage and Daywork operations.
   B) Make sure that all personnel perform their duties.
   C) Minimize pumping costs.
   D) Maximize penetration rates.
   E) Make sure that the mud lifts the cuttings efficiently.
   F) Lower the swab and surge pressures.
   G) Lower the pressure required to break circulation.
   H) Separate drill solids and entrained gas at the surface.
   I) Minimize hole erosion.

b- During Well Control Operations

1) Crew members duties:
   A) will vary with rig, Drilling Contractor, and Operator.
   B) should be posted in the dog house (a sheltered place for the hands to sit after they have caught up on all of their work).

2) Floorhand
   A) Assist the Derrickman in mud mixing.
   B) Report and repair equipment malfunctions.

3) Derrickman
   A) Monitor and maintain the mud pumps and mud system.
   B) Report any malfunctions.

4) Driller
   A) Direct crew members.
   B) Check the operating condition of:
      a) chokes.
      b) accumulators.
      c) controls.
      d) blow-out preventers (BOPs).
   C) Activate the alarm and notify the Toolpusher.
   D) Hoist the kelly above the rotary table.
   E) Shut off the pumps and check for flow.
      a) If flowing:
         1. open choke valve.
         2. close top annular.
         3. close lower kelly cock.
         4. close choke.
   F) Maintain operation of the pump at the directed speed.
   G) If not in violation of company procedures:
      a) break off the kelly above the lower cock and install the circulating head.
      b) land drill pipe on top pipe rams.
      c) connect chicksans (reinforcement rods) to the standpipe manifold.
      d) open the kelly cock to observe the pressures.

5) Mud Engineer
   A) Check the mud.
   B) See that the mud meets the requirements.
   C) Supervise the mixing of the mud.

6) Toolpusher
   A) Check the rig and the personnel for safety.
   B) Report the well status to the Operator's representative.

7) Company Man
   A) Direct well control operations.
   B) Prepare the kill sheet.
   C) Record pressure changes.

C- OIL FIELD FORMULAE { 48, 49, 50 }

a- General Measurements

1) 38 steps for average height person on flat open ground = @ 100 feet
2) 48 steps for average height person on brushy ground = @ 100 feet
3) 1,000 cubic centimeters = 0.26 gallons = @ 1 quart
4) 1 acre = 43,560 $feet^2$
5) Pipe inside diameter (ID) $inches^2$ = @ number of barrels per 1,000 feet of depth
6) 1 barrel displacement = @ 4.75 sacks of cement
7) 1 sack of cement = @ 0.21 barrel displacement
8) Slurry volume in $feet^3$ = cement yield x number of sacks
9) 1 cubic foot of air = 0.076 pounds
10) 1 barrel = 350 pounds of fresh water = 2,745 pounds of steel
11) 1 $foot^3$ = 62.4 pounds of fresh water = 489 pounds of steel
12) 1 foot = 30.48 centimeters
13) 1 inch = 2.54 centimeters
14) 1 meter = 3.281 feet = 39.37 inches
15) Velocity in feet per minute = $[1{,}029.42 \times BPM] \div ID^2$
    A) barrels per minute (bpm)
    B) inside diameter (ID)
16) True thickness determination in deviated holes

    Cosine theta = T ÷ t

    A) Where:
    theta = angle of deviation
    T = true thickness
    t = apparent thickness

b- Area

1) Area of a circle = $\pi \times r^2 = [\pi \times D^2] \div 4 = D^2 \times 0.7854$
2) Cross-sectional area of pipe = $[OD^2 - ID^2] \times 0.7854$
3) Area of a square or rectangle = length x width
4) Area of a triangle =
    A) $[\frac{1}{2}$ base $] \times$ perpendicular height (right triangle)
    B) $[\frac{1}{2} (b \times c)] \times$ SineA
    C) $[\frac{1}{2} (c \times a)] \times$ SineB
    D) $[\frac{1}{2} (a \times b)] \times$ SineC
    E) $[a^2 \times$ SineB $\times$ SineC $] \div [2 \times$ SineA $]$
    F) $[s \times (s - a) \times (s - b) \times (s - c)]^{0.5}$
        a) $s = \frac{1}{2} [a + b + c]$
    G) Where:
    Small letters (a, b, c) represent the sides of the triangle.
    Capital letters (A, B, C) are the angles opposite those sides.
    e.g. - The angle opposite of side a is angle A.

c- Volume

1) General
    A) 1 acre-foot = 7,757 barrels = 43,560 $feet^3$
    B) 1 barrel = 42 gallons = 5.6154 $feet^3$ = 158.98 liters
    C) 1 $foot^3$ = 7.481 gallons = 28.32 liters
    D) 1 gallon = 231 $inches^3$ = 0.1337 $foot^3$ = 3.785 liters
    E) 1 liter = 0.03532 $feet^3$ = 0.2642 gallon

2) Volume of a Mud Pit in Barrels =

[length(ft) x width(ft) x depth(ft)] ÷ 5.614

A) 1 cubic foot per inch of depth = 0.0833 x length(ft) x width(ft)

B) 1 cubic foot per inch of depth = 0.00058 x length(in) x width(in)

C) (#) barrels per inch of depth = 0.0148 x length(ft) x width(ft)

3) Volume Increase from Addition of Barite

Vi = N ÷ 14.9 sacks per barrel

A) Where:

Vi = volume increase in barrels
N = number of sacks of barite added to the system

4) Volume Increase from Addition of Bentonite

Vi = N ÷ 8.75 sacks per barrel

A) Where:

Vi = volume increase in barrels
N = number of sacks of bentonite added to the system

5) Volume Increase in Weighting

Vi = [100 x (MW2 - MW1)] ÷ [N - MW2]

A) Where:

V = volume increase in barrels per 100 barrels of mud
MW1 = initial mud weight in pounds per gallon
MW2 = final mud weight in pounds per gallon
N = weight of weighting material in pounds per gallon
(barite: N = 35, bentonite: N = 20.8)

6) Volume of Water Needed to Lower the Mud Weight

N = [V x (MW1 - MW2)] ÷ [MW2 - 8.33]

A) Where:

N = number of barrels of water required
V = volume of mud system in barrels
MW1 = original mud weight in pounds per gallon
MW2 = desired mud weight in pounds per gallon
8.33 = weight of fresh water in pounds per gallon

7) Amount of Mud in the System

V = Vp + Vh

A) Where:

V = volume of mud in the system
Vp = volume of mud in the pit in barrels
Vh = volume of mud in the hole in barrels

8) Volume of Mud Needed to Fill the Hole

V = length of pipe x metal displacement factor

V = Vh - Ddp

A) Where:

Vh = volume of mud in the hole in barrels per feet
(open hole capacity)
Ddp = drill pipe displacement

9) Volume of Mud in the Hole

Vh = [(D ÷ 2)^2 x 37.7 x depth(ft)] ÷ 9,697

A) Where:

Vh = volume of mud in the hole
D = average diameter of the hole in inches

B) Calculate, then total for each interval if multiple strings were set.

10) Volume of Mud in the Pit

Vp = [l x w x h] ÷ 5.6

A) Where:

Vp	= volume of mud in the pit
l	= length of the pit in feet
w	= width of the pit in feet
h	= height or depth of mud in the pit in feet
5.6	= number of cubic feet per barrel

11) Annular Capacity of the Hole

Ca = [Dh^2 - OD^2] ÷ 1,029

A) Where:

Ca	= annulus capacity in barrels per foot
Dh	= diameter of the hole in inches
OD	= outside diameter of the pipe in inches

12) Mud Cycling Time

t = V ÷ [p x S]

A) Where:

t	= cycling time in minutes
V	= volume of mud in the system in barrels
p	= volume of mud per pump stroke in barrels
S	= pumping rate in strokes per minute

13) Annular Velocity of Mud

AV = PO ÷ Ca

A) Where:

AV	= annular velocity in feet per minute
PO	= pump output in barrels per minute
Ca	= annular capacity of mud in barrels per foot

14) Volume of a Cylindrical Tank

A) in barrels = [diameter(ft)^2 x height(ft)] x 0.1399

B) number of barrels = [0.7854 x diameter(ft)^2 x height(ft)] ÷ 5.6146

C) number of cubic feet = [pi x diameter(ft)^2 x height(ft)] ÷ 4

D) in barrels per foot = diameter(ft)^2 ÷ 7.14

E) in barrels per inch = diameter(ft)^2 ÷ 85.7

15) Volume of a Rectangular Tank

A) volume in barrels = [length(ft) x width(ft) x height(ft)] ÷ 5.6146

B) number of barrels per inch = 0.0143 x length(ft) x width(ft)

C) number of cubic feet per inch = 0.0833 x length(ft) x width(ft)

16) Volume Capacity of Pipes

A) cubic feet per 1,000 feet = 5.454 x ID inches^2

B) barrels per mile = 5.1291 x ID inches^2

C) barrels per 1,000 feet = 0.9714 x ID inches^2

D) barrels per foot = ID inches^2 ÷ 1,029

E) gallons per mile = 215.424 x ID inches^2

F) gallons per 1,000 feet = 40.8 x ID inches^2

G) If conditions change, use either Charles' Law, Boyle's Law or the Ideal Gas Law to account for the changes in pressure, temperature, and volume. [**C- v- 1), 2), 3)**]

17) Volume of a Hose

A) 2 inch hose = 0.02 cubic feet per foot of length

B) 2.5 inch hose = 0.03 cubic feet per foot of length

C) 3 inch hose = 0.04 cubic feet per foot of length

D) 4 inch hose = 0.08 cubic feet per foot of length

18) Hole Volumes

A) Pipe out of the hole (Volume A in barrels)

a) Calculate for each interval and total.

Volume A = [(hole diameter ÷ 2)² x 37.7 x depth(ft)] ÷ 9,697

B) Pipe in the hole (Volume B in barrels)

Volume B = Volume A - displacement of drill pipe and collars

C) Empty hole volume in barrels

V = [hole diameter² ÷ 1,029] x length(ft)

d- Mud Weight

1) General

A) 1 grain = 0.0001429 pounds = 0.0648 grams

B) 1 pound = 0.4536 kilogram

C) 1 metric ton = 2,205 pounds

D) 1 gram/cm³ = 62.43 pounds/ft³ = 8.345 pounds/gal

E) Mud gradient(psi/ft) = MW(ppg) ÷ 19.24 = MW(ppg) x 0.052

F) Pounds per cubic foot(pcf) = MW(ppg) ÷ 0.1337 = MW(ppg) x 7.48

G) Pounds per gallon(ppg) = MW(pcf) ÷ 7.48 = MW(pcf) x 0.1337

2) Weighting Mud with Barite

B = [1,470 x (MW2 - MW1)] ÷ [35 - MW2]

A) Where:

B = number of sacks of barite per 100 barrels of mud
MW1 = initial mud weight in pounds per gallon
MW2 = desired mud weight in pounds per gallon

B) Number of Sacks of Barite Added to the System

Sx = [system volume(bbls) x 14.7 x (new MW - old MW)] ÷ [35.4 - new MW]

3) Weighting Mud with Bentonite

B = [874 x (MW2 - MW1)] ÷ [20.8 - MW2]

A) Where:

B = number of sacks of bentonite per 100 barrels of mud
MW1 = initial mud weight in pounds per gallon
MW2 = desired mud weight in pounds per gallon

4) Decrease Mud Weight by Adding Fresh Water

X = [100 x (MW1 - MW2)] ÷ [MW2 - 8.33]

A) Where:

X = number of water barrels added per 100 barrels of mud
MW1 = initial mud weight in pounds per gallon
MW2 = desired mud weight in pounds per gallon
8.33 = weight of fresh water in pounds per gallon

5) Resulting Mud Weight from Addition of Fresh Water

MW2 = [(V x MW1) + (8.33 x N)] ÷ [N + V]

A) Where:

MW2 = resulting mud weight in pounds per gallon
V = volume of the system
MW1 = initial mud weight in pounds per gallon
8.33 = weight of fresh water in pounds per gallon
N = number of barrels of water added

6) Mud Weight

MW = Sppg + Mppg

A) Where:

MW = mud weight in pounds per gallon

Sppg = [% drilled Solids x SpGr Solids x water weight(ppg)] + [% other additives (i.e..oil) x SpGr other additives x water weight(ppg)]

Mppg = [1 - (% drilled Solids + % other additives)] x weight of medium(ppg)

B) The medium can be either:

a) fresh water: @ 8.33 pounds per gallon.

b) salt water: @ 8.9 pounds per gallon.

C) Assume that the chloride concentration is insignificant.

7) Percent of Low Specific Gravity Solids

X = [(Z x 100) - 460] ÷ 1.6

A) Where:

X = percent of low specific gravity solids

Z = the average of the solids gravity, assuming that all solids are either barite (SpGr = 4.2) or low gravity solids (SpGr = 2.6)

% Solids = % Low Gravity Solids (LGS) + % other solids

B) The weight of LGS is equal to the weight of an equal volume of fresh water multiplied by 2.6. (e.g.)

a) One barrel of fresh water weighs 350 pounds.

b) Calculate 1% of LGS.

0.01 x 350 x 2.6 = 9.1 pounds

C) If the % LGS is known, then the weight of the LGS can be calculated in pounds per barrel. (e.g.)

a) Percent solids that are LGS is 7.8%.

b) Calculate the concentration in pounds per barrel.

0.078 x 9.1 = 0.7 pounds per barrel LGS

8) Slugging

A) Slug Volume in barrels

Vs = [MW x dry pipe length x pipe capacity] ÷ [slug weight - MW]

B) Slug Weight in pounds per gallon

Ws = [(MW x dry pipe length x pipe capacity) ÷ slug volume] + MW

9) Equivalent Circulating Density

ECD = MW + [P ÷ (0.052 x TVD)]

A) Where:

P = annular pressure loss > poi
(> poi refers to above point of interest)

TVD = true vertical depth of the point of interest

10) Fracturing Mud Weight

FMW = MW + [Ps ÷ (0.052 x TVDs)]

A) Where:

FMW = fracture point of a formation expressed as equivalent mud weight(ppg)

MW = mud weight(ppg) in the hole at the time of the formation breakdown

Ps = surface pressure(psi) imposed on the column

TVDs = true vertical depth of the casing shoe

11) Equivalent Mud Weight

EMW = expected pressure ÷ [0.052 x depth]

EMW = [Ps x (19.25 ÷ TVDs)] + MW

A) Where:

EMW = equivalent mud weight in pounds per gallon
Ps = surface pressure(psi) applied during Leak-off Test
TVDs = true vertical depth of the casing shoe

12) Kill Mud Weight Required to Control Kick

KMW = [sidpp ÷ (0.052 x depth)] + MW

KMW = [(sidpp ÷ TVD) ÷ 0.052] + MW

KMW = [(sidpp x 19.25) ÷ TVD] + MW

A) Where:

KMW = kill weight of the mud in pounds per gallon
sidpp = shut-in drill pipe pressure(psi)
TVD = true vertical depth of the point of interest

B) Reminder:

a) Hydrostatic Pressure(psi) = 0.052 x MW x TVD
b) Gradient(psi/ft) = 0.052 x MW
c) Mud Weight(ppg) = Gradient ÷ 0.052

13) Kill Mud Weight or New Mud Weight

MW2 = MW1 + MWisidpp + MWiop

A) Where:

MW2 = kill mud weight or new mud weight in pounds per gallon
MW1 = original mud weight in pounds per gallon
MWisidpp = mud weight increase(ppg) to compensate for shut-in drill pipe pressure
MWiop = mud weight increase(ppg) required for overbalance pressure

14) Mud Weight Increase

MWisidpp = sidpp ÷ [TVD x C]

MWiop = op ÷ [TVD ÷ C]

A) Where:

MWisidpp = mud weight increase(ppg) to compensate for shut-in drill pipe pressure
MWiop = mud weight increase required for overbalance pressure
sidpp = shut-in drill pipe pressure(psi)
TVD = true vertical depth at the point of interest
op = overbalance pressure(psi)
C = constant of 0.052

e- Pipe Volumes

1) Weight per Foot of Pipe or Tubing

A) Where:

W = weight in pounds per foot
OD = pipe outside diameter
t = wall thickness

B) Plain end round pipe and tubing

W = [10.68 x (OD - t)] x t

C) Square pipe or tubing

W = [13.60 x (OD - t)] x t

D) Rectangular pipe or tubing

W = [6.8 x ([OD long side + short side] - [2 x t])] x t

2) Pipe Capacity

$Cp = ID^2 \div 1{,}029$

A) Where:

- Cp = pipe capacity in barrels per foot
- ID = pipe inside diameter

3) Displacement

A) Where:

- Db = displacement in barrels
- Dbf = displacement in barrels per foot
- Dcf = displacement in cubic feet
- W = weight of pipe in pounds per foot
- OD = pipe outside diameter
- ID = pipe inside diameter

B) Of pipe in barrels

Db = [0.000367 x W with couplings] x depth(ft)

C) Of pipe in cubic feet

Dcf = [0.002 x W with couplings] x depth(ft)

D) Of pipe in barrels per foot

$Dbf = [\ OD^2 - ID^2\ ] \div 1{,}029$

E) Of drill pipe in barrels per foot (X & S Grades)

$Dbf = W \div 2{,}500$

F) Of drill pipe in barrels per foot (E & G Grades)

$Dbf = W \div 2{,}600$

G) Of drill collars, tubing, casing, etc. in barrels per foot

$Dbf = W \div 2{,}750$

4) Annulus Capacity

$Ca = [\ Dh^2 - OD^2\ ] \div 1{,}029$

A) Where:

- Ca = annulus capacity in barrels per foot
- Dh = diameter of the hole in inches
- OD = outside diameter of the pipe in inches

f- Circulating Data

1) General

A) Where:

- Q = flow rate in barrels per minute

B) Q = barrels per stroke x strokes per minute

C) Bottoms-up time = annular volume in barrels ÷ Q

D) Surface to bit time = drill string volume in barrels ÷ Q

E) Total circulating time = total circulating volume ÷ Q

F) Annular velocity(ft/min) = Q ÷ annulus capacity in barrels per foot

2) Circulating Rate of Pumps

A) Single-acting pump

$V = 0.0000081053 \times Dp^2 \times l \times p \times S$

a) Where:

- V = pump rate in barrels per stroke
- Dp = diameter of plunger in inches
- l = stroke length in inches
- p = number of plungers in the pump
- S = strokes per minute

B) Duplex double-acting pump

$V = 0.000162 \times l \times S \times e \times [(2 \times Dl^2) - Dr^2]$

a) Where
- V = pump rate in barrels per stroke
- l = stroke length in inches
- S = strokes per minute
- e = % pump efficiency
- Dl = diameter of the liner in inches
- Dr = diameter of the rod(s) in inches

b) Capacity of Duplex Mud Pumps at 100% Efficiency

Liner Dia. (inches)	**Stroke Length** (inches) 12	14	16	18
$4^1/_2$	.074	.082	---	---
5	.089	.104	.113	.128
$5^1/_2$	.110	.128	.141	.158
6	---	.154	.170	.192
$6^1/_2$	---	.183	.203	.228
7	---	.213	.238	.267
$7^1/_2$	---	.241	.275	.310

(in bbls/stroke)

C) Triplex output pump

$V = [\text{Liner ID}^2 \times 0.000972 \times (l \div 12)] \times 3$

$V = [\text{Liner ID}^2 \times l] \div 4{,}118$

a) Where:
- V = pump rate in barrels per stroke
- l = stroke length in inches

b) Capacity of Triplex Mud Pumps at 100% Efficiency

Liner Dia. (inches)	**Stroke Length** (inches) 9	10	11	12
5	.055	.061	.067	.073
$5^1/_2$	.066	.074	.081	.088
6	.079	.087	.096	.105
$6^1/_2$	.092	.103	.113	.123
7	.107	.119	.131	.143
$7^1/_2$	.123	.137	.150	.164

(in bbls/stroke)

3) Pressure and Pump Rate

$P2 = P1 \times [S2 \div S1]^2$

A) Where:
- P2 = new pump pressure in pounds per square inch
- P1 = old pump pressure in pounds per square inch
- S2 = new pump speed in strokes per minute (spm)
- S1 = old pump speed in strokes per minute

4) Pump Horsepower

$hp = [R \times P] \div 48{,}000$

A) Where:
- hp = horsepower required to drive the pump
- R = rate of flow in barrels per day
- P = delivery pressure in psi from the gauge (psig)

5) Pipe Washout

PW = [Spi x Ot] ÷ Cp

A) Where:

PW	= pipe washout depth in feet
Spi	= number of strokes on the stroke-counter when the pressure increased
Ot	= true pump output
Cp	= pipe capacity in barrels per foot

B) To find the depth of the pipe washout:

a) zero the stroke-counter.

b) drop a piece of soft line or rope into the hole.

c) when the pump pressure increases, read the number of pump strokes.

6) Lag Time (bit to surface)

A) Annulus capacity (bbls/ft) = [Dh^2 - OD drill $pipe^2$] ÷ 1,029

B) Total barrels in the annulus = annulus capacity x depth(ft)

C) Total lag (number of strokes) = total bbls ÷ pump output(bbls/stroke)

D) Lag time in minutes = total strokes ÷ strokes per minute

g- Pressure

1) General

A) 1 atmosphere = 14.7 psi = 1.0332 kg/cm^2

B) 1 pound per square inch = 0.07031 kg/cm^2 = 0.06805 atm

C) 1 kilogram per $centimeter^2$ = 0.96735 atm = 14.22 psi

D) Pressure gradient (psi/ft) = MW(ppg) x 0.052

E) Hydrostatic pressure (psi) = MW(ppg) x 0.052 x TVD

F) Force (pounds) = Pressure x Area

2) Well Control

A) Leak-off Calculations

a) Equivalent mud weight at the shoe

EMWs = [Ps x (19.25 ÷ TVDs)] + MW

1. Where:

EMWs	= equivalent mud weight at the shoe(ppg)
Ps	= applied surface pressure
TVDs	= true vertical depth of the shoe

b) Maximum casing pressure

Pcmax = [EMWs test - MW] x 0.052 x TVDs

1. Where:

Pcmax	= maximum casing pressure that a well can withstand without fracturing at the shoe(psi)
EMWs	= equivalent mud weight at the shoe(ppg) during the leak-off test
TVDs	= true vertical depth of the shoe

c) Maximum kick

Kmax = [(EMWs test - MW) x TVDs] ÷ TVDw

1. Where:

Kmax	= maximum kick that can be shut-in without fracturing the formation at the shoe(ppg)
EMWs	= equivalent mud weight at the shoe(ppg) during the leak-off test
TVDs	= true vertical depth of the shoe
TVDw	= true vertical depth of the well

d) Density of the kick fluid

1. Where:

   Dkf = density of the kick fluid(ppg)
   sicp = shut-in casing pressure
   sidpp = shut-in drill pipe pressure
   Ca = annulus capacity around the drill collars(bbls/ft)
   pg = pit gain in barrels
   Kh = kick height in feet

Dkf = MW - [([sicp - sidpp] x [Ca x 19.25]) ÷ pg]

OR

Dkf = MW - [([sicp - sidpp] x 19.25) ÷ Kh]

Kh = pg ÷ Ca

2. If the kick density is @: The medium is probably:

If the kick density is @:	The medium is probably:
8.9 ppg	salt water
7.5 ppg	oil
7.0 ppg	crude oil
2.0 ppg	dry gas

e) Capacity

1. Capacity (bbls/ft) = ID^2 ÷ 1,029
2. Barrel capacity per 1,000 feet of pipe = ID^2
3. Annulus capacity (bbls/ft) = [D $hole^2$ - OD $pipe^2$] ÷ 1,029

f) Displacement

1. Displacement in barrels = pipe weight ÷ 2,600
2. Displacement in barrels per foot = pipe weight per foot ÷ 2,600

g) Pump output

1. True pump output in barrels per stroke =
   pump output at 100% x % efficiency
2. Number of strokes to pump a given volume =
   volume to be pumped in barrels ÷ true pump output
3. For additional pump-output information, see pages 202, 203.

B) Kill Mud Weight Required to Control Kick

KMW = [sidpp ÷ (0.052 x depth)] + MW

KMW = [(sidpp ÷ TVD) ÷ 0.052] + MW

KMW = [(sidpp x 19.25) ÷ TVD] + MW

a) Where:

   KMW = kill weight of the mud in pounds per gallon
   sidpp = shut-in drill pipe pressure
   TVD = true vertical depth of the point of interest

b) Reminder:

1. Hydrostatic Pressure(psi) = 0.052 x MW x TVD
2. Gradient(psi/ft) = 0.052 x MW
3. Mud Weight(ppg) = Gradient ÷ 0.052

C) Initial Circulating Pressure

Pic = Pkr + sidpp

a) Where:

   Pic = initial circulating pressure
   Pkr = kill-rate pressure (slow pump pressure measured at previous intervals during drilling)
   sidpp = shut-in drill pipe pressure

D) Final Circulating Pressure

$$Pfc = Pkr \times [\ MW2 \div MW1\ ]$$

a) Where:

- Pfc = final circulating pressure
- Pkr = kill-rate pressure (slow pump pressure measured at previous intervals during drilling)
- MW2 = new mud weight
- MW1 = old mud weight

E) Maximum Casing Pressure while Circulating a Kick

$$Pcmax = 0.2 \times [\ (Pf \times pg \times KMW) \div Ca\ ]^{0.5}$$

a) Where:

- Pcmax = maximum casing pressure that should be expected while a kick is being circulated through a surface choke
- Pf = formation pressure
- pg = pit gain in barrels
- KMW = kill weight of the mud
- Ca = annulus capacity in barrels per foot

F) Maximum Casing Pressure at the Surface

$$PcmaxS = 0.052 \times [dc \times (FMW - MW)]$$

a) Where:

- PcmaxS = maximum casing pressure at the surface
- dc = depth of the casing
- FMW = fracturing mud weight in pounds per gallon
- MW = mud weight in the hole in pounds per gallon

G) Maximum Allowable Surface Pressure, or critical surface pressure

$$PsmaxA = [\ FG - MG\ ] \times dcs$$

a) Where:

- PsmaxA = maximum allowable surface pressure
- FG = fracture gradient in psi per foot
- MG = mud gradient in psi per foot
- dcs = depth of the casing seat in feet

H) Maximum Casing Pressure

$$Pcmax = [\ EMWs\ test - MW\ ] \times 0.052 \times TVDs$$

a) Where:

- Pcmax = maximum casing pressure before losing circulation at the shoe(psi)
- EMWs = equivalent mud weight at the shoe(ppg)
- TVDs = true vertical depth of the shoe

I) Bottom-Hole Pressure

$$BHP = HP + sidpp$$

a) Where:

- BHP = bottom-hole pressure
- HP = hydrostatic pressure
- sidpp = shut-in drill pipe pressure

J) Influx Height

$$IH = pg \div Ca$$

a) Where:

- IH = influx height
- pg = pit gain in barrels
- Ca = annulus capacity around the drill collars(bbls/ft)

K) Kick Tolerance Factor

$$KTF = [\ FG - MW\ ] \times [\ dc \div TVD\ ]$$

a) Where:

- KTF = kick tolerance factor in pounds per gallon
- FG = fracture gradient in pounds per gallon
- dc = depth of the casing
- TVD = true vertical depth

L) Maximum Kick

Kmax = [(EMWs test - MW) x TVDs] ÷ TVDw

a) Where:

Kmax	= maximum kick in pounds per gallon
EMWs	= equivalent mud weight at the shoe(ppg)
TVDs	= true vertical depth of the shoe
TVDw	= true vertical depth of the well

M) Kick Height

Kh = pg ÷ Ca

a) Where:

Kh	= kick height in feet
pg	= pit gain in barrels
Ca	= annulus capacity around the drill collars(bbls/ft)

b) Hole washouts will create inaccuracies in true pit gain measurements.

c) An accurate pit gain measurement is required or it will throw off the calculations.

h- Buoyancy

1) Buoyed Weight of the Drill String

BW = AW x BF

A) Where:

BW	= buoyed weight of the drill string
AW	= air weight of the drill string
BF	= buoyancy factor

2) Buoyancy Factor

BF = [65.44 - MW] ÷ 65.44

BF = 1 - [0.015 x MW]

A) Where:

BF	= buoyancy factor
MW	= mud weight in pounds per gallon

i- Trigonometry

1) General

A) Cosine of dip angle = true thickness of zone ÷ apparent thickness

B) Conversions

a) 60 seconds = 1 minute

b) 60 minutes = 1 degree

2) For example: in a right triangle

A) A + B = 90°

B) C = 90°

C) Tangent theta = Opposite ÷ Adjacent = Sine theta ÷ Cosine theta

D) Sine theta = Opposite ÷ Hypotenuse

E) Cosine theta = Adjacent ÷ Hypotenuse

F) H = a Cosecant theta

G) O = b Tangent theta

H) A = a Cotangent theta

I) H = b Secant theta

J) $c^2 = a^2 + b^2$

K) Where:

theta	= angle other than the right angle
O	= length of the side of the triangle that is opposite of the angle theta
A	= length of the side of the triangle that is adjacent to theta
H	= length of the hypotenuse of the triangle

3) Sine Rule

A) In any triangle: [a + SineA] = [b + SineB] = [c + SineC]

B) Where:

a = the length of the side that connects angle B to angle C
b = the length of the side that connects angle C to angle A
c = the length of the side that connects angle A to angle B

4) To Determine the Length of Any Side of a Triangle

$a^2 = b^2 + c^2$ - [(2 x [b x c]) x Cosine A]

j- Drilling Rate

DR = [I x 60] + ET

1) Where:

DR = drilling rate in feet per hour
I = interval in feet
ET = number of minutes it took to drill the interval

k- Energy Equivalents (MBtu)

1) Hydroelectric, geothermal, and nuclear (KW)	0.00034
2) Kilowatt per hour	0.0003412
3) Kerosene per gallon	0.134
4) Natural gas per cubic foot	1.032
5) Shale oil per barrel	5.4
6) Crude oil per barrel and derivatives	5.8
7) Bituminous coal per ton	12.0
8) Anthracite coal per ton	12.7
9) Coal per short ton (2,000 lbs)	22.4

l- Crude Oil Conversions

1) For Specific Gravity 0.8594 and API 33.15

To Convert the items listed below.. ...Into items listed at the column heads below, multiply by the amount found at the intersection of the row and column.

	Metric Tons	Barrels	Kilo-Liters	1,000 Gallons (IMP)	1,000 Gallons (US)
Metric Tons	1.000	7.31	1.160	0.256	0.308
Barrels	0.136	1.00	0.159	0.035	0.042
Kiloliters	0.863	6.29	1.000	0.220	0.264
1,000 gal (IMP)	3.910	28.60	4.550	1.000	1.201
1,000 gal (US)	3.250	23.80	3.790	0.833	1.000

2) For example: convert 50 barrels to kiloliters.

50 x 0.159 = 7.95 kiloliters

p- Formulae for Multiple String Installations

1) Determine the smallest Casing ID in which multiple strings of tubing can be run, where all strings are made up of the same *type* of tubing.

   A) Two strings of tubing:

   Minimum running casing ID = 2 x OD of tubing joint

   B) Three strings of tubing:

   Minimum running casing ID = 2.1547 x OD of tubing joint

   C) Four strings of tubing:

   Minimum running casing ID = 2.414 x OD of tubing joint

2) Determine the annulus capacity of multiple tubing installations where all tubing is the same *size*.

   $$\mathbf{Ca = [\ 3.14 \times (D1 \div 24)^2\ ] - [\ N \times (3.14 \times [D2 \div 24]^2)\ ]}$$

   A) Where:

Ca	= annulus capacity in foot^3 per linear foot
D1	= inside diameter of casing or open hole(inches)
D2	= outside diameter of tubing(inches)
N	= number of strings of tubing (all same size)

   B) To convert to barrel per linear foot, see page 209.

q- Conversion Table for Various Gravity Oils

API Gravity	Specific Gravity	API Gravity	Specific Gravity
12	0.9861	37	0.8398
15	0.9659	38	0.8348
18	0.9465	39	0.8299
20	0.9340	40	0.8251
22	0.9218	41	0.8203
24	0.9100	42	0.8156 diesel fuel
26	0.8984	43	0.8109
28	0.8871	44	0.8063
30	0.8762	46	0.7972
31	0.8708	48	0.7883
32	0.8654	50	0.7796
33	0.8602	55	0.7587
34	0.8550	60	0.7389
35	0.8498	water	1.0000
36	0.8448		

r- "d" Exponent

1) To determine the presence of pressure transitions, calculate the "d" exponent once every (#) feet drilled, as determined by the Operator.

   A) Plot the "d" exponent for an individual well while drilling.

   B) Establish a recognizable trend (called a normal line).

   C) When abnormal pressures are encountered, a recognizable deflection from the normal line will be generated.

   $$\mathbf{d = \log[\ R \div (60 \times N)\ ] \div \log[\ (12 \times W) \div (10^6 \times Db)\ ]}$$

   D) Where:

d	= "d" exponent
R	= penetration rate in feet per hour
N	= rotary speed in rotations per minute
W	= weight on the bit in pounds
Db	= diameter of the bit in inches

s- Sizing Bit Nozzles

1) *Rule of thumb - Keep mud in laminar flow around the drill string by using the proper nozzle sizes, flow rates and pump pressures.*

2) Determine the Following:

   A) the desired hydraulic horsepower per square inch of the bit face area (**HHP/inch²**) for the bit run

   B) the maximum pump output (**Qmax**) to be used

      a) Do not exceed the pump limitations at 95% efficiency and critical flow rate (**Qc**).

   C) the maximum surface pressure (**psi Max**) allowable

3) With the above information, calculate the following:

   A) Calculate the total hydraulic horsepower (**HHPt**) to be used at the bit.

   $$\text{HHPt} = [\,(\text{HHP/inch}^2) \times \text{bit size}^2\,] \div 1.27$$

   B) Calculate the total drill string pressure drop (**delta Ps**).

   $$\text{delta Ps} = [\,(0.000077 \times MW^{0.8} \times Q^{1.8} \times Cp^{0.2}) \div \text{pipe ID(inch)}^{4.8}\,] \times \text{length(ft)}$$

      a) This calculation must be performed for every length of drill pipe having a different ID.

      b) Total the pressure drops for all different ID sections.

   C) Calculate the pressure drop to be available at the bit (**delta Pb**).

   $$\text{delta Pb} = \text{psi Max} - [\,\text{delta Pann} + \text{delta Ps}\,]$$

      a) If the annular pressure drop (**delta Pann**) is unknown, estimate it by using: $0.1 \times \text{psi Max} = \text{delta Pann}$

   D) Calculate the actual flow rate (**Q**) to be used.

   $$Q = [\,\text{HHPt} \times 1{,}714\,] \div \text{delta Pb}$$

   E) Calculate the equivalent nozzle area (**X**) in square $^1/_{32}$.

   $$X = [\,(156.5 \times Q^2 \times MW) \div \text{delta Pb}\,]^{0.5}$$

      a) Convert **X** to the number and size of nozzles to be used, or to the total nozzle area in square inches.

      Nozzle size = square root of [X ÷ 3]

         1. The nozzle size will most likely include a decimal fraction.
         2. This fraction(0.f) times 3, when rounded to the nearest whole number, will dictate how many nozzles should be one $^1/_{32}$ larger than the nozzle just calculated.
         3. For example: calculated nozzle size = 11.<u>7</u>
            0.7 x 3 = 2.1
         4. Round 2.1 down to 2.
            A. This means 2 nozzles should be $^{12}/_{32}$ in size and the original calculated nozzle should be $^{11}/_{32}$ in size.

t- Maximum Bit Weight Available

1) General

   A) In order to avoid running the drill string in compression, the top 10% to 15% of the drill collars should be maintained in tension with the drill pipe.

   B) The drill collars' weight in mud should be noted.

2) Method

   A) In order to insure that this neutral point is in the top of the stiff drill collar assembly, determine the buoyed weight of the drill collar assembly and calculate the maximum available bit weight (**Max Wb**).

   Max Wb = buoyed drill collar weight(lbs) ÷ SF

      a) Where:
         SF = the safety factor desired
         (10% safety factor = 1.1, 15% safety factor = 1.15)

u- Power

1) Force

A) Force = Pressure(psi) x Area($inch^2$)

B) Pressure = Force(lbs) ÷ Area($inch^2$)

2) Pound-force

lbf = lbm x 32.15

A) Where:

lbf = pound-force
lbm = pound-mass

3) Horsepower

HP = ft-lb ÷ 33,000

A) Where:

HP = horsepower
ft-lb = foot-pounds of work per minute

4) Hydraulic Horsepower

A) Where:

HHP = hydraulic horsepower
gpm = gallons per minute
bpm = barrels per minute

HHP = [gpm x Pressure(psi)] ÷ 1,713.6

HHP = [bpm x Pressure(psi)] ÷ 40.8

HHP = 0.02448 x bpm x Pressure(psi)

v- Pressure-Volume-Temperature

1) Charles' Law

P2 ÷ P1 = T2 ÷ T1

A) Where:

P2 = absolute pressure after a change in temperature
P1 = initial absolute pressure
T2 = absolute temperature after a change in pressure
T1 = initial absolute temperature

B) Volume of gas must remain the same.

2) Boyle's Law

P1 x V1 = P2 x V2

A) Where:

P1 = initial absolute pressure
V1 = initial volume of gas
P2 = absolute pressure after a change in volume
V2 = volume of gas after a change in pressure

B) Temperature must remain the same.

3) Ideal Gas Law

[P1 x V1] ÷ [P2 x V2] = T1 ÷ T2

A) Where:

P1 = original absolute pressure
P2 = final absolute pressure
V1 = original volume
V2 = final volume
T1 = original absolute temperature
T2 = final absolute temperature

4) Temperature

A) -273 °C = absolute zero

B) -460 °F = absolute zero

w- Temperature Conversion Factors

To Convert:	To:	Use:
Degree Celsius	Degree F	[°C + 0.56] + 32
	K	°C + 273.15
	Degree R	[°R - 491.67] + 1.8
Degree Fahrenheit	Degree C	[°F - 32] + 1.8
	K	[°F + 459.67] + 1.8
	Degree R	°F + 459.67
kelvin	Degree C	K - 273.15
	Degree F	[1.8 x (K - 273.15)] + 32
	Degree R	1.8 x K
Degree Rankine	Degree C	[°R - 491.67] + 1.8
	Degree F	°R - 459.67
	K	°R + 1.8

x- Density and Specific Gravity

1) Specific Gravity or Relative Density

SpGr = Ds + Dw

Ds = Dw x SpGr

A) Where:

SpGr = specific gravity

Ds = density of a substance, or weight per volume of a substance in: lbs/ft^3 ; kg/m^3 ; g/cm^3

Dw = density of pure water, or weight per volume of pure water in: lb/ft^3 ; kg/m^3 ; g/cm^3

2) API Gravity

Degrees API = [141.5 + Specific Gravity] - 131.5

3) Densities of some Solids, Liquids, and Gases

A) Solids in pounds per foot^3

aluminum	165.6
gold	1,206.2
ice	56.9
iron	@ 485.0
lead	712.5
mercury	846.0
wood	@ 50.0

B) Liquids in pounds per foot^3

gasoline	46.8
kerosene	50.0
sulfuric acid	125.0
sea water	64.3
pure water	62.5

C) Gases in pounds per foot^3

air	0.075
carbon monoxide	0.0734
hydrogen	0.0053
nitrogen	0.0737
oxygen	0.084

D) Specific Gravity based on Air

air	1.0
carbon monoxide	0.979
hydrogen	0.071
hydrogen sulfide	1.1895
nitrogen	0.0983
oxygen	1.12

y- Gradients

1) Dip Gradient (Texas Gulf Coast)

A) 130' per mile towards the continental margin from the Vicksburg Flexure

B) 250' per mile towards the basin from the Vicksburg Flexure

2) Temperature Gradient (Texas Gulf Coast)

A) 2 degrees F per 100' of true vertical depth (maximum extremes)

B) usually runs from 1 to 1.8 degrees F per 100' of depth

a) 1.5 to 1.6 degrees F from the surface down to 7,000'

b) 1.7 to 1.8 degrees F from 7,000' down to 12,000'

c) 1.8 to 2.0 degrees F from 12,000' down to 20,000'

3) Fracture Gradient (Texas Gulf Coast)

A) 0.70 to 0.80 pound per square inch/foot of depth

a) can vary from 0.50 to 1.10 even at shallow depths

b) at 20,000' use 1 pound per square inch/foot of depth

B) Yegua on the Texas Gulf Coast can run as high as 0.86 psi/ft.

C) Wilcox in South Texas can run as high as 0.96 psi/ft.

4) Hydrostatic Gradient

A) 0.368 pound per square inch/foot of depth for 35 degree API oil

B) 0.433 pound per square inch/foot of depth for fresh water

C) 0.444 pound per square inch/foot of depth for sea water

D) 0.465 pound per square inch/foot of depth for salt water

E) 0.520 pound per square inch/foot of depth for saturated salt water

F) **psi/ft =**

a) **MW(ppg) ÷ 19.24**

b) **SpGr of mud ÷ 2.31**

c) **MW(ppg) x 0.052**

G) **lbs/foot^3 =**

a) **MW(ppg) ÷ 0.1337**

b) **MW(ppg) x 7.48**

H) **ppg =**

a) **MW(lbs/ft^3) ÷ 7.48**

b) **MW(lbs/ft^3) x 0.1337**

5) Gas Weight Gradient

A) 0.03 pound per square inch/foot of depth

B) can range as high as 0.10 pound per square inch/foot in some areas

6) Overburden

A) 1 pound per square inch/foot of depth

D- WELL CONTROL

a- High Pressure Detection {51}

1) Monitor the drilling rate.
- A) The drilling rate is a function of:
  - a) bit type.
  - b) bit size.
  - c) weight on bit.
  - d) differential pressure.
  - e) water loss properties of the drilling mud.

2) Plot the "d" exponent with depth.

$$d = \log[\,R \div (60 \times N)\,] \div \log[\,(12 \times W) \div (10^6 \times Db)\,]$$

A) Where:

d	= "d" exponent
R	= penetration rate in feet per hour
N	= rotary speed in rotations per minute
W	= weight on the bit in pounds
Db	= diameter of the bit in inches

3) Plot the corrected "d" exponent with depth.

$$dc = d \times [\,\text{normal MW} \div \text{MW being used}\,]$$

A) Where:

dc	= corrected "d" exponent
d	= "d" exponent
9	= normal mud weight in soft rock country
8.25	= normal mud weight in hard rock country

B) Plot the "d" exponent and the corrected "d" exponent together.

4) Watch the torque of the drill pipe.
- A) decreases in high pore pressure

5) Watch the drag of the drill pipe.
- A) increases in high pore pressure

6) Watch the level of gas in the mud.
- A) Increases in trip gas, connection gas and background gas indicate a change in formation pressure.

7) Taking a kick is the most obvious sign of encountering a higher formation pressure.

8) Watch for an increase in mud temperature.

9) Chlorides increase with depth under normal conditions.
- A) In high pressure regimes the chlorides precipitate (fall out) as a dissolved solid, decreasing the chloride level.

10) Watch for pit level gains.

11) Hole fill-up volumes
- A) When pulling out of the hole, fill up after pulling three stands.
- B) The volume that it takes to fill the hole should be the same as the volume displaced by the three stands.
- C) It is best to use a trip tank.

12) Monitor the drilling mud flow rate.

13) Shale Density
- A) increases with depth
- B) decreases in high pressures

14) Shale Composition
- A) Montmorillonite clay levels increase in higher pressures.
  - a) increases the cation exchange capacity of the mud
  - b) shows up on a methylene blue test (MBT)
  - c) indicates higher than normal pressures

15) Volume of Cuttings
   A) Shale tends to "pop" off of the formation in higher pressures rather than waiting to be cut by the drill bit.
      a) adds a considerable volume of shale to the cuttings
      b) easily recognized by its characteristic banana-shaped splinters

16) The values from **1)**, **2)**, **3)**, **6)**, **8)**, **9)**, and **13)** are particularly important because they can be measured, calculated, and/or plotted versus depth throughout the job.

b- Kick

1) During Drilling
   A) Causes
      a) mud weight too low
      b) loss of circulation
      c) bit encounters a zone with abnormally high pressure
   B) Indicators
      a) a decrease in string weight
      b) a decrease in the pump pressure
      c) a change in mud properties
      d) a gain in pit volume
      e) an increase in the flow rate
      f) an increase in the pump rate
      g) an increase in the penetration rate

2) During Tripping
   A) Causes
      a) not keeping the hole full
      b) swabbing
   B) Indicators
      a) an incorrect amount of mud to fill the hole to compensate for the removal of the pipe

c- Well Control Drill - while Drilling

1) Activate the flow sensor to:
   A) show a gain or an increase in pit volume.
   B) indicate a flow.
2) Announce that the well is flowing.
3) The Driller must:
   A) pick up the kelly.
   B) shut off the pump.
   C) check for flow if called for by company policy.
4) If the well does not flow, the time taken for the drill should be recorded.
5) The well kick alarm is sounded.
6) The well is closed in based on company procedure.
   A) Normally:
      a) Clear the tool joint from the BOP stack.
      b) Stop pumps.
      c) Check for flow.
      d) Open the choke line manifold.
         1. If offshore, open the riser choke line.
      e) Close the annular preventer.
      f) Close the choke.
      g) Record pressures.
      h) Have the crew stand by for further instructions.
   B) *Make a Contingency Plan!*
      a) Set up a means of communication with local residents.
      b) Allow only key people to become involved in well control.
      c) In case the hands get scattered, select a rally point such as a terrain or structural feature easily recognized by everyone.
      d) Define simple hand and arm signals for use during well control.
      e) Allow no fire sources within close proximity to the rig.
      f) If equipment is moved in to assist in well control, rig them up as far from the rig as possible.

7) When the kick alarm sounds the following should occur.
   A) Stop all welding.
   B) Extinguish fires.
   C) Allow no smoking.
   D) All personnel move to their stations.

d- Well Control Drill - while Tripping

1) Activate the flow sensor to:
   A) show a gain or an increase in pit volume.
   B) indicate a flow.
2) Announce that the well is flowing.
3) Driller lands pipe on the slips.
4) The stabbing valve or full-opening valve should be made up on the pipe.
   A) Close the valve.
   B) Some inside BOP valves allow simultaneous:
      a) stripping back to bottom.
      b) pumping.
5) The well kick alarm is sounded.
6) The well is closed in based on company procedure.
   A) Normally:
      a) Clear the tool joint from the BOP stack.
      b) Open the choke line manifold.
         1. If offshore, open the riser choke line.
      c) Close the annular preventer.
      d) Close the choke.
      e) Have the crew stand by for further instructions.
7) When the kick alarm sounds the following should occur.
   A) Stop all welding.
   B) Extinguish fires.
   C) Allow no smoking.
   D) All personnel move to their stations.

E- PRESSURE CONTROL SYSTEM

a- Casing:

1) should be able to withstand any anticipated wellhead pressures.
2) must support the weight and bending loads of the preventer stack.
3) must be bonded to the formation with good cement.

b- Casinghead:

1) attaches the BOP equipment to the casing.
2) has threaded or open-faced outlets for choke and kill lines.
3) should have a working pressure rating that either meets or exceeds the maximum anticipated surface pressure.
4) should equal or exceed the bending strength of the outermost casing, to which it is attached.
5) should equal the mechanical strength of the pipe to which it is attached.
6) should have adequate strength to support the weight of any casing or tubing that is hung inside of it.

c- Drilling Spool(s):

1) connects the choke and kill lines to the BOP stack.
   A) In cold climates, use antifreeze in the system to keep the choke lines from freezing while idle.
2) provides space between the pipe rams to allow ram-to-ram stripping of tool joints through the BOP stack.
3) ID should equal the maximum bore diameter of the outer-most casinghead.
4) pressure ratings should be the same as the BOPs.
5) side outlets should be
   A) flanged.
   B) no smaller than a 2 inch ID.

C) If designing for pressures greater than 10,000 psi:
  a) at least two outlets should be used.
  b) at least one should be a 3 inch ID.

D) Some BOPs have side elements that accommodate choke and kill lines.
  a) If sand erodes these BOP outlets, they are expensive to fix.
  b) Most Operators prefer to hook choke and kill lines to the drilling spool because it is cheaper to replace.

d- Ram Blow-Out Preventers

1) Pipe rams close around a specific size pipe.
2) Blind rams close in on an empty well.
3) Shear rams are a special type of blind ram with shear blades attached.
  A) will shear pipe present in the well only in the tube, not in the tool joint.
4) Variable bore rams are:
  A) available.
  B) can close on a range of different pipe sizes.

e- Annular Blow-Out Preventers:

1) close off the wellbore with anything (tool joint, tube, or kelly) in the preventer, using rubber compression seals.
  A) Depending on the pressures, these are closed just before closing the pipe rams.
2) can be used to strip the pipe back to TD while the well pressure is held by the annular preventer.
3) Most Common Types
  A) Shafer
  B) Hydrill
  C) Cameron

f- Choke and Kill Flow Lines

1) All lines and fittings must be rated at pressures greater than or equal to the working pressures of the remainder of the system.
  A) Lines should be:
    a) as straight as possible.
    b) anchored.
2) Choke
  A) The choke line connects the outlet of the BOP or drilling spool to the choke manifold.
    a) It can consist of two lines and as many valves.
      1. If one cuts out (fails), the other is used while the first is being replaced.
    b) It can also consist of one 4 inch line.
  B) A choke manifold is used to maintain back pressure on the wellbore by routing the annular flow through a choke.
  C) A power operated valve is usually located downstream of the BOPs where it can be remotely opened to the choke on the relief line.
    a) This prevents anyone from having to go under the rig while there is pressure on the well.
  D) A "blooie-line" is normally included as a straight-through large diameter pipe used to vent large volumes of fluid in the event a choke is holding more pressure on the surface equipment than it is rated to.
3) Kill
  A) The kill line is used to circulate fluid into the annulus.
  B) The kill manifold connects the rig pumps to the stack outlets.
    a) A check valve should be included to keep the well from flowing into the pumps but should still allow fluid from the pumps to enter the wellbore.
    b) If extremely high pressures are expected, a tee with a check valve is placed in the line so that pump trucks can be attached if needed.

g- Accumulator:

1) used to close the rams or other preventers in a matter of seconds.
   A) Nitrogen pressure is built up in a tank or chamber.
      a) stored until needed
   B) Working pressures are between 1,200 and 1,500 psi.
      a) can sometimes range much higher
2) capable of discharging at pressures high enough (greater than 1,500 psi) to damage the BOPs.
   A) To control this, a pressure regulator is placed between the accumulator and the BOPs.

h- Blow-Out Preventer Stack Configurations

1) Variable bore rams can be used in configurations **3)** through **7)** below and are sometimes highly recommended.
2) The group of letters (e.g. - SRRA) after each stack name is a listing of the stack elements from the ground up.
   A) Where:
      A = annular
      R = ram
      S = spool

3) Three-Preventer Stack - SRRA
   A) From the rig floor down:
      a) bell nipple
      b) annular
      c) blind rams
      d) pipe rams
      e) spool
   B) Characteristics
      a) can strip:
         1. through annular
         2. between annular and pipe rams
      b) can pump or bleed off pressure without pipe
      c) can circulate with:
         1. annular
         2. pipe rams
         3. blind ram cavity if blind rams are replaced with pipe rams
      d) can use double preventer
   C) Disadvantages
      a) no preventer below the spool for an emergency

4) Three-Preventer Stack - RSRA
   A) From the rig floor down:
      a) bell nipple
      b) annular
      c) blind rams
      d) spool
      e) pipe rams
   B) Characteristics
      a) can strip:
         1. through annular
         2. between annular and pipe rams
         3. between blind ram cavity and lower pipe rams if blind rams are replaced with pipe rams
      b) can pump or bleed off pressure without pipe
      c) can circulate with:
         1. annular
         2. blind ram cavity if blind rams are replaced with pipe rams
      d) pipe rams below spool for emergency
   C) Disadvantages
      a) may have to strip through emergency preventer below the spool
      b) have to change out blind rams to circulate out through the choke

5) Four-Preventer Stack - SRRRA (single size string)
   A) From the rig floor down:
      a) bell nipple
      b) annular
      c) blind rams
      d) pipe rams
      e) pipe rams
      f) spool
      g) casing spool
   B) Characteristics
      a) can strip:
         1. through annular
         2. between annular and either pair of pipe rams
         3. between blind ram cavity and lower pipe rams if blind rams are replaced with pipe rams
      b) can pump or bleed off pressure without pipe
      c) can circulate with:
         1. annular
         2. either pair of pipe rams
         3. blind ram cavity if blind rams are replaced with pipe rams
   C) Disadvantages
      a) no preventer below spool for emergency

6) Four-Preventer Stack - RRSRA (single size string)
   A) From the rig floor down:
      a) bell nipple
      b) annular
      c) pipe rams
      d) spool
      e) blind rams
      f) pipe rams
   B) Characteristics
      a) can strip:
         1. through annular
         2. between annular and bottom
         3. between annular and blind ram cavity if blind rams are replaced with pipe rams
         4. between upper pipe rams and blind ram cavity if blind rams are replaced with pipe rams
      b) can circulate with:
         1. annular
         2. upper pipe rams
   C) Disadvantage
      a) second set of blind rams are required to bleed off pressure or pump without pipe

7) Four-Preventer Stack - SRSRRA (single size string)
   considered by many to be the best
   A) From the rig floor down:
      a) bell nipple
      b) annular
      c) blind rams
      d) pipe rams
      e) spool
      f) pipe rams
      g) casing spool
   B) Characteristics
      a) can strip:
         1. through annular
         2. between annular and either pair of pipe rams
         3. between pipe rams
         4. between blind ram cavity and lower pipe rams if blind rams are replaced with pipe rams
      b) can pump or bleed off pressure without pipe

c) can circulate with:
1. annular
2. upper pipe rams
3. blind ram cavity if blind rams are replaced with pipe rams

C) Disadvantages
a) must use bottom rams for ram-to-ram stripping

8) Four-Preventer Stack - RRSRA (tapered string)

A) From the rig floor down:
a) bell nipple
b) annular
c) blind rams
d) spool
e) small pipe rams
f) large pipe rams

B) Characteristics
a) can strip:
1. through annular
2. between annular and small pipe rams
3. between annular and large pipe rams
4. between blind ram cavity and small pipe rams if blind rams are replaced with pipe rams
5. between blind ram cavity and large pipe rams if blind rams are replaced with pipe rams

b) can pump or bleed off pressure without pipe
c) can circulate with:
1. annular
2. blind ram cavity if blind rams are replaced with pipe rams

C) Disadvantages
a) must change out rams for flexibility

9) Five-Preventer Stack - RSRRRA (tapered string)

A) From the rig floor down:
a) bell nipple
b) annular
c) blind rams
d) small pipe rams
e) large pipe rams
f) spool
g) large pipe rams

B) Characteristics
a) can strip:
1. through annular
2. between annular and pipe rams
3. between large pipe rams
4. between blind ram cavity and any large ram if blind rams are replaced with pipe rams

b) can pump or bleed off pressure without pipe
c) can circulate with:
1. annular
2. large or small pipe rams above spool
3. blind ram cavity if blind rams replaced with pipe rams

C) Disadvantage
a) must change rams to strip ram-to-ram without using bottom rams

i- Blow-Out Preventer Testing

1) Test after BOP installation.
2) BOPs should test up to a minimum of 70% and up to 100% of rated working pressures, except for Hydrills.
3) Test before drilling out after each new string of casing is set.

4) Test at least once a week.
5) Test following repairs that require disconnecting a pressure seal.
6) Test after a ram change or annular packing element change.
7) Test without pressure when:
    A) pipe rams are closed on pipe once each day.
    B) blind/shear rams are closed on open hole once each trip.
    C) annular is closed on pipe once each week.

F- BITS { 52, 53 }

All types and numbers are from Hughes catalog.

a- Bit Types

1) Journal Bearing
    A) does not contain rollers
    B) contains a solid journal pin mated to the inside surface of the cone
        a) This journal becomes the load carrying element of the bearing.
    C) All bearing elements are uniformly loaded.
    D) Higher weights and rotary speeds can be run without decreasing bearing lift.

2) Sealed Bearing
    A) Each bit leg consists of a:
        a) grease reservoir.
        b) double-sealed thick rubber compensator.
        c) connecting passage and seal.
    B) The pressure in the bearing is equalized with the pressure of the drilling fluid.
    C) The lube reservoir is sealed with a solid cap that prevents leakage of drilling fluid into the lube system.
    D) Blockage often occurs in top-vented systems when:
        a) pulling up to make a connection.
        b) cuttings settle while drilling.

3) Non-sealed Bearing
    A) used in steel tooth bits to drill top hole sections where:
        a) trip time is low
        b) rotary speed is high
    B) The radial load on the cutter is absorbed by the roller face.
        a) The nose bearing absorbs a lesser amount.
        b) An outward thrust is created by the:
            1. thrust surface being perpendicular to the pilot pin.
            2. thrust button.

b- Bit Teeth

1) Tungsten Carbide
    A) ovoid
    B) ogive
    C) conical
    D) chisel
    E) wedge-crested chisel
    F) scoop chisel

2) Steel
    A) soft formation bits
    B) medium formation bits
    C) hard formation bits

c- Bit Condition - Possible Causes and Remedies {39}

1) Excessive Bearing Wear	Excessive rotary speed	Slow rotary speed
	Excessive rotating time	Reduce hours
	Excessive weight on bit	Less weight on bit
	Excessive sand in mud	Remove sand from mud
	Unstable drill collars	Stabilize drill collars
	Improper bit type	Use harder bit type that has larger bearings
2) Excessive Broken Teeth	Improper bit type	Use different bit, based on rows of teeth most worn on the old bit
	Improper bit break-in procedure	Break in properly
	Excessive weight on bit	Use lighter weight on bit Consider using a shock sub in the drill string
3) Unbalanced Tooth Wear	Improper bit type	Same as above
	Improper bit break-in procedure	Same as above
4) Excessive Tooth Wear	Excessive rotary speed	Slow rotary speed
	Improper bit type	Use harder bit with more teeth
	Use of non-hard-faced type bit	Use bit with harder teeth
5) Excessive Cupping of Tooth Crests	Double hard-faced teeth	Use bit with tipped teeth
	Insufficient weight	Use more weight on bit
	Improper use of bit	Use different bit type
6) Bradding of Teeth (tooth ends are dented)	Excess weight on dull bit	Change bit sooner
	Improper use of bit	Use different bit type
7) Fluid Cut Teeth and Cones	Excessive circulation rates	Reduce circulation rates
	Too much sand in mud	Remove sand from mud
8) Excess Undergauge	Improper bit type	Use bit that has a greater gauge protection
	Excessive rotating time	Reduce hours

9) Skidded due to Balling	Excessive weight on bit	Lighter weight on bit
	Improper use of bit	Use bit with teeth widely spaced
	Insufficient circulation rate	Increase circulation rate

d- Bit Selection

1) Tungsten Carbide Tooth Bits

A) Soft Formations: clay, soft limestone, salt, sand, shale, red beds

a) Bit types:

1. Hughes

A. Journal Bearing
- a. J11
- b. J22
- c. J33
- d. HH33

B. Sealed Bearing
- a. X11
- b. X22
- c. X33

2. Reed

A. Journal Bearing
- a. H551
- b. FP51A
- c. FP52
- d. FP53
- e. HPSM
- f. HP54B

B. Sealed Bearing
- a. S52
- b. S53

3. Security

A. Journal Bearing
- a. S82F
- b. S82CF
- c. S84F
- d. S84CF
- e. S86F
- f. S86CF
- g. S88F
- h. S88CF

B. Sealed Bearing
- a. S84
- b. S86
- c. S88

4. Smith

A. Journal Bearing
- a. F1
- b. A1
- c. F2
- d. F27
- e. F3
- f. F37
- g. F15

B. Sealed Bearing
- a. 2JS
- b. 3JS

B) Medium Formations: dolomite, limestone, sand, hard shale

a) Bit Types:

1. **Hughes**
   - A. Journal Bearing
     - a. J44
     - b. J55R
     - c. J55
     - d. HH44
     - e. HH55
   - B. Sealed Bearing
     - a. X44
2. **Reed**
   - A. Journal Bearing
     - a. FP62
     - b. HPM
     - c. FP62B
     - d. HPMH
     - e. FP63
   - B. Sealed Bearing
     - a. S62
     - b. S62B
     - c. S63
3. **Security**
   - A. Journal Bearing
     - a. M84F
     - b. M84CF
     - c. M89TF
     - d. M89F
     - e. M90F
4. **Smith**
   - A. Journal Bearing
     - a. F4
     - b. F45
     - c. F47
     - d. F5
     - e. F57
   - B. Sealed Bearing
     - a. 4JS
     - b. 5JS

C) Hard Formations: chert, dolomite, limestone, sandy shale

a) Bit types:

1. **Hughes**
   - A. Journal Bearing
     - a. J77
     - b. J99
     - c. HH77
     - d. HH99
2. **Reed**
   - A. Journal Bearing
     - a. HPH
     - b. FP73
     - c. HP83
   - B. Sealed Bearing
     - a. S73
     - b. S74
     - c. S83
3. **Security**
   - A. Journal Bearing
     - a. H87F
     - b. H88F
     - c. H100F

B. Sealed Bearing
  a. H88
  b. H99
  c. H100

4. Smith

A. Journal Bearing
  a. F7
  b. F9

2) Steel Tooth Bits

A) Soft Formations: clay, soft limestone, salt, sand, shale, red beds

a) Bit types:

1. Hughes

A. Journal Bearing
  a. J1
  b. J2
  c. J3
  d. JD3

B. Standard Bearing (non-sealed)
  a. OSC-3AJ or R1
  b. OSC-3J or R2
  c. OSC-1GJ or R3

C. Sealed Bearing
  a. X3A
  b. X3
  c. X1G
  d. XDG

2. Reed

A. Journal Bearing
  a. HP11
  b. HP12
  c. HP13

B. Standard Bearing (non-sealed)
  a. Y11
  b. Y12 or Y12T
  c. Y13 or Y13T

C. Sealed Bearing
  a. S11
  b. S12
  c. S13
  d. S13G

3. Security

A. Journal Bearing
  a. S33SF
  b. S33F
  c. S44F

B. Standard Bearing (non-sealed)
  a. S3SJ
  b. S3J or S3T
  c. S4J or S4T

C. Sealed Bearing
  a. S33S or S33SG
  b. S33
  c. S44
  d. S44G

4. Smith

A. Journal Bearing
  a. FDS
  b. FDT
  c. FDG

B) Medium Formations: dolomite, limestone, sand, hard shale

a) Bit types:

1. Hughes

A. Journal Bearing
- a. J4
- b. JD4

B. Standard Bearing (non-sealed)
- a. OWV-J
- b. OW4-J
- c. WO

C. Sealed Bearing
- a. XV
- b. XDV

2. Reed

A. Journal Bearing
- a. HP21
- b. HP21G

B. Standard Bearing (non-sealed)
- a. Y21 or Y21G
- b. Y22

C. Sealed Bearing
- a. S21
- b. S21G
- c. S23G

3. Security

A. Journal Bearing
- a. M44NF
- b. M44LF

B. Standard Bearing (non-sealed)
- a. M4N
- b. M4L

C. Sealed Bearing
- a. M44N
- b. M44NG
- c. M44L

4. Smith

A. Journal Bearing
- a. FV

B. Standard Bearing (non-sealed)
- a. V2
- b. V2H

C. Sealed Bearing
- a. SV
- b. SVH

C) Hard Formations: chert, dolomite, limestone, sandy shale

a) Bit types:

1. Hughes

A. Journal Bearing
- a. J7
- b. J8
- c. JD8

B. Standard Bearing (non-sealed)
- a. W7J
- b. W7R-2J

2. Reed

A. Journal Bearing
- a. HP31G

B. Standard Bearing (non-sealed)
- a. Y31
- b. Y31G

C. Sealed Bearing
- a. S31G

3. Security
- A. Journal Bearing
  - a. H77F
  - b. H77CF
- B. Standard Bearing (non-sealed)
  - a. H75
  - b. H75G
- C. Sealed Bearing
  - a. H77
  - b. H77SG
  - c. H77C

4. Smith
- A. Standard Bearing (non-sealed)
  - a. L4
  - b. L4H
- B. Sealed Bearing
  - a. SL4H

e- Standard Bit Sizes (inches)

$3\,^3/_4$	$6\,^3/_4$	$12\,^1/_4$
$3\,^7/_8$	$7\,^7/_8$	$13\,^1/_2$
$4\,^1/_8$	$8\,^3/_8$	$13\,^3/_4$
$4\,^3/_4$	$8\,^1/_2$	$14\,^3/_4$
$5\,^7/_8$	$8\,^3/_4$	$17\,^1/_2$
6	$9\,^1/_2$	20
$6\,^1/_8$	$9\,^7/_8$	24
$6\,^1/_4$	$10\,^5/_8$	26
$6\,^1/_2$	11	

f- Cost Formulae { 39 }

1) Drilling costs are generally lower in the summer months.
   - A) More are rigs available so drilling bids are more competitive.
   - B) Weather is drier so location costs are lower.
   - C) Service companies compete more due to lower rig utilization rates.

2) Total Costs

$$TC = B + [\, R \times (T + t)\,]$$

A) Where:

TC	= total costs
B	= bit cost in dollars
R	= rig operating costs in dollars per hour
T	= drilling time in hours
t	= round-trip time in hours, from the time the old bit quit drilling until the new bit gets on bottom

3) Costs per Foot

$$C = [\, B + (R \times [T + t])\,] \div F$$

A) Where:

C	= drilling cost in dollars per foot
B	= bit cost in dollars
R	= rig operating costs in dollars per hour
T	= drilling time in hours
t	= round-trip time in hours, from the time the old bit quit drilling until the new bit gets on bottom
F	= number of feet of hole drilled by bit

g- Bit Balling

1) Usual Cause of Bit Balling

A) High bit weights in sticky formations such as gummy shales will cause the cuttings to adhere to the teeth surface because of hydrogen bonding.

a) Hydrogen bonding occurs when a molecular layer of water that is adsorbed on the shale surface sticks to the layer of water adhering to the steel surface.

G- DIRECTIONAL DRILLING { 54 }

a- Applications

1) multiple wells from artificial structures
2) reservoir optimization through:
   A) drilling along fracture planes
   B) exposing the well bore to as much of the reservoir as possible
   C) Both A) and B) will theoretically improve production because the radial drainage area exposed to the producing formation is increased significantly.
3) inaccessible locations
4) remedial sidetracking or straightening
5) salt dome drilling
   A) gets under the lip that sometimes forms on the top of a salt dome and traps the production
6) relief wells

b- Definitions

Vertical Hole - deviating less than 3 degrees from vertical.

Drift - horizontal component of the distance from the surface site to any certain point in the hole, usually the bottom of the hole or mid-point of the zone.

Turn - change in bearing of the hole. Usually spoken of as the right or left turn. Orientation is that of an observer who views the well course with respect to North.

Dogleg - an exceptionally sharp turn, measured by vector plotting of the total included angle.

Deflected Hole - artificially caused to deviate from vertical. Bearing and angle are predetermined to some extent.

Deviation - (sometimes known as the horizontal deviation) is usually calculated with respect to the surface location.

Kick-off Point - the depth at which the deviation is started.

Rate of Inclination - can be referred to as a "build-up" or a "drop-off" and is normally expressed in degrees per 100 feet.

Build-up - that portion of the hole in which the drift angle is increased. Usually expressed as the rate of angular increase per unit of drilled depth.

Drift Angle - a more or less constant angle at which the hole is carried after sufficient angle has been obtained in the build-up.

Drop-off - that portion of the hole in which the drift angle is reduced, also the rate of this reduction.

Well Depth - measured depth of the hole. Usually measured from the kelly bushing.

Vertical Depth - vertical component of the measured well depth.

True Vertical Depth - the depth of the well in a vertical plane.

Usable Vertical Depth - the difference between the depth at the kick-off point and the true vertical depth.

Course Length - distance measured in the bore hole.

c- Planning Considerations

1) Detail the size and shape of the target area.
- A) The greater the restrictions, the more expensive the job will be.

2) Location Selection
- A) Take advantage of the natural deviation tendencies.
  - a) When drilling through hard formations, the bit will tend to align itself perpendicular to the bedding planes.
  - b) The bit will tend to "walk" up-dip.
    - 1. assists in angle building
  - c) The bit will align itself with bedding planes in dips of 45 degrees or greater.

3) Hole Size Selection
- A) Large diameter holes are easier to control than small diameter holes.
- B) Slimhole drilling calls for small, flexible drill collars.
  - a) Small collars limit the weight that can be placed on the bit.
  - b) The formation tendencies mentioned above will have a greater impact on the directional control of a small hole.

4) Casing Program
- A) Most directional holes can be drilled with the same casing program that the straight holes follow in the area.
- B) In some cases, high angle wells will need an intermediate string in order to maintain hole integrity after the angle is built.
- C) A consideration in highly deviated holes is the use of drill pipe protectors to reduce wear on the casing and the drill pipe.

5) Mud Program
- A) Mud properties impact greatly on the drag of the drill pipe which in turn, impacts on the control of the deviation angle.
- B) The use of friction-reducing agents is normally recommended.
- C) Viscosity and mud weight are the two critical parameters that have to be controlled at all times.
- D) Keep solids to an absolute minimum.

6) Drill String Components
- A) The survey instrument is usually seated immediately above the bit, inside the monel collar.
  - a) usually neutralizes the residual magnetism in the rest of the string
- B) The casing from adjacent wellbores can be subjected to the drill collar magnetism and therefore have a residual effect on the surveys.

d- Hole Patterns

1) Type I - The deflection is obtained from a shallow depth and is held constant until TD.

2) Type II - A deflection is taken at a shallow depth and is returned to vertical nearing the target depth (called an "S" curve pattern).

3) Type III - The well is held vertical until deep. As the target depth is neared, it is deviated to the target.

e- Planning

1) Selection of the Kick-off Point
   - A) The determining factor is the drift angle necessary to maintain the desired deviation.
   - B) Correct initial deflection and direction is essential from the start.
   - C) In most cases, drift angles of 15 to 45 degrees are easier to maintain since they allow more leeway in the selection of a kick-off point and give greater angle stability than do small 5 to 10 degree angles.
   - D) Decide on acceptable limits of lateral displacement.
     - a) All directional plans must allow for displacement of a few degrees on either side of a straight horizontal line connecting the surface and the target location.
     - b) The hole must be drilled within an imaginary cylinder surrounding the axis of the proposed well.

f- Calculation of the Directional Plan

1) Where:

   Dev = horizontal deviation
   KOP = kick-off point
   MD = measured well depth
   VD = vertical depth
   TVD = true vertical depth

2) Calculation of the Type I or Type III Hole Pattern
   - A) Obtain the measured well depth.
   - B) Decide on the true vertical depth and the kick-off point.
   - C) Calculate the usable vertical depth.

     usable VD = TVD - KOP

   - D) Select the correct composite build-up chart.
     - a) from the directional drilling chart books
     - b) based on:
       1. well depth
       2. kick-off point
       3. deviation angle
     - c) At the intersection of the vertical scale (usable vertical depth) and the horizontal scale (horizontal deviation) find the maximum angle at completion of build-up.
   - E) Calculate the actual depth at completion of build-up.

     actual depth = TVD + KOP

   - F) Find the measurements below the build-up by solving the values of the remaining triangle.
     - a) Calculate the actual vertical depth below build-up.

       actual VD = TVD - VD

     - b) Calculate the total measured depth.

       MD at build-up +
       [VD below build-up + cosine of the maximum angle]

3) Calculation of the Type II Hole Pattern
   - A) Select the correct composite build-up chart.
   - B) Find the usable vertical depth.
   - C) From the chart:
     - a) find the maximum angle at the completion of build-up.
     - b) obtain the measured depth and the vertical depth at completion of build-up.
     - c) find the measured depth, vertical depth, and deviation necessary to bring the well back to vertical.

D) Solve the values of the triangle in the middle of the plat.

a) **Tangent of the maximum angle =**

[Dev - (Dev for build-up + Dev for drop-off)] +

[usable VD - (VD at build-up + VD at drop-off)]

b) **The measured length of the locked-in segment =**

usable VD -

[(VD at build-up + VD at drop-off) +

cosine of the maximum angle]

c) **Total measured depth =**

MD at KOP + MD during build-up +

MD of locked-in segment + MD during drop-off

g- Deflection Tools

1) Selection of the proper deflection tool depends largely on the type of formations that exist at the kick-off point.

2) Standard Removable Whipstock:

A) consists of a long steel wedge that is concave on one side.

a) The purpose of the concave portion is to hold and guide the drilling assembly.

3) Circulating Whipstock:

A) very similar to **2)**, except that drilling mud can be pumped through the drilling assembly to dress off the top of the plug prior to landing the whipstock.

B) Both **2)** and **3)** are run with a bit, a stabilizer, and an orienting sub all attached with a shear pin.

a) Once the assembly is on bottom and oriented, weight is applied to the assembly.

1. shears the pin
2. sets the whipstock

b) A rat hole (pilot hole) is drilled to about 16 feet below the base of the whipstock.

c) A regular size bit is reamed down the rat hole.

d) A survey is made of the deflection.

4) Permanent Casing Whipstock:

A) consists of: starting mill; orienting sub; drill pipe.

B) used when the sidetrack is from a cased hole.

a) left as a permanent fixture

C) anchored at the appropriate depth.

D) After the whipstock is anchored, it frees up the mill.

a) The mill rotates and cuts a hole through the casing wall.

b) After this initial hole has been cut, another mill is run.

1. About four feet of open hole is drilled.

c) A survey is run.

d) The standard drilling assembly is run.

5) Knuckle Joint:

A) designed to sidetrack a well without the use of a whipstock.

B) consists of a spring loaded universal joint and bent subs located in the drill string.

C) limited by orientation problems.

a) best suited for use when faced with no restrictions on the sidetrack direction

6) Jet Bit:
   - A) can be either a two- or three-cone bit that has been modified so that one of the jet openings is much larger than the others.
   - B) the most economical deflection tool but its use is restricted to soft formations.
   - C) Once on bottom, washing is commenced with the bit being spudded occasionally.
     - a) A hole is washed in the side that the large eye (jet opening) is on.
     - b) The alternating jetting (washing) and spudding is continued until the proper deflection angle is acquired.

7) Downhole Motor:
   - A) power is derived from the drilling mud that is circulated through rotors within the tool.
     - a) As mud is pumped through the tool the blades are spun.
   - B) consists of: bit; motor; bent sub and a non-magnetic drill collar; the normal drill string.
   - C) An advantage of this type of deflection tool is that the bent sub can be hydraulically activated so that a gauge hole can be drilled to the kick-off point, oriented, activated (locked into position) and drilled directionally.

h- Principles of Directional Drilling

1) Fulcrum Principle
   - A) A stabilizer is placed in the drill string just above the bit.
   - B) As more weight is applied to the bit, the change in the hole angle increases (as if a crowbar were placed next to the bit).

2) Stabilization Principle
   - A) Once the proper hole angle is built, stiff collars and plenty of stabilizers are run.
     - a) referred to as the packed hole assembly
     - b) rigid design prevents the bit from wandering off course

3) Pendulum Principle
   - A) When the hole angle has to drop-off back to the vertical, the first stabilizer above the drill bit is removed.
   - B) The remaining stabilizers keep the bottom collar away from the low side of the wall letting gravity work on the bit, thereby pulling the hole back to vertical.

i- Typical Problems of Directional Drilling

1) Lateral Drift
   - A) corrected by true rolling bits (have a zero-cone offset)
   - B) can be corrected by the use of other special downhole tools

2) Dogleg Severity
   - A) Overly severe doglegs can be detected early on by the use of regular orientation surveys.
   - B) Potential secondary effects:
     - a) keyseats
     - b) worn drill pipe
     - c) drill string damage
   - C) Slight doglegs must be reamed and re-surveyed.

j- Directional Surveying

1) Magnetic Surveys (require a non-magnetic collar)
   - A) Magnetic Single-Shot Survey
     - a) Components:
       - 1. Timing device
         - A. operates the camera at a predetermined time
         - B. usually accomplished through the use of motion sensors that send a signal when downhole motion stops

2. Camera
   A. pre-focused, loaded and housed in a special heat resistant carrier
   B. When the signal is received from the motion sensor, the camera takes a picture of the reading in the angle-indicating unit.
3. Angle-indicating unit
   A. combines a magnetic compass and a plumb bob
   B. gives the angle of inclination from vertical

b) Operation
1. Once a bit is dulled:
   A. the timer is set.
   B. the tool is placed in a protective barrel.
   C. it is run in the hole on a wireline or dropped on the dull bit.
2. At TD:
   A. the camera is activated.
   B. a picture is taken of the relative positions of the compass and the plum bob.
3. The instrument is returned to the surface.
4. The film is developed to reveal the exact direction and angle of inclination.

B) Magnetic Drop Survey
a) most economical
b) uses a 10mm film strip
c) takes several recordings at predetermined depths
d) Operation
1. The timing device is synchronized with a watch at the surface.
2. The tool is placed in its protective carrier.
3. It is dropped through the drill string and lands on the baffle plate located on the pin end of the bit.
4. As the drill string is pulled, the downhole data is recorded.
5. The film is developed.
6. Information from the developed film is transformed into survey information.

C) Open Hole Survey
a) powered by batteries
b) multiple-shot tool
c) operates with 16mm film
d) operates like the single-shot tool

2) Surveys run without the use of non-magnetic collars

A) Drift Indicator Survey
a) used to record total displacement or deviation
b) dropped on a dull bit
c) housed with shock and pressure protection through the use of a snap lock barrel
d) Operation
1. After a pre-set time has elapsed, a hole is punched on a paper disc.
2. The instrument rotates 180 degrees.
3. 45 seconds later a second punch is made on the paper disc.

B) Drop Multi-Shot Inclination Survey
a) dropped through the drill string
b) lands on a baffle plate
c) surveys on the way out of the hole with the drill string

C) Gyroscopic Survey
- a) Components
  1. compass
  2. electric rotor
  3. timing device
  4. camera section
- b) Operation
  1. The gyro unit is oriented to a known direction.
  2. The timing devise is set.
  3. The instrument is encased in a special protective housing.
  4. It is lowered to the survey point.
  5. The survey is recorded.
  6. The instrument is retrieved from the well.
  7. The film is unloaded and developed.
- c) Multi-shot gyros are run the same way.
- d) Gyros are very sensitive to handling.

k- Orientation Methods

1) General
- A) Deflection in the right direction can only be accomplished through the accurate use of orientation tools.
- B) At the surface, these problems are generally solved by the use of graphs and charts (ouija boards).

2) Surface Method
- A) A telescope is placed on the derrick.
- B) While going in the hole, alignment is accomplished through the use of a sight bar attached to the rig floor.
- C) This process is repeated, as needed, until the tool is on bottom.
- D) Disadvantages:
  - a) time consuming
  - b) inaccurate

3) Direct Method
- A) Advantages
  - a) fast
  - b) accurate
  - c) economical
- B) Muleshoe Method
  - a) Tools required
    1. non-magnetic drill collar
    2. orienting equipment
    3. single-shot instrument
  - b) Operation
    1. Line up the (*slot/key*) in the orienting (muleshoe) sub with the face of the tool.
    2. Make up the non-magnetic collar.
    3. Make up the single-shot instrument and place it in the string.
    4. Once on bottom, weight is gently applied to align the face of the tool.
       - A. The compass chart and pendulum are the only components that are not lined up at this point.
    5. Once the film is retrieved and developed, there is a record of the reference line of the deflecting tool in direct relation to the magnetic direction of the bore hole.
    6. A relationship can be established between the tool face drift and magnetic north.
    7. If realignment is necessary consider:
       - A. torque.
       - B. drag on the drill string downhole.
    8. Once the tool has been realigned, another survey must be conducted.

c) Disadvantages
   1. Cannot be used when circulation is required since full circulation is not possible.

C) Magnetic Method
   a) can be carried out when full circulation is required because it eliminates the orienting sub
   b) Components
      1. non-magnetic drill collar
         A. contains six small magnets
      2. orienting magnets
      3. special orienting instrument
         A. swinging pendulum
         B. regular compass
         C. needle-type compass that is locked into place by magnets
   c) Operation
      1. The assembly is spaced out (matched to the non-magnetic collar so that the magnetic position indicator lands opposite the orienting magnets).
      2. The drilling assembly is made up.
      3. The drill pipe is run to bottom.
      4. The instrument assembly is run inside the drill pipe.
      5. The data is recorded.
      6. Once the data is developed, it shows the orientation of the needle compass with respect to the regular compass.
         A. This information gives the relative position of the magnets and the direction of the hole.
         B. A special reader is used to calculate the direction in which the tool is facing.

4) Indirect Method
   A) based on the direction of the low side of the hole
      a) need to know the hole direction
      b) normally requires a 3 degree minimum inclination in order to function properly
   B) Method using *Mechanical* Orienting Tools
      a) Operation
         1. The orienting assembly is locked into place.
         2. It is run to the bottom of the hole.
         3. The string is worked up and down until the free rolling ball that is confined to a circular space within the tool seeks the low side of the hole.
         4. Once aligned, the ball will seat in a slot on the orienting stem.
         5. The tool closes.
            A. opens ports
            B. allows mud through
            C. lowers the pressure at the surface
   C) Method using *Survey* Orienting Tools
      a) Components
         1. sub
            A. magnets
            B. scribe lines
            C. protractor
         2. orientation tool
            A. timing device
            B. special compass
            C. swiveling magnetic disc
            D. plumb bob
      b) Operation
         1. The sub is made up.
         2. The assembly is lowered to bottom.
         3. The orientation tool is lowered to bottom through drill pipe on a wireline.

4. The north pole of the compass is frozen by the field created by the two south poles of the magnets in the sub.
   A. This registers the relative position of the tool face.
5. The plumb bob seeks the low side of the hole.
6. The tool's reference line is recorded with respect to the angle-indicator.
7. Through the use of a chart reader the direction of the tool can be determined.

5) Gyroscopic Single-Shot Orientation
   A) not affected by magnetic field
   B) Operation
      a) While at the surface the:
         1. gyro is oriented to a known axis.
         2. instrument is synchronized with a watch.
         3. unit is placed in a protective housing.
      b) It is run in the hole through drill pipe on a wireline.
      c) The shot is taken.
         1. The data is recorded and retrieved.
      d) The disc is developed and read on the spot.
      e) Computations can be plotted immediately.
   C) There is no need to orient the tool while going in the hole.

6) Directional Orientation Tool:
   A) allows the Operator to maintain proper orientation while drilling.
   B) continuously monitors the torque of the drill string.
   C) contains a sensing probe that is top-connected to the wireline.
   D) seats itself into the bent sub.
   E) signals are sent to the surface through the wireline.

I- **Survey Computations**

1) Before computations are made, magnetic north must be corrected to true north with the use of declination diagrams that are generic to the local area.
2) Course Plots
   A) Courses are plotted in the vertical plane as well as the horizontal plane.
   B) After each survey is made, a point is made on both of the plots.
3) Methods for Calculating the 3-Dimensional Location of the Hole
   A) Tangential Method:
      a) assumes that the hole will maintain the same drift and bearing in between each survey.
      b) Inaccuracies led to the development of other reliable methods.
   B) Average-Angle Method:
      a) assumes that the borehole is parallel to the average of the drift and bearing angles between two surveys.
      b) Calculations can be performed without the aid of calculators or computers.
   C) Radius-of-Curvature Method:
      a) assumes that the hole is a smooth arc between surveys.
      b) accurate but usually requires a calculator or computer.
   D) Minimum-Curvature Method:
      a) assumes a maximum radius of curvature between surveys.
      b) requires the use of computers or calculators.

m- Common Problems with Orientation Tools

1) Magnetic Forces
   A) counter by using non-magnetic elements in enough length to compensate
2) High Temperatures
   A) combat through the use of high temperature heat shields

n- Economics of Directional Drilling {55}

1) Generally speaking, penetration rates in directional wells are slower than rates in straight holes.

2) Comparison of Directional Holes to Straight Holes with Respect to Penetration Rates:

	Hard Rock Areas	**Medium to Soft Rock Areas**
% of time to be added for the initial deflection and build-up portion of the hole..............................	30% - 50%	25%
% of time to be added for correctly deviated hole..	20% - 25%	10% - 15%

This comparison is based on measured depth (i.e. - compared "foot for foot" of drilled hole).

3) Example of the use of the information from **2)**.
   A) The following information applies to a typical *vertical* well drilled in a medium to soft rock area:

Depth (TVD)	**Time (# of days)**
0,000' - 1,000'	1
1,000' - 2,000'	2
2,000' - 4,000'	4
	7 days total

   B) Estimate the number of days it would take to drill a *directional* hole where the:
      a) initial deflection point is 1,000' (TVD).
      b) drift angle is 25 degrees at a $2^1/_2$ degree angular increase per 100' of drilled hole.
      c) build-up portion of the hole would be between 1,000' and 2,000' of measured depth (1,000' and 1,964' TVD).

   C) From the chart in A), it will take @ 1 day to drill the first 1,000' of hole.

   D) From the chart in A), it will take @ 2 days to drill from 1,000' to 2,000'.
      a) Initial deflection and build-up is performed during this interval.
      b) Determine the additional time needed.
         1. From the chart in **2)**, it will take @ 25% more time.
            2 days + [0.25 x 2 days] = 2.5 days

   E) From the chart in A), it will take @ 4 days to drill from 2,000' to 4,000'.
      a) The desired angle of 25 degrees has been obtained and the hole is on a directional course.
      b) Determine the additional time needed to drill the deviated hole.
         1. From the chart in **2)**, it will take @ 15% more time.
            4 days + [0.15 x 4 days] = 4.6 days

F) A measured depth of 4,000' in this *directional* hole is actually only 3,780' at true vertical depth.
   a) To extend this comparison of penetration rates to the *vertically* drilled hole, the "extra" time required to drill the additional 220' of vertical depth will have to be accounted for.
      1. Given the two different depths and the hole angle, use trigonometry to calculate the amount of extra hole required.
   b) An extra 240' of *directional* hole must be drilled in order to obtain the additional 220' of vertical depth.
      1. 2,000' + 4 days = 240' + X days
      2. X = 0.5 days

      0.5 days + [0.15 x 0.5 days] = 0.6 days

G) In summary, to obtain 4,000' of true vertical depth would require:
   a) 4,240' of directional hole.
   b) 8.7 days.

      1 + 2.5 + 4.6 + 0.6 = 8.7 days

H) This example:
   a) calculates only the time spent drilling, tripping and running orientation tools.
   b) ignores any additional time delays caused by reaming, casing and cementing.

4) Cost Comparisons

A) In estimating the costs associated with directional drilling, there are three additional items that must be included in the costs.
   a) Cost of supervision
      1. usually charged by daily rates
   b) Cost of deflection and orientation tools
      1. usually charged by daily rates
   c) Cost of auxiliary equipment
      1. bits
      2. hole openers
      3. stabilizers
      4. orientation equipment
      5. instruments
      6. substitutes
      7. reamers
      8. non-magnetic drill collars

B) In estimating a multiple-well program, the sale cost of reusable equipment can be distributed over the multiple-well program providing for the actual life of the reusable equipment.
   a) The cost comparison between single and multiple programs becomes more complex as the number of wells increases due to the additional application of sale equipment that has worn out.
   b) Usually, the replaced sale equipment will be added to the applicable well and distributed to the succeeding wells or to the entire program.

C) The costs of a directional well will also be a function of the size of the target.
   a) The degree of difficulty of hitting the target will increase costs and will depend on the:
      1. size of the target.
      2. hostility level of the drilling environment.
      3. knowledge and experience level of the Supervisor and the Drilling Contractor.
      4. quality of the directional tools.

H- TRUE VERTICAL DRILLING

a- Tips

1) Use less bit weight than that which would cause the drill collars to buckle.
2) Use higher rotary speeds than usual.
3) Properly position the stabilizers.
4) Drill straight pilot holes, then ream them out.

b- Conventional Thoughts regarding Straight-Hole Drilling { 43 }

1) Application of the Pendulum Approach to Straight-Hole Drilling

A) This approach:

a) uses gravity to control the change in hole angle by proper placement of a stabilizer to give the:

1. maximum pendulum force.
2. maximum weight on bit.

b) is used mostly as a corrective measure to reduce angle when the maximum allowed deviation has been reached.

2) Application of the Packed-Hole Approach to Straight-Hole Drilling

A) Select a bottom-hole assembly (BHA) to be run above the bit with the necessary stiffness and wall contact tools to force the bit to drill a straight hole.

a) resulting gradual changes in hole angle produce a usable hole

B) Pertinent Design Parameters

a) regional crooked-hole tendencies

b) formation firmness

C) Before making final selections, seek help from Drillers who have experience in the area.

D) Some recommended BHAs, depending on the situation.

a) Mild Crooked-Hole Country

1. Soft formations

A. drill collars (DCs)
B. string stabilizer
C. 30' drill collar
D. stabilizer
E. bottom-hole stabilizer
F. bit

2. Medium hard formations

A. drill collars (DCs)
B. string stabilizer
C. 30' drill collar
D. vibration dampner
E. string stabilizer
F. large diameter short drill collar
G. 3-point reamer
H. bit

3. Hard formations that are abrasive

A. drill collars (DCs)
B. string stabilizer
C. 30' drill collar
D. vibration dampner
E. string stabilizer
F. large diameter short drill collar
G. 3- or 6-point reamer
H. bit

4. Hard formations that are not abrasive

A. drill collars (DCs)
B. string stabilizer
C. 30' drill collar
D. vibration dampner
E. string stabilizer
F. large diameter short drill collar
G. shop- or rig-reparable stabilizer or 6-point reamer
H. bit

b) Medium Crooked-Hole Country

1. Soft formations
   A. drill collars (DCs)
   B. string stabilizer
   C. 30' drill collar
   D. string stabilizer
   E. short drill collar
   F. string stabilizer
   G. bottom-hole stabilizer
   H. bit
2. Medium hard formations
   A. drill collars (DCs)
   B. non-rotating or rig-repairable stabilizer
   C. 30' drill collar
   D. vibration dampner
   E. shop- or rig-repairable stabilizer or 3-point reamer
   F. large diameter short drill collar
   G. string stabilizer
   H. shop- or rig-repairable stabilizer or 6-point reamer
   I. bit
3. Hard formations that are abrasive
   A. drill collars (DCs)
   B. non-rotating or rig-repairable stabilizer
   C. 30' drill collar
   D. vibration dampner
   E. shop- or rig-repairable stabilizer or 3-point reamer
   F. large diameter short drill collar
   G. string stabilizer
   H. 3- or 6-point reamer
   I. bit
4. Hard formations that are not abrasive
   A. drill collars (DCs)
   B. non-rotating or rig-repairable stabilizer
   C. 30' drill collar
   D. vibration dampner
   E. shop- or rig-repairable stabilizer or 3-point reamer
   F. large diameter short drill collar
   G. string stabilizer
   H. shop- or rig-repairable stabilizer or 6-point reamer
   I. bit

c) Severe Crooked-Hole Country

1. Soft formations
   A. drill collars (DCs)
   B. string stabilizer
   C. 30' drill collar
   D. string stabilizer
   E. large OD short drill collar
   F. tandem stabilizers
   G. string stabilizer
   H. bottom-hole stabilizer
2. Medium hard formations
   A. drill collars (DCs)
   B. non-rotating or rig-repairable stabilizer
   C. 30' drill collar
   D. vibration dampner
   E. shop- or rig-repairable stabilizer or 3-point reamer
   F. large diameter short drill collar
   G. tandem stabilizers
   H. string stabilizer
   I. shop- or rig-repairable stabilizer or 6-point reamer
   J. bit

3. Hard formations that are abrasive
   A. drill collars (DCs)
   B. non-rotating or rig-repairable stabilizer
   C. 30' drill collar
   D. vibration dampner
   E. shop- or rig-repairable stabilizer or 3-point reamer
   F. large diameter short drill collar
   G. tandem stabilizers
   H. string stabilizer
   I. 3- or 6-point reamer
   J. bit

4. Hard formations that are not abrasive
   A. drill collars (DCs)
   B. non-rotating or rig-repairable stabilizer
   C. 30' drill collar
   D. vibration dampner
   E. shop- or rig-repairable stabilizer or 3-point reamer
   F. large diameter short drill collar
   G. tandem stabilizers
   H. string stabilizer
   I. shop- or rig-repairable stabilizer or 6-point reamer
   J. bit

I- ADVANCES IN THE DRILLING INDUSTRY { 56 }

a- Top-Drive Drilling System:

1) can make up the drill string quicker and more safely.
2) can pivot, extend, retract and elevate pipe loads.
3) enables the rig to:
   A) get in and out of tight holes.
   B) avoid stuck pipe (can drill its way out).
      a) most significant advantage
4) significantly reduces drilling time.
5) requires special handling equipment attached to the drive unit.
   A) Complaints have been made that it is inefficient at pipe handling.
6) may require derrick alterations that represent 25% to 30% of the cost of the installed system.
7) can pay for itself in the long run.
8) very seldom found onshore.

b- Horizontal Drilling System:

1) allows penetration of formations that would not normally be penetrable with vertical wells.
2) permits drilling a wellbore above water contacts.
   A) limits the effects of water coning
   B) limits the intrusion of formation water
3) enhances oil recovery by allowing greater surface area for injecting steam, water, or carbon dioxide.
4) sets up the possibility of gravity drainage.
   A) Arguments can be made that the same productivity increase can be achieved through fracturing.
5) improves oil recovery efficiency.
6) theoretically realizes significant productivity gains in tight, low-permeability reservoirs by increasing the millidarcy-feet exposed to the wellbore.
   A) millidarcy - measurement of permeability
7) costs 20% to 30% more than conventional vertical wells.

8) Common Horizontal Systems

A) Types

a) Short Radius System

1. builds angles at rates of 3 degrees per foot

b) Medium Radius System

1. builds angles at rates of up to 20 degrees per 100 feet

c) Long Radius System

1. builds angles of up to 6 degrees per 100 feet

B) Planning a Horizontal Well

a) General planning considerations are the same as those normally required of all directional holes.

b) Inform/discuss with the Directional Company the:

1. length of horizontal reach.
2. expected rate of penetration.
3. formation description.
4. planned completion method.

c) Ask the Directional Company for a recommended:

1. radius of curvature.
2. drilling system.

C) Short Radius System

a) General

1. 300' to 750' reach depending on the formation
2. radius less than 300'
3. the true vertical interval that covers the beginning of the turn to the point at which the wellbore is horizontal

b) Applications

1. small leases
2. shallow reservoirs
3. recompletions
4. hard to hit "point" type targets

c) Advantages

1. Since the turn and reach is short:
   - A. this reduces the critical hole section where problems are likely to occur.
   - B. the vertical portion of the well is closer to pay.
     - a. facilitates pumping
   - C. the curve and horizontal part of hole remains in a single zone of interest.
     - a. reduces drilling problems and prevents gas coning
2. very accurate target acquisition
3. easy to re-enter existing wells with small drilling rigs

D) Medium Radius System

a) General

1. 1,500' to 3,000' reach depending on the formation
2. 300' to 700' radius

b) Applications

1. to solve water coning problems
2. fractured reservoirs
3. thin-bedded formations

c) Advantages

1. requires a short control path
   - A. leaves less hole below the dogleg
   - B. less keyseating when compared to long radius
2. less torque and drag
   - A. higher and more consistent build rates than a long radius
3. allows for selective completions
4. can be logged with conventional equipment
5. can use artificial lift

E) Long Radius System

a) General

1. 2,000' to 5,000' reach depending on the formation
2. radius greater than 700'

b) Applications

1. development drilling from a central location

c) Advantages

1. extremely long reaches can be achieved

d) Disadvantages

1. length of build section often requires several hole sizes and casing settings to get the well to total depth
2. a lot of hole has to be drilled before the well gets to the horizontal attitude

F) Tools Required for Each Type

a) Short Radius

1. short, articulated, positive-displacement steerable motor

b) Medium Radius

1. positive-displacement motor with special stabilizers, deflection subs, and a tilted drive sub
2. to build angle, a fixed-angle build motor or a steerable-angle build motor (not-rotated vs. rotated)
   A. When the fixed-angle build motor is rotated, it drills straight ahead.
   B. In some cases a straight tangent can be drilled within the curve to assure that the well reaches horizontal at the specified target depth.

c) Long Radius

1. custom diamond bit
2. steerable motor
   A. low speed
   B. high torque
   C. bent sub
3. measurement while drilling (MWD) tool

G) Horizontal Candidates

a) thin zones
b) naturally fractured zones
c) low permeability zones
d) formations with a gas cap
e) formations with bottom water
f) Production rates from some partially depleted zones are improved by horizontal drilling due to gravity assisted drainage.

H) Definitions

Setback Distance - the distance away from the target needed in order to enter the target zone horizontally.

Vertical Section - the portion of the hole above the planned deviation.

Kick-off Point - the point in the vertical section where the building assembly is installed and the wellbore is deviated from vertical.

Build Section - the section of the hole where the angle building assembly is used to achieve the desired radius of curvature below the kick-off point.

Tangent Section - that portion of the hole where the bit path is adjusted/held such that it will encounter the target formation at the desired approach angle.

Approach Phase - the very critical part of the horizontal operation where the angle is adjusted to intersect the target reservoir at the correct point with the correct angle.

Horizontal Section - that lateral section of the hole inside the target formation.

c- **Polycrystalline Diamond Compact (PDC) Bits**

1) also known as ugly bits or strata bits
2) Applications
   A) thick homogeneous formations
3) Compared to conventional bits, they:
   A) last longer in shales.
   B) drill faster in shales.
   C) have better directional control.
   D) work faster than mill tooth bits through soft formations.
   E) have a longer life.
4) Considerations when Using these Bits
   A) Use adequate hydraulics to:
      a) keep the bit cool.
      b) remove the cuttings at higher rates of penetration.
   B) Use adequate solids separation equipment to keep up with the high rates of penetration (ROP).
   C) Run shock absorbers in those formations that cause the drill string to bounce.
   D) In pendulum assemblies, running a stabilizer too close to the bit can create problems.
   E) Do not run these bits in zones that contain known chert nodules.
5) Avoid hole deviation problems by using:
   A) a pendulum hook-up.
   B) high rotary speeds with reduced weights.

d- **Thermally Stable Diamond (TSP) Bits:**

1) designed for drilling in harder, abrasive formations.
2) feature diamond bearings in place of standard bearings.
3) could result in as high as twice the penetration rates made by conventional bits.

e- **High-Speed Downhole Motors:**

1) operate more efficiently at higher pressures.
2) increase drilling speed.
3) solve torque problems in high-angle holes.

f- **Measurement while Drilling (MWD)** { 57 }

1) General
   A) New tools can measure:
      a) neutron porosity.
      b) density porosity.
      c) resistivity.
   B) MWD gives real time information prior to filtrate invasion.
   C) Costs of MWD are dropping.

2) Communications with the Surface
   A) Data Transmission via Mud-Pulse Telemetry
      a) most widely accepted MWD tools
      b) Data from downhole sensors are digitally encoded and transmitted to the surface via positive or negative pressure waves in the mud stream.
         1. These waves, which move at approximately 4,000 feet per second, are decoded by a computer at the surface.
      c) The Operator communicates with the tool by cycling the mud pumps, momentarily shutting off part of the mud stream or stopping rotation.
         1. When actuated, a valve in the pulser unit releases a small volume of mud into the annulus that creates a pulse.
         2. A pressure transducer attached to the standpipe detects these pulses.

3. The transducer signal is relayed to the on-site computer.
   A. filters extraneous and unwanted signals
   B. decodes the data

d) Formation resistivity and gamma-ray make up the standard format although some tools measure mud resistivity, temperature and other formation-related parameters.
   1. Resistivity helps to:
      A. identify formation markers.
      B. indicate the presence of hydrocarbons.
      C. alert the Driller about abnormal pressures.
   2. Most sensors employ a short, normal electrode.
   3. Gamma-ray sensors measure the radiation of the formations by means of a Geiger-Mueller detector.
      A. Since most lithologies produce a characteristic radiation value, a gamma-ray detector can indicate when the target formation is penetrated.

B) Data Transmission via Continuous-Wave Telemetry.

a) This method involves a rotating valve in the mud stream with a fixed frequency.

b) The rotating valve sends information encoded on a pressure wave in digital form to the surface.

C) Directional sensors are very often incorporated in the MWD system to measure:

a) inclination.

b) azimuth.

c) toolface orientation.

D) Electrical Power

a) Power for the downhole assembly is provided by:
   1. battery pack.
      A. has no minimum or maximum mud flow requirements
      B. has limits to power in certain situations
   2. turbine generators.
      A. more power
      B. operates as long as there is mud flow

E) Wellsite Operations

a) Sensor and transducer placement
   1. Sensors are placed in non-magnetic drill collars.
   2. Pressure transducers are placed in/on:
      A. standpipe.
      B. mud pumps.
      C. kelly/hose assembly.
      D. hook.

b) Precautions
   1. Drilling mud should have the properties that will not interfere with the operations of the valves.
   2. Iron-based additives affect magnetic sensors.
   3. Low pH (acidic) muds:
      A. deteriorate the rubber components.
      B. bond on tungsten carbide parts.
   4. Lost circulation material clogs up:
      A. turbine valves.
      B. screens.
   5. Pump pressure and flow rates should be maintained within specific limits so that interference with downhole sensors is avoided.
   6. When surveys are conducted, the drill string should remain motionless.

g- Drilling Fluids

1) Low toxicity oil-base muds
   A) reduce clay swelling, crumbling and sloughing
2) High molecular weight water-base muds
3) Potassium chloride (KCl) polymers
   A) for shales and other reactive formations
4) The replacement of barite with hematite
   A) higher specific gravity
   B) better quality control
   C) more abrasive on equipment
   D) very expensive

h- Multi-Conduit Drill Pipe System:

1) consists of a number of small pipes attached around the perimeter of one larger pipe.
   A) allows high-pressure jet-assisted drilling
   B) maintains downhole stability
   C) reduces washouts
2) cuts a hole up to 10 times faster in lab tests.
3) increases pressures downhole.
4) has better solids removal.

8 - FISHING

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A- GENERAL {58}

a- Economics {59}

1) Planning
   A) It is critical to carefully design and inspect all equipment before a well is started.
      a) Consider how the specific drilling conditions will affect the:
         1. drill string.
         2. bottom-hole assembly.
      b) Check all threads.
         1. rental equipment
         2. fishing tools
         3. directional tools
   B) It is less expensive to inspect than to fish.
2) Possible Problems
   A) The drill string will have a greater tendency to stick if the mud has poor properties.
   B) Reduce the possibility of keyseats.
      a) Add a stabilizer or a keyseat wiper at the top of drill collars.
         1. guides the bottom-hole assembly around the keyseat
3) Preventive Measures
   A) Make frequent wiper trips.
   B) Control the rates of penetration.
   C) Pump viscous sweeps before trips.
4) When deciding whether or not to fish, consider:
   A) past performance.
   B) availability of knowledgeable Fishing Operators.
   C) area of drilling activity.
   D) hole and casing size.
   E) hole conditions.
5) After the Drill String is Stuck
   A) *Time is of the essence.*
      a) The longer it takes to spot fluids, the harder it is to free the fish.
      b) Spot fluids in less than 8 hours.
      c) Allow 24 to 36 hours for the fluids to free the fish.
      d) If a fish is stuck for more than 96 hours, it usually cannot be freed with a spotting fluid.
   B) While the spotting fluid is working:
      a) plan the fishing job.
      b) dispatch the tools and a wireline unit to the location.
   C) Run a free point and back-off 1 or 2 joints above the stuck point.
   D) If the decision is made to sidetrack, dispatch equipment to the location.
      a) cement
      b) tools

b- Definitions

Back-off - disconnecting a joint downhole by either unscrewing it or by explosive charge.

Filter Cake - see Chapter 12 - Drilling Mud

Fish - drill pipe, or anything in the hole that needs to come out.

Fishing - the act of attempting to mechanically retrieve something out of the hole.

Free Point - that point in a stuck string above which the pipe is free and below which the pipe is stuck. Sometimes used as an adjective: "run a free point". In this case, it is an operation where a tool that measures mechanical stress is lowered in the hole. It locates the free point because stuck pipe will not react to mechanical stress.

GIH - go(ing) in the hole.

Impression Block - a cylinder-shaped tool made of a thick, very malleable material such as lead. It is screwed into the end of the drill pipe, run into the hole, and pushed against the top of the fish. The drill pipe is pulled out of the hole bringing with it a reverse impression of the fish.

Jar - a tool engineered to hammer in an upward fashion.

Junk - cones, teeth, bearings, tool parts, broken slips, bits of wireline, hand tools, debris from twisted-off pipe, cuttings (small, non-drillable metal items).

Knuckle Joint - a joint of pipe that contains a portion that is designed to bend. When activated it forces the fishing tool out to the side of the hole.

Making Hole - drilling with penetration.

Mill - a tool that is designed to shave metal.

Overshot - a tool that "swallows" the top of the fish and grabs with an internal mechanism.

POOH - pull(ing) out of the hole.

Settle Out - over a long period of time, tiny particles in the annular fluid coagulate, fall to the bottom and rest on top of the packer.

Spot - to accurately place a volume of fluid at a particular depth.

Strap - to measure, with a metal tape, the drill pipe as it comes out of the hole in order to get an accurate depth of the well.

String Shot - primacord wrapped on and around itself, all of which is wrapped around a metal bar with a firing head.

T/fish - top of the fish.

Twist-off - when a drill pipe separates by breaking (mechanical failure), either at the joint or in the tube of the drill pipe, while drilling.

Wall Hook - a tool that reaches out to pull the fish away from the wall of the hole.

Wash Pipe - a pipe with a larger ID than that of the fish's OD.

Washover - the lowering of a string of wash pipe over the fish in order to prepare the fish for retrieval.

c- Actions when Twist-off is Suspected

1) Stop drilling but continue rotation and circulation.
    - A) With a piece of chalk, mark a line where the kelly intersects the kelly bushing.
        - a) All future measurements are taken from that chalk mark.
    - B) Carefully measure the distance from the chalk mark down to the end of the kelly.
2) Spot a viscous pill on bottom.
3) Make sure that the drilling fluid is circulated away from the top of the fish.
4) Be sure to keep the drill pipe moving.
    - A) Accomplishing 3) and 4) will help to keep from washing out the soft formation near the top of the fish.
        - a) helps to ensure an easy catch of the top of the fish
5) Quickly strap out of the hole.
    - A) Double check the pipe tally to clear it of any math errors.
        - a) depth control
    - B) Make sure that the kelly is included in the pipe tally measurements.
    - C) Order various sizes of fishing tools sent to the location.
        - a) Sizes are based on:
            1. the original size of the drill pipe.
            2. the possible sizes to which it is pinched or stretched.

6) If possible, make the following determinations.
   A) Is the fish stuck in the hole or is it resting freely?
   B) Is it in casing or open hole?
   C) What shape is the fish in?
   D) At what depth is the top of the fish?
7) When the twisted-off joint comes out of the hole, inspect it.
   A) It gives a reverse image of what the top of the fish looks like.
   B) Try to determine why the failure occurred.
   C) Decide whether or not a change in drilling operations is in order so that future failures can be prevented.
8) If there is a doubt as to what shape the top of the fish is in, run an impression block. [**c-, 5)**]
9) If the top of the fish is badly damaged, run a skirted mill to:
   A) dress off the top of the fish.
   B) keep it from sidetracking the hole.
10) If the fish is drill collars, their OD is usually just a fraction of an inch less than the hole size.
   A) Sometimes a tapered tap is used to sting into (get inside) the fish.
      a) Always run a tap with a safety joint and jar.
      b) After the tap enters the fish it is sometimes hard to get the tap back out again.
         1. Sometimes other fishing tools need to be picked up.
   B) Washover operations are usually successful in drill collar recovery.

d- Considerations for the Use of Fishing Tools

1) Overshots
   A) If the OD of the fish (drill pipe) is near the maximum catch size of the overshot, use a spiral grapple, a spiral grapple control, and a plain-type packer configuration to grasp the top of the fish.
   B) If the OD of the fish is well below the maximum catch size of the overshot (usually $^1/_2$ inch), use a basket grapple and a plain control packer configuration.
   C) If the top of the fish (**t/fish**) is well below the maximum catch size of the overshot (usually $^1/_2$ inch) and the t/fish is burred, use a basket grapple and a mill-toothed control packer configuration, or mill control grapple.
   D) Be sure to use a hydraulic jar in the fishing string between the overshot and the drill collars.
      a) You can also run a jar accelerator between the collars and the drill pipe to decrease the shock to the drill pipe and derrick floor, and increase the shock to the fish.
      b) Otherwise, oil jars or bumper jars would be recommended.
   E) Measure the fishing tool combination with extreme care.
      a) Accurate knowledge of the distance the fish must travel to be firmly caught once inside the overshot is critical.
      b) Know how many joints of drill pipe and drill collars it takes to get to the top of the fish prior to starting into the hole.
   F) Run the overshot to within a few feet of the top of the fish.
      a) Circulate to clean the overshot and the top of the fish.
   G) Lower the overshot extremely slowly until the top of the fish is tagged (touched) then pick up the drill pipe and mark the kelly.
   H) Lower the overshot while rotating (without circulating) until the mark on the kelly is reached.
      a) Lower the kelly the distance that was measured from the bottom of the overshot to the inside top of the overshot.
      b) A decrease on the weight indicator should be seen.
   I) Release all torque in the string.
      a) Hammer the overshot over the fish:
         1. once fairly easy.
         2. once rather deliberately.
   J) Pick up the fish and (without rotation) circulate the hole clean.

K) When pulling out of the hole (**POOH**) with the fish, be careful not to rotate the fish while breaking out the connection (separating the drill pipe sections).
  a) Right-hand rotation will back the fish out of the overshot.

L) To release the fish when at the surface:
  a) bump down against the rotary slips.
  b) simultaneously:
    1. rotate the fishing string to the right.
    2. raise the fishing string.

M) If steps F) through K) are done without getting the fish, one of the following things has happened.
  a) pipe measurements are wrong
  b) overshot is too small
  c) grapples are too big
  d) t/fish is being bypassed
  e) t/fish is laying over in a washout
  f) t/fish is behind some obstruction
  g) t/fish is so badly damaged that the grapples cannot grab it

N) Carefully ensure that your selection of fishing tools have large enough IDs to allow a free point tool and a string shot.

O) When tools are ordered, be sure to include cross-over subs which have the same threads as the drill pipe if they are different from the threads on the fishing tool.

P) Washouts
  a) If the top of the fish is leaning over into a washout:
    1. for small hole enlargement use a cut lip guide for the overshot.
    2. for large hole enlargement use a wall hook.
    3. for very large washouts use a knuckle joint and a wall hook.

Q) Other Considerations {43}
  a) Always make a detailed drawing of the:
    1. fish.
    2. work string.
  b) Study the hole caliper.
    1. If not available, lag times are useful in estimating hole size.
  c) Formulate a plan of action.
    1. Devise several alternate plans.
      A. Explain why you recommend each plan.
    2. If the first plan does not work:
      A. update the plan.
      B. note why you think it failed.
  d) Before running fishing tools into the hole, observe and note all markings.
    1. If the tools fail, make notes as to the new markings.
  e) When going in the hole with tools:
    1. go in the hole slowly.
    2. monitor:
      A. strokes.
      B. pressure.
      C. torque.
      D. string weight.
    3. This will help remove guesswork as to whether or not the fish has been tagged.
      A. At least two of the parameters listed in 2. will change when the fishing tools are over the top of the fish.
  f) Before calling the office:
    1. analyze all of the facts.
    2. draft a first and second recommendation. (e.g.)
    3. have additional recommendations prepared as to what to do if the first two recommendations are tried and fail. (e.g.)
      A. Using an overshot and jars, work on a stuck fish for two hours.

B. If no progress is made, spot an oil-base lubricant and work the fish for 24 hours.
   a. Order enough to cover all collars in the hole plus 24 extra barrels.
   b. Make sure that the weight of the lubricant and the weight of the drilling fluid are close, otherwise the lubricant will u-tube (migrate and take the path of least resistance).
      1] Trying to spot it will be difficult.
   c. Spot the lubricant using a pump truck, leaving 24 barrels in the drill pipe and the top of the lubricant in the annulus above the drill collars.
   d. Work the fish every 15 minutes for at least an hour.
   e. Pump one barrel of lubricant through the bit and work for an hour.
   f. Repeat c. and d. for 24 hours.

C. If no progress is made, run a free point and back-off at the first collar above the free point.
   a. Go in the hole with jars and tie back (screw the pipe back together) into the fish.
   b. Repeat A. and B.

D. If no progress is made, begin washover operations.

4. Estimate the cost to give up, skid the rig and start a new well.
   A. Keep this number handy so that it can be referred to from time to time as a planning figure.
5. Make arrangements to have the weight indicator and pump gauges checked and re-calibrated if required.

2) Mills
   A) It is advisable to run a junk basket on top of a mill.
   B) When milling the top of the fish to dress it off, rotate the pipe slowly while using a high volume circulation.

3) Magnets
   A) If a magnet is run:
      a) be sure the tool has a large enough skirt to keep the junk from being knocked off while pulling out of the hole.
         1. A jet basket can be used for the same purpose.
      b) consider running it off of a wireline.
         1. saves time

4) Wall Hooks
   A) Using a Wall Hook without a Knuckle Joint
      a) Run the wall hook in the hole made up on the overshot.
      b) Be sure to accurately measure the distance from the bottom to the top of the wall hook opening, and from the wall hook opening to the stop inside the overshot.
      c) Repeat steps **c-, 1)**, F) and G) above.
      d) Lower the string with rotation until the t/fish is tagged again.
         1. Stop the downward movement but continue rotation.
      e) When the string torques up, the fish is in a bind.
      f) Lock the rotary table and raise the fishing string until all of the torque has been released.
         1. This shows that the wall hook:
            A. has been raised far enough for the t/fish to slip into the wall hook opening.
            B. is centered under the overshot.
      g) Lower the string the distance from the top of the wall hook opening to the stop inside the overshot to grasp the fish.
      h) If weight decreases, the fish has probably been engaged.
         1. Repeat **c-, 1)**, I), J) and K) above.

B) Using a Wall Hook with a Knuckle Joint
- a) Make it up from the bottom to the top.
  1. wall hook
  2. overshot
  3. knuckle joint
  4. fishing string
- b) Check the knuckle joint positioning to ensure that it forces the opening of the wall hook up against the wall of the hole.
  1. The pivot point may require the addition of spacer subs in order to make length adjustments.
- c) Run the tool to the t/fish and drop a plug (metal or plastic) to activate the piston.
  1. bends the knuckle joint
- d) Rotate slowly without lowering the string.
- e) Lower the tool a few feet and rotate again.
  1. Repeat until torque can be observed.
     A. The top of the fish enters the overshot.
- f) Once the fish is grabbed, the plug can be retrieved by wireline overshot.
- g) Pull the fish as in steps **c-**, **1)**, J) and K) above.

5) Impression Blocks
- A) If an impression block is run, be sure to have a sub above it to circulate through.
- B) Running impression blocks in wells with liners is tricky.
  - a) Were the marks made by the fish or the liner hanger?

e- Washover Operations

1) A typical washover string, top to bottom:
   - A) drill pipe
   - B) jar accelerator
   - C) drill collars
   - D) jars
   - E) washover back-off connector tool
     - a) allows the wash pipe to be rotated independent of the fish
     - b) allows release and recovery of the stuck fishing string, back-off tool and washed-over fish from the hole
   - F) several joints of wash pipe (not to exceed 500 feet)
   - G) rotary shoe
2) During washover:
   - A) run the string to within 10 feet of the top of the fish.
   - B) circulate.
   - C) lower the string slowly over the fish.
3) Once it is obvious that the washover pipe will go over the fish, begin rotation and washover at 30 - 50 RPM.
   - A) Be careful of torque.
   - B) If excessive, the wash pipe may have to be stoodback (shortened).
4) While washing-over, when you no longer get penetration, your washover back-off connector tool has probably either:
   - A) landed on the fish.
   - B) the shoe is worn out.
   - C) If you cannot pull the fish, repeat steps 2) and 3) until you recover the fish by stripping (pulling) it out of the hole.
5) If the bit is too large to fit through the wash pipe, you have to "double strip" (pull two pipe strings at the same time) out of the hole.
   - A) takes about 4.5 hours rig time to break out 500 feet of wash pipe

f- Free Point and Back-off

1) If the string of stuck pipe cannot be picked up after jarring (hammering) on it:
   - A) run a free point or estimate using the stretch method.
     - a) Get the exact depth of the 100% stuck point.
   - B) crank (apply) right-hand torque until you get 8 rounds (turns).
   - C) release the pipe and it will turn itself back around 6 or 7 times.
   - D) run a back-off string shot (wad of explosive).
   - E) put left-hand torque on the whole string.
     - a) minimum 6 turns, maximum 8 turns
   - F) jump the collars (separate the collar joints by explosive) 2 joints above the stuck point.
     - a) After shooting, do more left-hand rotation.

g- Costs

1) Estimate the Daily Cost of the Fishing Job
   - A) Average daily operating costs
   - B) Fishing tools
   - C) Operator (fishing tool hand)
   - D) Damage to the recovered fish
2) Fishing Costs
   - A) Daily total
   - B) Running total
3) Economic Limit
   - A) approximately 50% of the cost of sidetracking a new hole

B- DIFFERENTIAL STICKING OF DRILL PIPE

a- Discussion

1) The weight distribution of the drill string is such that the drill collars will always lie against the low side of the hole.
   - A) The depth that the collars penetrate into the filter cake on the wall of the hole depends primarily on the deviation of the hole.
2) While the pipe is rotated:
   - A) it is lubricated by a film of mud.
   - B) the pressure on all sides of the pipe is equal.
3) When rotation is stopped:
   - A) the portion of the pipe in contact with the filter cake is isolated from the mud column.
   - B) the differential pressure between the two sides of the pipe causes drag when an attempt is made to pull the pipe.
4) Differential sticking normally occurs when either:
   - A) circulation is stopped.
   - B) rotation is temporarily suspended (i.e. - making a connection).
5) The pipe is stuck if drag exceeds:
   - A) the rig's pulling power.
   - B) the tensional strength of the drill pipe.
6) To prevent differential sticking:
   - A) drill as straight a hole as is possible.
     - a) Long drill collar sections and oversized (packed-hole) collars increase the contact area.
   - B) minimize the contact area by suitable drill string design.
     - a) non-circular, fluted or spiral drill collars
     - b) drill collars and drill pipe stabilizers
   - C) keep mud weight as low as possible.
     - a) minimum mud densities
     - b) low cake thickness
     - c) low cake permeability
     - d) low solids

D) lower the friction coefficient by:
   a) using oil-base muds rather than water-base muds.
   b) the emulsification of oil in water-base muds.
   c) the addition of oil-wetting agents.
   d) lowering the barite content of all muds.

C- DIAGNOSIS OF STUCK PIPE {60}

a- Circulating when Sticking Occurs

1) Pipe Moving Up

A) Possible causes:

a) Keyseating
1. Has hole deviation been a problem in the past?
2. Are large diameter tools in the drill string?
3. Will the pipe rotate?
4. Does torque decrease when slacking off?
5. Does the pump pressure change when working the pipe?
6. Yes to 1., 3., and 4. indicates keyseat.
7. Yes to 2. and no to 5. further support this.

b) Undergauge Hole
1. Were bit or stabilizers undergauge after the last trip?
2. Are large diameter tools in the drill string?
3. Will the pipe rotate?
4. Does the pipe drop at all when slacking off?
5. Did the pump pressure increase at all at the time of sticking?
6. Yes to 1., 2., 3., and 5. indicates sticking in an undergauge hole.
7. No to 4. is further support.

c) Solid Particles
1. Has the drilling mud overbalanced the formation pressure?
2. Is there any previous evidence of shale caving?
3. Will the pipe rotate?
4. Did the pump pressure increase at the time of sticking?
5. Yes to 1., 2., 3., and 4. suggests sticking from solids.

2) Pipe Moving Down

A) Possible causes:

a) Solid Particles
1. Has the drilling mud overbalanced the formation pressure?
2. Is there any previous evidence of shale caving?
3. Will the pipe rotate?
4. Did the pump pressure increase at the time of sticking?
5. Yes to 1., 2., 3., and 4. suggests sticking from solids.

3) Pipe Not Moving

A) Possible causes:

a) Solid Particles
1. Has the drilling mud overbalanced the formation pressure?
2. Is there any previous evidence of shale caving?
3. Will the pipe rotate?
4. Did the pump pressure increase at the time of sticking?
5. Yes to 1., 2., 3., and 4. suggests sticking from solids.

b) Differential Pressure
1. Will the pipe rotate?
2. Does the pipe drop at all when slacking off?
3. No to 1. and 2. indicates a differential stick.

b- Not Circulating when Sticking Occurs

1) Pipe Moving Up

A) Possible causes:

a) Keyseating

1. Has hole deviation been a problem in the past?
2. Are large diameter tools in the drill string?
3. Will the pipe rotate?
4. Does torque decrease when slacking off?
5. Will the mud circulate?
6. Does the pump pressure change when working the pipe?
7. Yes to 1., 3., 4., and 5. indicates a keyseat.
8. Yes to 2. and no to 6. are supporting evidence.

b) Undergauge Hole

1. Were bit or stabilizers undergauge after the last trip?
2. Will the pipe rotate?
3. Will the mud circulate?
4. With pipe moving up (with high torque), yes to 2. and no to 3. indicates sticking in an undergauge hole.
5. Circulation may be established by slacking off.

c) Solid Particles

1. Has the drilling mud overbalanced the formation pressure?
2. Is there any previous evidence of tools balling?
3. Is there any previous evidence of shale caving?
4. Will the pipe rotate?
5. Will the mud circulate?
6. Do torque and pump pressures drop when working the pipe?
7. Pipe stuck by solids neither rotates nor circulates, at first.
   A. Both rotation and circulation are more likely if the pipe moves a little bit in the direction opposite to which it was moving when it stuck.
8. Yes to 6. along with freeing of the pipe means stuck by solids.
9. Yes to 2. indicates stuck by solids.
10. No to 1., and yes to 3. and 6. indicates stuck by solids.

2) Pipe Moving Down

A) Possible causes:

a) Undergauge Hole

1. Were bit or stabilizers undergauge after the last trip?
2. Will the pipe rotate?
3. Will the mud circulate?
4. With pipe moving down (with high torque), yes to 2. and no to 3. indicates sticking in an undergauge hole.
5. Circulation may be established by slacking off.

b) Solid Particles

1. Has the drilling mud overbalanced the formation pressure?
2. Is there any previous evidence of tools balling?
3. Is there any previous evidence of shale caving?
4. Will the pipe rotate?
5. Will the mud circulate?
6. Do torque and pump pressure drop when working the pipe?
7. Pipe stuck by solids neither rotates nor circulates, at first.
   A. Both rotation and circulation are more likely if the pipe moves a little bit in the direction opposite to which it was moving when it stuck.
8. Yes to 6. along with freeing of the pipe means stuck by solids.
9. Yes to 2. indicates stuck by solids.
10. No to 1., and yes to 3. and 6. indicates stuck by solids.

3) Pipe Not Moving

A) Possible causes:

a) Solid Particles

1. Has the drilling mud overbalanced the formation pressure?
2. Is there any previous evidence of tools balling?
3. Is there any previous evidence of shale caving?
4. Will the pipe rotate?
5. Will the mud circulate?
6. Do torque and pump pressures drop when working the pipe?
7. Pipe stuck by solids neither rotates nor circulates, at first.
   A. Both rotation and circulation are more likely if the pipe moves a little bit in the direction opposite to which it was moving when it stuck.
8. Yes to 6. along with freeing of the pipe means stuck by solids.
9. Yes to 2. indicates stuck by solids.
10. No to 1., and yes to 3. and 6. indicates stuck by solids.

b) Differential Pressure

1. Will the pipe rotate?
2. Will the mud circulate?
3. No to 1. and yes to 2. suggest stuck by differential pressure.
4. Previous history of drill collars threatening to stick opposite zones of permeability is more evidence.

c) Undergauge Hole

1. Are large diameter tools in the hole?
2. Will the pipe rotate?
3. Will the mud circulate?
4. Does the pipe drop at all when slacking off?
5. Sticking by this mechanism is likely only if the pipe has not been moved for long periods of time.
6. No to 2., 3., and 4. may all be supporting evidence.

D- SOURCES OF STICKING MECHANISMS { 60 }

a- Keyseat

1) hole deviation
   A) Ledges in a deviated hole are vulnerable to keyseat development.
   B) The longer it takes to make the hole, the more likely sticking by keyseating becomes.

b- Undergauge Hole

1) filter cake
2) shale swelling
3) shale extruding
4) shale hydration
5) undergauge bit

c- Solid Particles

1) shale caving
2) junk
3) boulder movement
   A) most likely to occur at shallow depths
4) inadequate hole cleaning
5) disturbance of cuttings stacked on the lower surface of a washout

d- Differential Pressure

1) pipe laying motionless against the wall of the hole
   A) The larger the pipe area lying against the wall, the more tightly the pipe is stuck.
2) filter cake accumulation

E- CORRECTIVE MEASURES { 60 }

a- When Sticking Occurs while Circulating

1) To Free the Pipe

A) Keyseat

a) Calculate the free point from pull and stretch figures for proper placement of fluids. [G-, b-]
b) Try spotting fluids at least twice.
c) Washover.

B) Undergauge hole

a) Calculate the free point from pull and stretch figures for proper placement of fluids.
b) Try spotting fluids at least twice.
c) Washover.

C) Solid Particles

a) Calculate the free point from pull and stretch figures for proper placement of fluids.
b) Try spotting fluids at least twice.
c) Washover.

D) Differential Pressure

a) Calculate the free point from pull and stretch figures for proper placement of fluids.
b) Try spotting fluids at least twice.
c) If possible, lower the mud weight.
d) If applicable, set a drill stem test (DST) tool and release pressure.
e) Put right-hand torque on the pipe, slack off and let stand for awhile.
f) Washover.

2) To Prevent Recurrence

A) Keyseat

a) Wipe out the keyseat.
b) Add a torque reducer to the drilling fluid.

B) Undergauge Hole

a) Determine if the undergauge hole is opposite carbonate, sand or shale.
   1. If opposite carbonate or sand, lower the mud filtration rate.
   2. If opposite shale, check and adjust as necessary:
      A. mud weight
      B. mud chemistry
      C. mud filtration rate
b) Modify bit selection procedures to include increased gauge protection.
   1. ensures that the bit continues to drill a uniform hole size

C) Solid Particles

a) Junk
   1. Remove or try to squeeze into the wall.
b) Boulders
   1. Try to break up using mechanical means.
c) Shale caving
   1. Check and adjust as necessary:
      A. mud weight
      B. mud chemistry
      C. rheology
      D. mud filtration rate

D) Differential Pressure

a) Move the pipe frequently.
b) If possible, reduce the mud weight.
c) Add a torque reducer or asphalt to the mud.
d) Run smaller or grooved drill collars.

b- When Sticking Occurs while Not Circulating

1) To Free the Pipe
   - A) Keyseat
     - a) Calculate the free point from pull and stretch figures for proper placement of fluids. [G-, b-]
     - b) Try spotting fluids at least twice.
     - c) Washover.
   - B) Undergauge Hole
     - a) Calculate the free point from pull and stretch figures for proper placement of fluids.
     - b) Try spotting fluids at least twice.
     - c) Washover.
   - C) Solid Particles
     - a) Calculate the free point from pull and stretch figures for proper placement of fluids.
     - b) Try spotting fluids at least twice.
     - c) Washover.
   - D) Differential Pressure
     - a) Put right-hand torque on the pipe, slack off and let stand for awhile.
     - b) Calculate the free point from pull and stretch figures for proper placement of fluids.
     - c) Try spotting fluids at least twice.
     - d) If possible, lower the mud weight.
     - e) If applicable, set a DST tool and release pressure.
     - f) Washover.

2) To Prevent Recurrence
   - A) Keyseat
     - a) Wipe out the keyseat.
     - b) Add a torque reducer to the drilling fluid.
   - B) Undergauge Hole
     - a) Determine if the undergauge hole is opposite carbonate, sand or shale.
       1. If opposite carbonate or sand, lower the mud filtration rate.
       2. If opposite shale, check and adjust as necessary:
          - A. mud weight
          - B. mud chemistry
          - C. mud filtration rate
   - C) Solid Particles
     - a) Calculate the size of the largest particle of shale that would have been carried out of the hole under the conditions that existed at the time of sticking.
     - b) Did this particle come from the bit or from caving?
       1. Bit
          - A. Calculate and specify the rheology required to provide adequate reduction in slip velocity.
       2. Caving
          - A. Check and adjust as necessary:
            - a. mud weight
            - b. mud chemistry
            - c. mud filtration rate
          - B. If economics rule out changes in the drilling fluid, try to get the hole made with thick mud.
     - c) Calculate and specify the conditions required to maintain laminar flow in the annulus.
   - D) Differential Pressure
     - a) Move the pipe frequently.
     - b) If possible, reduce the mud weight.
     - c) Add a torque reducer or asphalt to the mud.
     - d) Run smaller or grooved drill collars.

F- FISHING FOR A MUD-STUCK PACKER

a- General

1) If sticking because of "settling out" on top of the packer, it:
   A) will generally be stuck for five joints.
   B) will be stuck for up to five joints above the liner top and free in between if the well has a liner and packer.
   C) can be stuck over much larger intervals.
2) Consider recalibrating the weight indicator before getting too far into the fishing job.
3) It is sometimes easy to be mislead by the stretching of the tubing into thinking that the tubing is free.
   A) After hard pulls on the tubing, all of the joints in the string should be retightened while it is being run into the hole again.

b- Annular Fluid is a Polymer

1) If the packer fluid is a polymer or gelled fluid, or the packer is stuck due to sand on top of the packer from a set of perforations in the casing above the packer, work the tubing thoroughly for about 4 hours.
   A) If it is a polymer, viscosity should decrease once the fluid changes from a gelled to a liquid state.
2) If not making progress, run a free point by the tubing stretch method.
   A) See **G-**, **b-** below.
   B) If the free point is within 2,000 feet of the packer, go to 3).
   C) If not, go to 8).
3) Perforate three holes as deep as possible on the first full tubing joint above the packer.
   A) Try to circulate.
   B) If you cannot circulate, repeat step 3) about 300 feet up the hole.
   C) Repeat the process until circulation is established.
4) Once circulation is established, drop frac balls to isolate the next deeper perforations.
   A) Repeat the frac ball procedure until circulation is established through all of the perforated holes above the packer.
   B) Remember that the frac balls could interfere with:
      a) the operation of downhole tools.
      b) subsequent operations in the well.
5) Once fluid can circulate easily above the packer, attempt to retrieve it.
6) If still stuck, back-off with a string shot above the packer.
7) Go in the hole with an overshot and jars.
   A) Grab the packer and jar it lose.
8) Shoot a string shot at the 100% stuck point and attempt to back-off.
   A) Condition the mud and washover to the top of the packer.
   B) Condition the mud and pull out of the hole.
   C) Pick up an overshot and jars.
   D) Go in the hole, grab the fish and pull it out of the hole.

c- Annular Fluid is Mud

1) If the packer is stuck due to dehydrated drilling mud in the annulus:
   A) work the tubing to find the free point by stretch charts. [**G-**, **b-**]
   B) back-off at the free point and circulate thoroughly.
   C) sting back into the tubing and work to get the free point deeper.
   D) Repeat steps A), B), and C) until the packer is reached.
2) If making progress, continue until reaching a 100% stuck point.
   A) Back-off.
3) If not making progress, go into the hole with enough wash pipe to get to the packer.
   A) Once washover is accomplished down to the packer, POOH and pick up an extension, an overshot with a pack-off grapple, and a set of jars.
   B) Go in the hole and circulate above the packer.
   C) Grab the fish, circulate, jar, and POOH with the fish.

4) Steps 1), 2), and 3) can also be applied to fishing for a mud-stuck packer with weighted (gelled) polymer fluid in the annulus.
   A) This may be the cheapest route, but all of the problems arise while trying to sting back into the tubing after backing-off.
   B) If this is the problem, decide whether or not it is due to:
      a) a crooked hole.
      b) helix (bent) tubing.
      c) the string shot ballooning the end of or otherwise damaging the tubing to the point where it cannot be used to sting back into the tubing (box end of the last joint).
   C) A "blind" back-off can be accomplished by backing-off the tubing at will.
      a) If the tubing backs-off deep enough, a jar can be made up in the tubing string and run into the hole.
      b) Jarring on the packer after stinging back into the tubing can sometimes get the packer loose.

G- LOCATING THE FREE POINT

a- Formula Method

L = [E x e x A] ÷ [12 x P]

1) Where:
   - L = the free length of the drill pipe in feet
   - E = 30,000,000: the modulus of elasticity of steel in psi
   - e = the stretch of the pipe in inches
   - A = the cross-sectional area of the pipe in square inches
   - P = the difference between the maximum and minimum pulls in pounds

2) Procedure
   A) Ensure that the weight indicator is accurate.
   B) Select a base point (from which to take measurements) that will not settle when the load on the mast is increased.
      a) This point is usually on the top of the wellhead rather than the rotary table so that settling of the mast and substructure due to the imposed strain will not affect the base point.
   C) Take a reading from the weight indicator that corresponds to a pull on the pipe which is slightly more than enough pull to take all the slack out of the pipe.
      a) This value will represent **Wmin**.
   D) Take another reading from the weight indicator that corresponds to a maximum pull that is considered safe.
      a) Take into consideration the condition of the mast and pipe.
      b) This value will represent **Wmax**.
   E) Reduce the strain on the pipe until the tension is something less than Wmin and then pull up again until the indicator reads Wmin, being careful to pull up to this reading without slacking off.
      a) Mark the pipe point A.
   F) Pull up to some tension greater than Wmin and slack off until the indicator reads Wmin.
      a) Mark the pipe point B.
   G) Repeat E) and F) at Wmax and call these points C and D.
   H) Mark a line midway between points A and B and another midway between points C and D.
      a) These points will become F and G.
   I) The distance between F and G is the stretch in the pipe due to the change in tension of Wmax and Wmin.
   J) Using the above equation, L can now be calculated.

b- Stretch (Graph) Method

1) Procedure

A) If the string is assumed to be stuck near the bottom, calculate the weight of the string by multiplying the total length of the string by the weight per foot.

B) Pull on the string to that value.

C) Stretch and mark the string at several pull values.

a) 10, 20, 30 or 40 thousand pounds

b) not to exceed the minimum yield strength of the pipe

c) Follow the procedure given previously for marking the pipe and determine the average stretch for the various pull values.

d) Measure the stretch in inches.

D) Plug the various stretch values into the corresponding formula that matches the pull value.

a) Where:

D = depth of the free point in thousands of feet
S = stretch in inches

b) $2^3/8$ inch Tubing

10,000 pounds pull: $D = 0.322 \times S$

20,000 pounds pull: $D = 0.165 \times S$

30,000 pounds pull: $D = 0.110 \times S$

c) $2^7/8$ inch Tubing

10,000 pounds pull: $D = 0.450 \times S$

20,000 pounds pull: $D = 0.225 \times S$

30,000 pounds pull: $D = 0.157 \times S$

40,000 pounds pull: $D = 0.114 \times S$

H- STRING SHOT AND BACK-OFF

a- General

1) Work the string until the torque can be transferred to the stuck point.

2) Run a string shot to the desired depth but opposite a tubing coupling or tool joint as indicated by the collar locator.

3) Accomplish back-off by the application of left-hand torque in the string.

A) If the left-hand torque is applied at the neutral point (not in tension or compression at the place of the shot) the concussion of the explosion will cause the threaded connection to jump the threads.

4) A properly handled back-off will not damage pipe, threads or couplings.

b- Application of Left-hand Torque

1) Check the rig equipment to ensure that it is safe and in good working order.

2) Make sure that the right-hand joints are tight.

A) If the tubing is in good enough shape, in graduated intervals:

a) apply right-hand torque 8 rounds in and 7 to 8 rounds back.

b) (i.e. - 2 in, 0 back; 2 in, 0 back; until 8 in then 6 or 7 back)

3) Apply left-hand torque.

A) After estimating the free point using the stretch method (see below), pick up the weight down to within 2 joints of the stuck point plus the weight of the blocks.

B) If the kelly is in place, turn the drill pipe to the left with the rotary.

a) minimum 6 turns (rounds), maximum 8 turns (rounds)

C) Hold.

4) Using power tongs or a power sub, put additional left-hand torque on the drill pipe.

A) Manually hold back torque with one set while pulling more torque with the other.

c- Safety Checks

1) Tong and Slip Dies
   A) clean
   B) sharp
   C) the correct size to bite and hold the pipe
2) Safety lines on tongs should be wireline cables, in good condition, with the end loops properly fastened with wire clamps.
3) The sliphandles should be tied together with soft line because it is possible for the pipe to break high when back torque is being applied.
   A) If this is so, the slips would be thrown clear and the pipe dropped.
4) When a jerk line must be used to apply left-hand torque, in lieu of reverse gear on the rotary, be sure that the line is:
   A) not frayed.
   B) long enough to allow several wraps with plenty of rope remaining.
5) When applying torque, the elevators should be relatched below the tool joint so that the pipe can rotate freely.
   A) The hook should be locked when the pipe is being rotated while the weight is on the slips.

I- FISHING TOOLS { 58 }

a- List

1) Spears
2) Overshots
3) Cutters
   A) internal
   B) external
4) Milling Tools
   A) bladed
   B) tapered
   C) piloted
   D) flat bottom
5) Taps and Die collars
6) Wash Pipe
   A) washover pipe overshot (releasable)
   B) washover pipe back-off connector
   C) washover pipe drill collar spear
7) Accessories
   A) bumper jar
   B) mechanical jar
   C) hydraulic jar
   D) jar accelerator
   E) hydraulic pull tool
   F) reversing tool
8) Safety Joints
9) Junk Retrievers
10) Impression Blocks

J- DOWNHOLE COMPATIBILITY

a- Recommended Minimum Clearance

	Between Open Hole and Wash Pipe OD	**Between Wash Pipe ID and the OD of the Fish**
Gulf Coast	1/2 inch	1/8 inch
West Texas	1/4 inch	1/8 inch

b- Equipment Size Requirements

1) Legend
   A) Common sizes of wash pipe available for oil field use.
   B) Minimum hole sizes (or casing sizes) that will accommodate this wash pipe and keep the recommended clearance.
   C) Drill collar sizes that will allow the wash pipe over and keep the minimum recommended clearance.
   D) Drill pipe sizes that will allow the wash pipe over and keep the minimum clearance recommended between the wash pipe and the drill pipe, and the wash pipe and the hole.

Wash Pipe		Hole (Casing)	Drill Collar		Drill Pipe		
OD	ID		OD	Type Conn	Size	WT	OD Conn
2 1/4"	1.995"	2 7/8"					
3 3/4"	3.250"	4 1/2"			2 3/8"	4.85#	3 1/8"
4"	3.428"	5" (18#)	3 1/8", 2 3/8"	reg 2 3/8" PAC	2 3/8"	6.65#	3 1/4"
4 3/8"	3.750"	5 1/2" (23#)	3 1/2", 2 3/8"	IF			
4 1/2"	3.826"	5 1/2" (13#-20#)					
5 1/2"	4.892"	6 5/8" (17#-28#)			2 7/8" 2 7/8"	6.85# 10.4#	4 1/8" 4 1/4"
5 3/4"	5.124"	7" (29#-38#)	4 1/8", 2 7/8"	IF	3 1/2" 3 1/2" 3 1/2"	9.50# 13.3# 15.5#	4 3/4" 4 3/4" 5"
6"	5.352"	7" (17#-26#) (all 7 5/8")	4 3/4", 3 1/2"	IF			
7"	6.276"	8 5/8" (all wts)	6 1/4", 4 1/2"	XH	4" 4" 4"	11.85# 14.00# 15.70#	6" 6" 6"
7 3/8"	6.625"	8 5/8" (all wts)			4 1/2" 4 1/2" 4 1/2"	13.75# 16.60# 20.00#	6 3/8" 6 1/4" 6 1/4"
7 5/8"	6.875"	8 5/8" (24#-32#)					
8 1/8"	7.249"	9 5/8" (all wts)			5" 5" 5 1/2" 5 1/2"	19.5# 25.6# 21.9# 24.7#	7" 7" 7" 7"
8 5/8"	7.825"	9 5/8" (29#-36#)					
9"	8.124"	10 3/4" (all wts)			6 5/8"	25.2#	8"
10 3/4"	9.850"	11 3/4" (38#)					

K- MILLING

a- General

1) Drilling rates are highly variable.
2) If torque is not observed while milling, biting is not taking place.
3) Adjust the weight on the mill according to the rpms.
   A) too slow - decrease the weight
   B) too fast - increase the weight

b- Abbreviations

1) Av CR - average cutting rate in feet per hour
2) Av WOB - average weight on bit in 1,000 pounds (K)
3) Chp App - chip appearance
4) Mud Min Vis - minimum viscosity of mud in centipoise (cps)
5) Tbl Spd - rotary table speed in rotations per minute
6) WOB - weight on bit in 1,000 pounds

c- Operating Recommendations

	Tbl Spd	WOB	Mud Min Vis
Tapered Mills	50 to 80	2 to 4	60
Junk Mills	100	4 to 10	60
Pilot Mills	125	5 to 10	60

d- Milling Rates (feet per hour)

	Junk Mills	Pilot Mills
Casing	2 - 4	4 - 10
Drill Pipe	2 - 6	2 - 4
Drill Collars	1 - 2	1 - 2
Packers	4	N/A
Bits, Cones, etc.	2 - 4	N/A
General Junk	3 - 5	N/A
Wash Pipe	2 - 4	4 - 10

e- Casing Cutting Characteristics (Pilot Milling)

	Av CR	Tbl Spd	Av WOB	Chp App
H40	1 to 2	75	2	scaly, dull
J55	4 to 10	125	6	medium length, fine
N80	6 to 12	125	6	long, stringy, sharp
P110	5 to 14	150	8	long, stringy, sharp

9 - MUD LOGGING

TABLE OF CONTENTS

A- DUTIES OF A WELL SITE ANALYST {61}

a- Monitor the Mud Logging Data

1) continuously monitor total gas concentration (hot wire)
2) gas analysis (using a gas chromatograph)
3) show analysis
4) cuttings analysis
5) sample catching
6) sample analysis
7) fluorescence identification
8) lithology description
9) draft the logging reports
10) correlate the data with offset wells

b- Monitor the Drilling Data

1) pit volume
2) relative mud flowrates
3) trip fill-up
4) pump speed (number of strokes per minute)
5) flowline temperature
6) resistivity of the mud
7) rotary speed
8) hook load (weight on bit)
9) mud weight (in and out of the hole)
10) pump pressure
11) total bit revolutions
12) bit drilling time
13) poison gas sensing
14) rate of penetration

c- Analyze the Data

1) shale density calculations
2) dc exponent calculations [**Chapter 7: C-, r- and D-, a-**]
3) pore pressure analysis
4) fracture gradient prediction
5) casing seat recommendation
6) equivalent circulating density calculations
7) analysis of the bit hydraulics
8) surge and swab pressure calculations
9) slip velocity calculations
10) weight and rotary speed recommendations
11) assist in well control in the event of a kick

B- EQUIPMENT USED IN MUD LOGGING {62}

a- List

1) Gas Trap
   A) Components of a "Gas Trap" Gas Recovery System
      a) housing
         1. agitator
         2. agitator motor
         3. air port (hole for air to enter)
         4. vacuum port (hole for air/gas mixture to leave)
      b) vacuum system
         1. filter/dryer and filter/dryer housing
         2. vacuum pump
         3. pressure regulator
      c) flowmeter
      d) gas detector (hot wire)
      e) exhaust
      f) ammeter
         1. registers gas units on a gauge
      g) chart recorder
         1. records gas units on a graph

B) Operation

a) The ammeter measures the ampere fluctuations caused by changes in temperature.

b) Temperature changes are caused by:

1. the type and relative amounts of gas flowing through the detector.
2. hydrocarbons catalyzing on the platinum filament housed within the milliammeter.

2) Back-up Hot Wire

A) required when the first goes off-scale due to being overloaded

3) Time/Depth Recorder

A) records the drilling depth and the time

B) used to calculate drilling speed

4) Pump Stroke Counter

A) After calculating the correct lag time, gas shows and sample analysis can be attached back to the correct depth.

5) Pit Level Indicator

A) an early warning device used when a gas show precedes a flow

6) Microscope

A) used to look at samples

7) Ultraviolet Lamp

A) used to check for fluorescence

B) standard strength:

a) oilfield use - 2,700 Angstroms

b) most other industrial uses - 3,600 Angstroms

8) Workspace

A) a sink and countertop where samples can be cleaned, sieved and dried

C- CONTENTS OF A TYPICAL MUD LOG { 63 }

a- Rate of Penetration Curve

1) dates
2) drill bit types
3) weight on bit
4) rotary speed
5) pump pressure
6) mud properties

A) viscosity

B) chloride concentration

C) mud weight

b- Cuttings Identification and Description

1) Identification

A) Cuttings are:

a) usually identified by generally accepted symbols broken down by percentages, normally in 10% increments.

1. e.g. - 90% sand, 10% shale

b) described in detail.

1. e.g. - shale, light grey to light green, soft, flaky and calcareous with abundant shell fragments: **or**
sh, ltgy - ltgn, sft, flky, calc, /abnt shl frag

2) Abbreviations Used in Sample Descriptions {48}

abt	about
abv	above
abnt	abundant
acic	acicular
aglm	agglomerate
agg	aggregate
alg	algae, algal
alt	altered, altering
amor	amorphous
amt	amount
ang	angular
anhed	anhedral
anhy, an	anhydrite, anhydritic
apr	apparent
aprs	appears
aprox	approximate
arag	aragonite
aren	arenaceous
arg	argillaceous
ark	arkose
asph	asphalt
@	at, around, approximately
av	average
bnd	banded
bar	barite
bas	basalt
bd	bed
bdd	bedded
bdg	bedding
bent	bentonite
biot	biotite
bit	bitumen, bituminous
blk	black
blky	blocky
bl	blue
btry	botryoidal
bldr	boulder
brac	brachiopod
brec	breccia
bri	bright
brit	brittle
brn	brown
bry	bryozoa
calc	calcite, calcareous
carb	carbonaceous
cav	cavernous
cvg	caving
cmt	cement
cntr	center
ceph	cephalopod
chal	chalcedony
chk, ck	chalk
cht	chert
chit	chitin
clas	clastic

cly, cl	clay
clyst	claystone
cln	clean
clr	clear
cls	cluster
c	coarse
cbl	cobble
col	color
com	common
cpct	compact
cncn	concentric
conch	conchoidal
conc	concretion
cgl	conglomerate
cono	conodont
ctc	contact
cntrt	contorted
coq	coquina
cov	covered
cren	crenulated
crev	crevice
crnk	crinkled
crin	crinoid
xbd	cross-bed
xlam	cross-laminated
crpxl	cryptocrystalline
crpgr	cryptograined
xl	crystal
ctgs	cuttings
dk	dark
dd	dead
deb	debris
decr	decrease
dend	dendritic
dns	dense
dtrm	determine
dtrl	detrital
dia	diameter
dif	difference
dism	disseminated
dolc	dolocast
dol	dolomite
dolmd	dolomold
drsy	druse, drusy
rthy	earthy
ech	echinoid
elip	elliptical
elg	elongate
embd	embedded
enl	enlarged
equiv	equivalent
euhed	euhedral
evap	evaporitic
exp	exposure, exposed
extr	extrusive

fac	faceted
fnt	faint
fr	fair
flt	fault
fau	fauna
fld	feldspar
fe	ferruginous
fib	fibrous
fig	figured
f	fine
fis	fissile
flgy	flaggy
flk	flake
flky	flaky
flat	flattened
fltg	floating
fluor	fluorescence
fol	foliated
foram	foraminifera
fm	formation
fos	fossil
frac	fracture
frag	fragment
frs	fresh
fri	friable
fros	frosted
fus	fusulinid
gab	gabbro
gast	gastropod
gl	glassy
glau	glauconite
glos	gloss
gns	gneiss
g	good
grd	grade
gr	grain
grnt	granite
gran	granular
grnl	granule
grap	graptolite
gvl	gravel
gy	gray
gywke	graywacke
gsy	greasy
gn	green
grty	gritty
gyp	gypsum
hky	hackly
hd	hard
hvy	heavy
hem	hematite
hex	hexagonal
hi	high
hztl	horizontal
hydc	hydrocarbon

ig	igneous
imbd	imbedded
imp	impression
incl	inclusion
incr	increase
indst	indistinct
ind	indurated
intbd	interbedded
intcl	intercalated
intxl	intercrystalline
intfr	interfingered
intgra	intergranular
intgwn	intergrown
intlam	interlaminated
intstl	interstitial
intv	interval
intfm	intraformational
intr	intrusion
invrtb	invertebrate
Fe	iron
Fe-st	ironstone
ireg	irregular
irid	iridescent
jasp	jasper
jtd	jointed
jts	joints
kao	kaolin
lam	laminated
lrg	large
lav	lavender
lchd	leached
ldg	ledge
len	lentil
lt	light
lig	lignite
ls	limestone
lmy	limey
lith	lithologic
ltl	little
lg	long
lse	loose
low	lower
lmpy	lumpy
lstr	luster
magn	magnetic
mrlst	marlstone
mar	maroon
mas	massive
mat	material
mtx	matrix
max	maximum
m	medium
mbr	member
meta	metamorphic
mica	micaceous
micxl	microcrystalline

micfos	microfossil
micgr	micrograined
mic-mica	micro-micaceous
mid	middle
mnrl	mineral
min	minimum
mnr	minor
mnut	minute
mod	moderate
mol	mollusca
mdst	mudstone
Musc	Muscovite
nac	nacreous
n	no, non
nod	nodule
num	numerous
obj	object
och	ochre
od	odor
o	oil
o.sd	oil sand
o.stn	oil stain
olv	olive
ooc	oolicast
ool	oolite
oom	oomoldic
op	opaque
orng	orange
org	organic
orth	orthoclase
ost	ostracode
ox	oxidized
pt	part, partly
ptg	parting
prly	pearly
pbl	pebble
pbly	pebbly
plcy	pelecypod
pel	pellet
perm	permeability
pet	petroleum
phos	phosphate
pk	pink
p-p	pin-point
piso	pisolite
pit	pitted
plag	plagioclase
pl fos	plant fossils
plas	plastic
plty	platy
pol	polished
p	poorly
porc	porcelaneous
por	porosity
pos	possible
pred	predominant

pres	preserved
prim	primary
pris	prism
prob	probable
prom	prominent
psdo	pseudo-
purp	purple
pyr	pyrite
pyrbit	pyrobitumen
pyrclas	pyroclastic
qtz	quartz
qtzt	quartzite
qtzc	quartzitic
qtzs	quartzose
rad	radiate
rng	range
rr	rare
reg	regular
rmn	remains
repl	replacement
resd	residue
rsns	resinous
rhmb	rhombic
rk	rock
rd	round
rbly	rubbly
spl	sample
sd	sand
sdy	sandy
ss	sandstone
sat	saturated
sc	scales
scs	scarce
scat	scattered
sch	schist
scol	scolecodonts
sec	secondary
sed	sediment
sel	selenite
shad	shadow
sh	shale
shy	shaley
sid	siderite
sil	silicious
slky	silky
slt	silt
sltst	siltstone
slty	silty
sz	size
slab	slabby
sl	slight
s	small
sm	smooth
sft	soft

sol	solution
sort	sorted
srtg	sorting
spec	speck
sphal	sphalerite
sph	spherulite
spic	spicule
splty	splintery
spg	sponge
spr	spore
sp	spot
stn	stain
stip	stippled
st	stone
strat	strata
str	streak
stri	striated
strg	stringer
strom	stromatoporoid
struc	structure
styl	stylolite
sbang	subangular
sbhed	subhedral
sbrd	subround
suc	sucrose
S	sulphur
surf	surface
tab	tabular
tex	texture
thk	thick
thn	thin
thru	throughout
tt	tight
tr	trace
trnsl	translucent
trnsp	transparent
trilo	trilobite
Trip	Tripoli
tub	tubular
tuf	tuffaceous
unconf	unconformity
uncons	unconsolidated
up	upper
var	variable
vcol	varicolored
vgt	variegated
vrvd	varved
vn	vein
vrtb	vertebrate
v	very
ves	vesicular
vit	vitreous
volc	volcanics
vug	vug, vuggy, vugular

wtr	water
wvy	wavy
wxy	waxy
wthr	weather
w	well
wh	white
/	with
yel	yellow
zn	zone

3) Abbreviations Used in Oil and Gas Scout Reports { 48 }

abd, abnd	abandoned
bld	bailed
BFPH	barrel of fluid per hour
BPD, b/d	barrel per day
BPH	barrel per hour
BO	barrel of oil
BOPD	barrel of oil per day
BW	barrel of water
BWPD	barrel of water per day
BWPH	barrel of water per hour
bl	black
BHP	bottom-hole pressure
B/	bottom of
brkn	broken
CP	casing pressure
chk	choke
circ	circulate
comp	completed
congl	conglomerate
crd	cored
crg	coring
xln	crystalline
CFG	cubic feet of gas
CFGPD	cubic feet of gas per day
dk	dark
DF	derrick floor
dol, dolo	dolomite
DC	drill collar
DP	drill pipe
DST	drill stem test
drlg	drilling
D&A	dry and abandon
e log	electric log
elev	elevation
est	estimated
fl/	flowed
FP	flowing pressure
FIH	fluid in hole (or finish in hole)
fluor	fluorescence
fm	formation
frac	fractured

G&OCM	gas- and oil-cut mud
GC	gas cut
GCM	gas-cut mud
GIH	go in hole
GOR	gas/oil ratio
gr	gray
grn	green
GL	ground level
HOCM	heavily oil-cut mud
HGOR	high gas/oil ratio
ig	igneous
IP	initial production
KB	kelly bushing
KO	kicked-off
lse	lease
lm	lime
ls	limestone
loc	location
md	millidarcies
MICT	moving in cable tools
MIR	moving in rig
MI/RU	move in/rig up
MO	moving out
NS	no show
O&G	oil and gas
O&GCM	oil- and gas-cut mud
O&SW	oil and salt water
OC	oil cut
OCM	oil-cut mud
Ool	oolitic
OF	open flow
OH	open hole
pkr	packer
perf	perforated
perm	permeability
pk	pink
PL	pipeline
P&A	plugged and abandoned
PB	plugged back
por	porosity
psi	pounds per square inch
POP	putting on pump
POOH	pull out of the hole
qtz	quartz
qtze	quartzite
rmg	reaming
rec	recovered
RUCT	rigging up cable tools
RUR	rigging up rotary rig
RP	rock pressure
RT	rotary table
rng	running
RIH	run in the hole

sx	sacks
SW	salt water
S/T	sample tools
sd	sand
sdy	sandy
ss	sandstone
sat	saturated
Sec	section
sed	sediment
seis	seismic
SP	spontaneous potential
sh	shale
SG	show of gas
SO	show of oil
SO&G	show of oil and gas
SO&W	show of oil and water
SDFO	shut down for orders
SDFN	shut down for night
SDON	shut down overnight
SDFW	shut down for weather
SI	shut-in
SIBHP	shut-in bottom-hole pressure
SIP	shut-in pressure
SSO	slight show of oil
spd	spudded
squ	squeeze
stn	stain
stds	stands
strks	streaks
sul wtr	sulphur water
sur	survey
swbd	swabbed
swbg	swabbing
tstg	testing
MCF	thousand cubic feet
T/	top of
TD	total depth
Twp	township
TP	tubing pressure
unconf	unconformity
WOC	waiting on cement
WO/O	waiting on orders
W/C	water cushion
wh	white
WC	wildcat

c- Total Gas Concentration

1) Take readings continuously using a hot wire.
2) Plot the readings on continuous-feed graph paper.

d- Relative Concentration of Total Gas Components

1) Perform a gas analysis using a gas chromatograph.

e- Shows and Their Significance

1) A drilling break indicates the presence of oil and gas. See **E-** below.

D- MUD LOGGING UNIT PROBLEMS { 62 }

a- Mud Contaminants

1) Cavings:
   A) exist as a result of heaving of the hole somewhere other than bottom.
   B) are recognized by their shape.
      a) usually long and splintery
      b) match the lithology of a zone somewhere up the hole
   C) cause problems because they foul up the current cuttings analysis.
2) Recycled cuttings:
   A) occur because the cuttings were not originally completely removed.
   B) are recognized as small, abraded, rounded fragments.
3) Mud chemicals
   A) Lignosulphonate resembles lignite.
   B) Bentonite gel resembles some clays (e.g. - montmorillonite).
   C) lost circulation material (e.g. - hulls, fibers, mica, etc.)
4) Cement:
   A) may look similar to siltstone.
   B) stains purple in a phenolpthalein solution.
      a) method of identification
5) Plastic pipe coating:
   A) displays a variable fluorescence.
6) Mud additive degradation:
   A) produces methane as a by-product.
7) Pipe dope:
   A) displays a very bright fluorescence.
8) Diesel oil:
   A) displays a dull fluorescence.
   B) contains heavy hydrocarbon gases.
9) Coal seam:
   A) yields a show that is high in methane and ethane.
10) Some polymer-based muds and chemicals, such as Drispac, may cause saturation on the hot wire detector.
11) Diamond or PDC bits produce cuttings with difficult-to-identify rock properties.

b- Circulation

1) An air port that allows air to enter into the gas trap becomes blocked with mud cake.
2) The agitator motor malfunctions.
3) The possum-belly or ditch becomes blocked with cuttings.
4) The gas trap itself is filled with cuttings.
5) The impellers on the agitator become damaged.
6) The vacuum inside the vacuum line becomes weak for some reason.

c- Gas Loss

1) Losses from the bell nipple.
2) The flowline is not full.
3) The flow of mud down the flowline is too turbulent due to slope changes from across the bell nipple to the possum-belly.
4) The flowline is open and vents to the atmosphere.
5) The flowline dumps well above the level of the mud in the possum-belly.

d- Drilling Break

1) a false indication of a drilling break when the Driller closes a bumper sub in the drilling string

e- Carbide Absent

1) a large increase in total gas or petroleum vapors when a carbide reading is forgotten or surfaces early

f- Washout

1) an increase in gas at the surface due to a hole washout

g- Trip/Connection Gas

1) a high total gas with low petroleum vapors and no drilling break, etc., caused by trip or connection gas

E- SHOW EVALUATION

a- Fluorescence

1) The Color of Fluorescence and Its Usual Meaning
will sometimes vary with geographical area

Color	Likely Interpretation
gold	oil
white	fresh oil
bright yellow	high gravity oil
blue	condensate
none	dry gas
dull gold	oil-base mud (obm)
bright gold	oil-base mud filtrate
dull gold	mineral fluorescence
brown	asphalt
red	extremely heavy petroleum crude
orange	a little lighter than the crude that fluoresces red
green	rare, but could be a heavy condensate

2) The Color of Fluorescence vs. Gravity

Color	Possible API Gravity
brown	1 - 15
orange	15 - 25
yellow	25 - 35
white	35 - 45
blue	45 +

3) Mineral Fluorescence

Rock	Color
dolomite	yellow to yellowish brown
limestone	brown
sandy limestone	yellowish brown
chalk	purple
marl	light brown to yellow grey
fossils	white to yellow to yellow brown
anhydrite	greyish blue to grey

b- Cut Reaction

1) Intensity

A) none
B) blooming
C) streaming
D) milky
E) spotty
F) streaky
G) patchy
H) uniform
I) residual
J) a combination of any of the above

2) Rate
- A) flash
- B) fast
- C) slow

c- Stain

1) Oil Stain Description
- A) none
- B) spotty
- C) streaky
- D) patchy
- E) uniform

2) Color
- A) brown
  - a) light
  - b) medium
  - c) dark
- B) black

d- Odor
1) none
2) slight
3) medium
4) strong

e- Fracture
1) horizontal
2) vertical

f- Bedding, if present
1) thin
2) thick
3) irregular

g- Show Analysis

interpretations will vary with geographical area

1) Compounds as Determined by Gas Chromatograph Analysis

Methane	C1
Ethane	C2
Propane	C3
Butane	C4
Pentane	C5

2) Methane/Ethane Ratio Methods

A) Method I

a) **If [C1 ÷ C2] =**

If [C1 ÷ C2] =	The Interpretation is:
1 - 2	residual oil
2 - 6	oil (gravity 20 - 45 API)
6 - 12	gas condensate
12 - 50	dry gas
50 or >	low permeability zone

b) If C3 or C4 is greater than C2 then the zone is wet.

B) Method II

a) Ratio Value vs. Interpretation

Ratio	Oil	Gas	Non-Productive
C1 ÷ C2	2 - 10	10 - 35	< 2 and > 35
C1 ÷ C3	2 - 14	14 - 82	< 2 and > 82
C1 ÷ C4	2 - 21	21 - 200	< 2 and > 200

b) If [C1 + C2] falls in the oil column but [C1 + C4] falls in the gas column, the zone may be non-productive.

c) If any ratio is lower than the one above it, the zone is probably not productive.

d) If [C1 + C4] is lower than [C1 + C3], the zone is probably water productive.

3) Haworth, Sellens and Gurvis Method { 64 }

A) This method relies only on relative concentrations of hydrocarbons and not on the absolute quantities.

B) Ratios

a) Gas Wetness Ratio Percent (**GWR%**)

GWR% = [(C2 + C3 + C4 + C5) + (C1 + C2 + C3 + C4 + C5)] x 100

GWR%	Probable Meaning
00.0 - 00.5	Non-productive - non-potential dry gas
00.5 - 17.5	Potential Gas - increasing density with increasing GWR%.
17.5 - 40.0	Potential Oil - increasing density with increasing GWR%
40 + above	Residual Oil

b) Light to Heavy Ratio (**LHR**)

LHR = [C1 + C2] + [C3 + C4 + C5]

1. This ratio value decreases with the density of the fluid.

c) Oil Character Qualifier (**OCQ**)

OCQ = [C4 + C5] + C3

1. This ratio is most valuable when used in situations that are otherwise considered borderline.

C) Interpretation

a) The values of the **GWR%**, the **LHR**, and the **OCQ** ratios are best utilized in the interpretation of a show in the manner in which they compare to each other.

b) Interpretation by Comparison of the **LHR** and the **GWR%**

1. Determine the GWR%.
   A. Place it into one of the four categories.
      a. Non-productive
      b. Potential Gas
      c. Potential Oil
      d. Residual Oil
2. Compare the value of the LHR to the GWR% to confirm the fluid character.
   A. If the LHR is > 100, the zone is probably not productive.
   B. If the GWR% is in the gas phase and the LHR is > the GWR%; the closer the ratios, the denser the gas.
   C. If the GWR% is in the gas phase and the LHR is < the GWR%, gas/oil or gas/condensate production can be expected.
   D. If the GWR% is in the oil phase and the LHR is < the GWR%; the greater the difference between the two, the more dense the oil.
   E. If the GWR% is in the residual oil phase and the LHR is < the GWR%, residual oil is probably the interpretation.
3. Use the OCQ curve to differentiate.
   A. If the OCQ is < 0.5, gas potential is indicated and the GWR% vs. the LHR is correct.
   B. If the OCQ is > 0.5, gas/light oil or condensate is indicated.

F- ACTIONS IN RESPONSE TO A DRILLING BREAK {63}

a- List

1) Watch for a pit level gain.
2) Inform the Driller and/or the Company Representative that a drilling break has occurred.
   A) See if a flow check is required if it was not stipulated beforehand.
3) Circulate out the contents of the drilling break if the Company desires it.
4) Record the latest mud check.
5) Catch a sample just before the drilling break reaches the surface to use as a comparison.
   A) Collect the sample from the full width of the shaker.
   B) Record the gas concentration in the blender mud.
   C) Run the blender on the 100cc of mud on top of the collected sample.
      a) Record any oil on top and the amount of odor, if any.
6) Repeat 5) with 200cc of mud from the drilling break sample.
7) Ensure that:
   A) the gas detector and the gas chromatograph are still on scale.
   B) there is no gain in the pit level.
8) If it is indeed a show and the Driller has resumed regular drilling, see if the Company Representative wants to stop drilling and circulate.
   A) If the current break was fast, catch another sample.
      a) Record the exact depth of break.
      b) This sample will come in handy later.
9) Check the fluorescence of the unwashed sample.
10) Get a cut reaction on the fluorescence.
11) Record a short description of the sample.
    A) stain
    B) odor
    C) percent fluorescence
    D) cut
       a) record reaction of cut
12) Check for a pit gain.
13) Finish writing the lithological description.
    A) lithology
    B) fluorescence
       a) percent of sample
       b) color
    C) cut
       a) intensity
       b) rate
    D) stain
       a) appearance
       b) color
    E) odor
    F) fractures
    G) bedding
14) Bag and mark wet and dry samples for all depths collected.
15) Once the hole is cleaned or you are through the show, estimate the amount and type of porosity through a visual (microscopic) examination.
16) Estimate the:
    A) permeability of the zone from cuttings.
    B) gas/total gas ratio.
    C) cut reaction.
    D) hydrocarbon type.
    E) API gravity, if it is an oil show.

G- THE RELATION OF GAS CONCENTRATION TO GAS UNITS

a- Points to Remember

1) These are not standard measurements.
2) A unit of gas is only a relative concentration and not a standard quantity.

% Methane in Air	Units of Gas
0 - 2	0 - 100
2 - 4	100 - 500
10 - 20	500 - 1,000
20 - 40	1,000 - 2,000
40 - 60	2,000 - 3,000
60 - 80	3,000 - 4,000
80 - 100	4,000 - 5,000

H- LIVE OIL VS. DEAD OIL

a- Live Oil

1) contains lots of dissolved gas
2) light in color
3) not viscous
4) high cut
5) good odor

b- Dead Oil

1) no dissolved gas
2) dark color
3) viscous
4) has a slow cut
5) has odor (not strong)

I- PRODUCABILITY

a- Key Indicator

1) the way the show compares to the show obtained from drilling the same zone in an offset or nearby well with:
   A) comparable mud weights and mud systems (i.e. - total gas vs. total gas of a producing well)
   B) the subsequent results of the offset wells

10 - DRILL STEM TESTING

TABLE OF CONTENTS

A- GENERAL

a- Definitions

Drill Stem Test - an evaluation of a formation's ability to produce. The test is performed through the drill string.

Reversing Out - pumping drilling mud down the annulus and up the drill pipe following a mis-run, as in a well control problem or other mechanical problem. Because the mud contaminates the formation flow a decision of whether or not to run another Drill Stem Test (DST) must be made.

b- Importance

1) Because of the importance of a DST in determining the producibility of a zone, the test planning must be done with care.
2) Each step must be properly executed to obtain a successful DST.

B- PHASES OF A DRILL STEM TEST

a- Drill the Zone of Interest

1) Offset logs and subsurface maps were used to estimate the depth of the well's producing zone.
2) Pay close attention as you drill closer to the expected depth of the zone of interest (zoi).
3) Once the zoi has been drilled:
   - A) collect samples.
   - B) check the samples for shows.
   - C) decide if a DST is warranted.
     - a) Company policies differ.
     - b) Generally:
       1. is there a show?
       2. how good is the show?

b- Condition the Mud and the Hole

1) Properly Condition the Drilling Mud
   - A) Mud Weight:
     - a) must be heavy enough to prevent the well from coming in.
     - b) must balance, as close as is possible, the pressure at the zoi.
       1. enables tools to be operated properly
       2. the differential applied across the face of the zone is minimum
       3. mud filtrate invasion is reduced
   - B) Mud Solids:
     - a) should be kept to a minimum.
       1. prevents undesirable, thick, soft filtercake
   - C) Gel Strength
     - a) Maintain the minimum gel strength needed to properly support the cuttings.
       1. The mud should be thixotropic enough to prevent settling.
     - b) Keep the viscosity low in order to adequately clean the hole during circulation.
   - D) Fluid Loss
     - a) Maintain a low fluid loss in order to control filtrate build-up.
     - b) 6cc - 10cc per 30 minutes while cutting the zone should be sufficient.
   - E) Before pulling out the hole for a DST, circulate long enough to remove all of the cuttings and viscous mud.

2) Properly Condition the Hole

A) Good hole conditioning results in:

a) fewer mis-runs.

b) better test results.

c) greater safety.

d) a reduced chance of a blow-out, lost circulation or stuck pipe.

B) A close tolerance (about 1") between the ID of the hole and the OD of the test tool requires a full gauge hole and a clean wellbore in order for the assembly to reach bottom in an undamaged, unplugged condition.

a) If fill is allowed to collect on bottom, the test tool must slide to bottom, plugging the test ports.

b) Wall cake and cuttings shoved ahead of the packer might plug the perforations in the anchor pipe or the choke in the tool when the valves are opened.

3) DST Failures

A) One half of the DST failures and incomplete tests are caused by either:

a) improperly conditioned mud.

b) the poor condition of the hole.

B) Many DSTs fail because of the improper use of rubbers on the DST tool.

a) If the wrong set of rubbers is used for the particular set of hole conditions, a packer seat is unlikely.

b) Test results will be inconclusive.

C) Short trips are usually recommended.

c- Packer Seat and Fluid Cushion

1) Choosing a Packer Seat

A) Good Packer Seats

a) unfractured limestones or consolidated sands

B) Poor Packer Seats

a) shales, shaley sands, and unconsolidated sands

1. subject to sloughing or washing out

C) If a good packer seat is not selected, a good DST is less likely.

D) It is usually not a good practice to attempt to reset a failed DST packer.

a) tends to get stuck

2) Choosing a Fluid Cushion

A) The fluid cushion inside the drill pipe during a DST is:

a) usually water.

1. maximum recommended pressure differential - 5,000 psi

A. The chance of a failure due to packer leakage is greater at higher pressures.

2. Surface flowing pressures should be maintained within the safety limits determined prior to the test.

A. based on:

a. test depth

b. expected pressure calculated from offset wells

c. local knowledge

b) sometimes mud.

1. Depending on the expected pressure, rely on local knowledge to help with the decision.

A. Talk to the Drilling Contractor and the testing company.

B) The purpose of the cushion is to:

a) prevent drill pipe collapse.

b) prevent unconsolidated formations from caving in when the test valves are opened.

c) maintain control over high pressure and high volume wells by bringing them in slowly.

d) prevent the dehydration of the mud when the valve is opened on high temperature wells.
e) help relieve the sudden change in differential pressure across the packer seat.

d- Review Safety Procedures

1) A meeting should be held prior to preparing the rig for a DST.
   A) Everyone participating in the DST should be present.
2) Discuss thoroughly and reinforce the already decided appropriate measures regarding:
   A) the person in charge.
   B) individual responsibilities.
   C) safety factors.
   D) exits.
   E) wind direction.
   F) warning signs.
   G) smoking restrictions.
3) All personnel should have appropriate protective clothing and equipment.
   A) safety hat
   B) safety shoes
   C) safety slide for the Derrickman
4) Personnel should follow all safety regulations of the Drilling Contractor, the service company, and governmental control agencies.
5) Is hydrogen sulfide expected at the surface after the DST?
   A) If so, take extreme precautions. [**Volume 3, Chapter 37, B-**]

e- Prepare the Drilling Rig

1) The cellar should be drained.
2) BOPs should be:
   A) checked for proper operation.
   B) pressure tested before going into and coming out of the hole prior to the DST.
3) Fill lines:
   A) must be installed on the bell nipple above the BOPs to keep the casing full of mud.
      a) *Use for this purpose only!*
      b) Kill lines should be separate installations.
   B) should be suitable for keeping the hole full while the drill pipe is pulled after running the DST.
4) A flare line to the pits should be tightly installed to:
   A) carry any hydrocarbons produced during the test away from the rig.
   B) prevent hydrocarbons from accumulating in low places.
5) Check all fire extinguishers.
6) Extinguish or shut off all potential ignition sources.
   A) heating stoves
   B) open fires
   C) Engine exhausts should have adequate water spray connections.
7) In case of a blow-out or other downhole problem, the testing company should provide two methods of reversing out, preferably both an on-bottom and an off-bottom device.
8) Check the weight of the mud.
   A) The mud should be conditioned to withstand:
      a) the anticipated pressure.
         1. must be heavy enough to hold pressure in the formation while pulling the pipe
      b) any conditions that may be encountered.
         1. must have viscosity properties that will assist in the prevention of swabbing of the zone while pulling out of the hole with the test tool

f- DST String Set-up

1) All companies that provide DST services should be capable of selecting the equipment to match the job.

top to bottom

A) drill string

B) jars

a) As a precautionary measure, it is often recommended that a set of jars be run above the test tool and possibly above the collars.

C) DST tool

D) anchor pipe

2) Testing should be:

A) avoided during electrical storms.

B) started, circulated out, and pulled only during daylight hours.

3) The Tester should instruct the Driller on the procedures for closing the test tool should control of the well become jeopardized.

A) The Driller should pick up on the string to close most hydraulic testers.

g- Go in the Hole

1) Be patient when going in the hole with the test tool.

A) Do not get in a hurry.

B) The smaller clearance in the annulus increases the downhole pressure due to the piston effect.

2) Set the tool in consultation with the Testing Company.

h- Conduct the Test

1) Watch for a kill line fluid level drop in the annulus.

A) indicates:

a) packer failure

b) a hole in the drill pipe

2) Run a minimum of 2 flow periods.

3) Normal Test Cycle

A) 30 minute initial flow period

B) 90 minute initial shut-in period

C) 90 minute final flow period

D) 180 minute final shut-in period

i- Liquid Test Procedure

1) Collect the information.

A) Well Data

a) drill pipe size in inches

b) drill collar size in inches

c) wellbore radius (rw) in feet

d) interval tested (*depth'*) to (*depth'*)

B) Recovery Data

a) Recovered fluid volume in the sampler in feet

b) Recovered fluid volume from the drill pipe in feet

1. oil gravity
2. water specific gravity
3. oil viscosity

C) Determine:

a) bottom-hole temperature in degrees Rankine

b) porosity height in feet

c) formation volume factor (B)

d) gas/oil ratio

2) Develop a matrix.

A) **Initial Flow**

delta t (min)	vs.	Pf (psi)
0		
5		
10		
15		
20		

B) **Initial Build-up** (t = time of the initial flow period)

delta t (min)	vs.	Pw (psi)	vs.	[t + delta t] ÷ delta t
0				
2				
4				
6				
8				
10				
12				
14				
16				
18				
20				

C) **Final Flow**

delta t (min)	vs.	Pf (psi)
0		
5		
10		
15		
20		

D) **Final Build-up** (t = time of the final flow period)

delta t (min)	vs.	Pw (psi)	vs.	[t + delta t] ÷ delta t
0				
2				
4				
6				
8				
10				
12				
14				
16				
18				
20				

3) Calculate the: [**C-**]

A) production rate.
B) flow capacity.
C) average effective permeability.
D) radius of investigation.
E) damage ratio.

j- Gas Test Procedure

1) Collect the information.

A) Well Data

a) drill pipe size in inches

b) drill collar size in inches

c) wellbore radius (rw) in feet

d) interval tested (*depth'*) to (*depth'*)

B) Recovery Data

a) gas production rate (Qg)

1. usually measured on a positive choke in MCF/D

C) Determine:

a) bottom-hole temperature in degrees Rankine

b) porosity height in feet

c) deviation factor (Z)

d) gas gravity

e) gas viscosity (u)

2) Develop a matrix.

A) **Initial Flow**

delta t (min)	vs.	Pf (psi)
0		
10		
20		
30		

B) **Initial Build-up** (t = time of the initial flow period)

delta t (min)	vs.	Pw (psi)	vs.	[t + delta t] ÷ delta t
0				
5				
10				
15				
20				
25				
30				
35				
40				
45				
50				
55				
60				

C) **Final Flow**

delta t (min)	vs.	Pf (psi)
0		
15		
30		

D) **Final Build-up** (t = time of the final flow period)

delta t (min)	vs.	Pw (psi)	vs.	[t + delta t] + delta t
0				
10				
20				
30				
40				
50				
60				
70				
80				
90				
100				
110				
120				
130				
140				
150				
160				
170				
180				

3) Calculate the: [C-]
   A) production rate through a positive choke (Qg).
   B) flow capacity.
   C) average effective permeability.
   D) radius of investigation.
   E) damage ratio.
   F) indicated flow rate.

k- Come Out of the Hole

1) The trip out of the hole is especially hazardous.
   A) Everyone should be very cautious.
2) Turn off lights and electrical equipment.
3) Carefully watch the pit level for signs of swabbing the zone in (i.e. - as pipe is pulled, the proper amount of mud must be returned to the hole).
   A) Designate one man to observe the mud level:
      a) during the test.
      b) while coming out of the hole.
4) Record the recovery times of each drill pipe section in order to estimate the recovered volumes of each DST fluid.
   A) salt water
   B) oil
   C) gas-cut mud
   D) etc.

C- INTERPRETATION OF THE DRILL STEM TEST

a- Recovered Fluid

1) Identify and record the relative amounts of each recovered fluid.
   A) water cushion
   B) formation oil
   C) formation gas
   D) formation water
   E) drilling mud
   F) ratio of:
      a) water to oil
      b) gas to oil
         1. formation volume factor or reservoir fluid

2) Calculate the production rate.

A) Oil

a) Read the final flowing pressure from the DST chart.

b) Calculate the hydrostatic head of the recovered fluid.

1. **[Chapter 7]**

c) Use either formula to approximate production in barrels per day.

1. Where:

Q	= production rate
bpd	= barrels per day (also BPD)
rec fld	= recovered fluid
Cp	= capacity of the pipe
min	= minutes
p1 to p2	= pressure interval in undisturbed portion of test
t1 to t2	= time interval in undisturbed portion of the test
hydro g	= hydrostatic gradient of fluid that entered during test

Qbpd = [# ft of rec fld x Cp bbls/ft x 1,440 min/day] ÷ 60

Qbpd = [(p2 - p1)psi x Cp bbls/ft x 1,440 min/day] ÷ [hydro g x (t2 - t1)min]

A. This is the more accurate of the two formulas.

B. If oil is the fluid that entered during the test, use 0.368 psi/ft as the hydrostatic gradient.

B) Gas

a) Gas flow rates can be estimated based on flow through a positive choke.

b) Choke coefficients: see **Volume 3, Chapter 31, D-**

c) An indication of the absolute open flow potential of a gas well can be estimated (e.g. - equation for 1 point on a 4-point test to calculate gas deliverability).

Indicated flow rate = [Qg x Pe] ÷ [$(Pe^2 - Pf^2)^{1/2}$]

1. Where:

Qg	= production rate of the gas
Pe	= extrapolated static reservoir pressure in psig
Pf	= final flowing pressure in psig

b- Interpretation

1) A qualitative analysis should yield information regarding:

A) formation condition.

B) formation pressure.

C) formation damage.

D) permeability.

E) permeability barriers.

F) flow capacity.

G) production rate.

H) depletion.

2) Pressure Build-up Curves

A) Initial Inflection

a) influenced by:

1. compressibility of the fluids
2. gasses in the wellbore

b) This information can sometimes be used to identify damage or stimulation candidates.

B) Curved Portion

a) Indicates the rate of build-up of the reservoir pressure in the area that was drained by the previous flow period.

b) The rate of build-up is influenced by:

1. reservoir pressure.
2. average effective permeability.
3. formation damage.

c) This part of the curve is an indication of reservoir conditions.

C) Straight-line Portion

a) an area where there is very little build-up

3) Plugging of Tools

A) indicated by sharp pressure fluctuations

B) normally occur during flow periods

4) Inconclusive Tests

A) caused by:

a) lost packer seat

b) drill pipe leaking

c) leaking tool in closed position

5) Pressure Analysis

A) The initial pressure of the second flow should equal the final pressure of the first flow.

B) The initial pressure should be equal to or greater than the final pressure for the same closed-in duration.

C) The Build-up Curves of a DST must be read in increments **(delta t)** and at their corresponding wellbore pressures (**Pw**).

a) Using the flow time (t) or the total productive time before the build-up, a plot should be made of **(t + delta t) ÷ delta t** on semi-log paper for each increment versus wellbore pressure.

b) All of these points will not fall on a straight line, therefore extrapolate in a straight line using the highest pressures as the most significant points.

c) The slope of this line is m.

d) Static reservoir pressure is the value where the line with the slope of m intersects (t + delta t) ÷ delta t = 1.

1. Where:

t = time interval of the flow period
delta t = time increment with a corresponding wellbore pressure increment of Pw

6) Permeability

A) Calculate the permeability of the formation.

Q = [kh x m] ÷ [162.6 x u x B]

a) Where:

Q = production rate
kh = flow capacity in millidarcy-feet
= average effective permeability height determined by:

Liquid:

kh = [162.6 x Q x u x B] ÷ m
Q = liquid flow rate in BPD
u = viscosity of the fluid in cp
B = formation volume factor
m = slope of the build-up in psi/cycle

Gas:

kh = [1,637 x Qg x Z x T x u] ÷ mg
Qg = gas flow rate in MCF/D
Z = deviation factor (usually ranges from 1 to 0.8)
T = temperature in degrees Rankine
u = viscosity of the gas in cp
mg = slope of the build-up in psi^2/cycle

m = slope of the extrapolated pressure plot minus liquid
u = viscosity in centipoise (cp)
B = formation volume factor (reservoir bbl per stocktank bbl)

B) A Build-up Curve in a high permeability zone:
  a) responds very quickly.
  b) has a 90° angle with the base line.
  c) does not start its curvature until the later development of the curve.

C) A Build-up Curve in a low permeability zone:
  a) responds poorly.
  b) will take some time to build-up to static pressure.

D) Average Effective Permeability

$k = kh \div h$

  a) Where:
    k = average effective permeability
    kh = calculated above
    h = determined from well data or core data

7) Formation Damage

A) indicated by:
  a) quick inflection similar to high permeability
  b) short radius curve
  c) flat remaining curve

B) Calculate the damage ratio.
  a) Liquid

$DR = 0.183 \times [(Po - Pf) \div m]$

  1. Where:
    DR = damage ratio
    Po = reservoir pressure
    Pf = final flowing pressure in psig
    m = slope of the build-up in psi/cycle

  b) Gas

$DR = [Pe^2 - Pf^2] \div [2 \times mg \times \log(0.47 \times [ri \div rw])]$

  1. Where:
    DR = damage ratio
    Pe = extrapolated static reservoir pressure in psig
    Pf = final flowing pressure in psig
    mg = slope of the build-up in psi^2/cycle
    ri = depth of fluid invasion in feet
      = radius of investigation = $[k \times t]^{1/2}$, t = days **or**
      = radius of investigation = $4.63 \times [k \times t]^{1/2}$
    rw = radius of the wellbore in feet

C) Damage Ratio Interpretation
  a) If - ≤ DR ≤ 1 = no damage
  b) If 1 ≤ DR ≤ 2 = moderate damage
  c) If 2 ≤ DR ≤ 5 = damage
  d) If 5 ≤ DR ≤ inf = severe damage

D) A damage ratio of 6 implies, theoretically, that the production could be improved six-fold if all of the damage could be removed.

E) Deep damage is suspected when the initial build-up pressure is lower than the final build-up pressure at the same duration.

8) Reservoir Depletion

A) A reservoir is depleted if it displays these characteristics:
  a) the first flow period must be long enough to relieve supercharge (surge pressure)
  b) a drop in pressure between the initial pressure build-up and the final pressure build-up.
  c) a decreasing rate of production in the second flow period

c- Evaluate the Results

1) Based on the recovery volumes, which are tabulated by the Testing Company, make a decision as to whether or not this zone will produce in commercial amounts.

11 - LOST CIRCULATION

TABLE OF CONTENTS

A- GENERAL

a- Action

1) Generally speaking, the deeper the casing is set the higher the mud weight can be raised without a loss of circulation.
2) Take immediate action once it is determined that circulation has been lost.
3) To regain control over the hole, pull out of the hole to a point above the loss/thief-zone where full circulation can be re-established.
   A) On occasion, induced fractures can heal by themselves if the following actions take place upon the loss of circulation.
      a) Pick up several stands above the loss-zone.
      b) Let the fluid level drop to static level.
      c) Turn off the pumps.
      d) Monitor the hole.
      e) Wait while the hole heals.
4) If full or partial returns cannot be obtained, evaluate the possible use of lower weight fluids.
   A) even consider using water

b- Materials Source

1) A good source for frac gradients is a local stimulation company.

B- LOCATING THE LOSS-ZONE

a- Lost Returns

1) When returns are lost with a long interval of uncased hole, the zone of loss is more likely to be near the last casing shoe than further downhole.
2) If drilling in an old field and returns are lost, the mud is probably being lost to a depleted zone.
3) If the loss occurs while drilling ahead in a normally pressured interval with no change in mud weight, the fluid will most likely be lost into a pre-existing void which the bit has just encountered.
4) If the loss occurs while going in the hole with pipe, it is safe to assume that a transient surge pressure has induced a fracture.
5) If the depth at which the loss occurs is not obvious, attempts should be made to determine it.
   A) This information is required if lost circulation material (LCM) is to be placed accurately and correctly.
   B) The hydrostatic pressure that the formation will stand is measured by the distance from the surface that a mud column of a given density falls before flow into the formation stops.
   C) This distance can be measured by counting the pump strokes required to fill the drill pipe.
      a) Make the required calculation from known capacity.

      barrel per stroke x number of strokes = number of barrels

      number barrels ÷ barrels per foot capacity = loss-zone depth

      depth x MW x 0.052 = tolerated hydrostatic pressure

b- Loss-Zone Surveys

1) Radioactive Tracer Survey
   A) very accurate but expensive
   B) requires the intentional loss of mud
   C) Use a low half-life material to minimize future gamma-ray logging distortion.
   D) Procedure
      a) Run a Gamma-Ray Log.
      b) Spot a slug of radioactive material above the suspected loss-zone.
         1. Squeeze into the formation.
      c) Run a second Gamma-Ray Log.
      d) The depth of loss will be recognized by a sudden increase in radioactivity.

2) Temperature Survey
   A) A Temperature Log is run to establish the gradient for the hole.
   B) A quantity of mud is pumped into the hole.
   C) A second Temperature Log is run.
   D) The zone of loss is identified by a dramatic temperature difference between the two surveys.

3) Hot Wire Survey
   A) An instrument containing a wire whose resistance varies with temperature is spotted in the hole.
      a) The resistance is measured.
   B) Mud is pumped into the hole.
      a) If the tool is below the zone of loss, the resistance will not change.
      b) If the tool is above the zone of loss:
         1. the wire will cool.
         2. the resistance will change.
   C) A large volume of mud can be pumped away by this method while making a careful determination of the depth of loss.

4) Transducer Survey
   A) A transducer is an instrument that detects movement of the mud downhole.
   B) Downward flow of the mud creates a pressure difference across a diaphragm which causes the transducer to transmit a signal to the surface through a cable which suspends the instrument downhole.

c- Prevention

1) To prevent lost circulation by marginal pressures:
   A) carry the lowest mud density possible.
   B) control solids.
      a) Excessive solids will result in higher equivalent circulating densities (ECDs).
      b) This condition may lead to loss of circulation.
   C) use the lowest circulation rates that can adequately clean the hole.
   D) adjust the rheological properties of the mud to give maximum hole cleaning properties with minimum pressure drop in the annulus.
   E) avoid drilling with a balled bit and drill collars.
   F) run pipe in the hole slowly.
   G) do not ream down rapidly (with pumps on).
   H) break circulation several times on the way in the hole.
   I) when back on bottom after a trip, break circulation slowly and raise the pipe while doing so.
   J) minimize gel strengths.

C- LOST CIRCULATION MATERIALS { 65 }

a- Classification

1) Fibers - effective for stopping loss in highly permeable formations
2) Flakes - effective for stopping loss in highly permeable formations
3) Granules - most effective for sealing fractures at high pressures
   A) The width of the fractures that can be sealed depends on the:
      a) concentration of the sealing material.
      b) type of sealing material.
4) Various mixtures of 1), 2), and 3)

b- Criteria for a General Purpose LCM

1) It should:
   A) contain high-strength granules with a definite size distribution.
   B) form a seal at both high and low differential pressures.
   C) be equally effective in sealing:
      a) unconsolidated formations.
      b) fractures or vugs in hard formations.

c- Sealant Concentration

1) The optimum concentration for sealing material under the most severe conditions is 30 - 40 pounds per barrel.

d- Common Methods Used to Combat Lost Circulation

1) High Filtrate Squeeze
   - A) depends upon tightly packed and dehydrated solids to create the required seal.
   - B) Ideal placement technique
     - a) Squeeze the slurry into the loss-zone.
     - b) Hold squeeze pressure for several hours before trying to circulate.
     - c) In many cases, no squeeze pressure will develop.
   - C) The volume of slurry to use for a given application may be 50 - 200 barrels, depending on the volume of uncased hole in the well.
     - a) The water can be fresh or salty.
     - b) Pilot test (take several samples) as the LCM is added to make sure that it maintains the kind of properties you want.
     - c) The table below makes one barrel.
       1. For example: if you want one barrel of squeeze material to weigh 10 pounds per gallon, add 50 pounds of sealant and 60 pounds of a weight material such as barite to 0.84 barrels of water.

High Water-Loss High-Solids Squeeze

pounds per gal	sealant (pound)	weight material (pound)	fresh water (barrel)
9	50	0	0.87
10	50	60	0.84
11	47	120	0.80
12	42	180	0.77
13	38	230	0.74
14	34	290	0.70
15	31	350	0.67
16	28	400	0.63
17	25	460	0.60
18	22	520	0.56
19	17	580	0.52

2) Gunk Squeeze
   - A) Diesel oil is used as a spacer between gunk and mud or water.
   - B) The diesel oil bentonite (DOB) or diesel oil bentonite cement (DOBC) slurry is pumped to the bottom of the drill pipe.
     - a) The drill pipe is placed somewhat above the loss-zone, or at the bottom of the last casing.
   - C) Rams are closed.
   - D) The gunk followed by water is squeezed into the formation; or mud is pumped from the drill pipe and the mixture is squeezed into the formation.
   - E) Various polymers can be substituted for part of the bentonite in the gunk formula.
     - a) helps enhance the:
       1. rubberiness of the gel
       2. breathability of the plug

Recommended Mixtures

Type of Plug	Ratio
Mud-DOB Systems	
water : DOB	1.2 : 1.00
10.2 ppg mud : DOB	1.0 : 1.20
17 ppg mud : DOB	2.0 : 1.00
saturated salt water : DOB	1.0 : 2.33
Mud-DOBC Systems	
water : DOBC	1.0 : 3.00
10.2 ppg mud : DOBC	1.0 : 1.86
17 ppg mud : DOBC	1.0 : 1.35

F) Where:
- DOB = diesel oil bentonite, prepared by adding 400 pounds of bentonite to 1 barrel of diesel oil
- DOBC = diesel oil bentonite cement, prepared by adding 200 pounds of bentonite and 200 pounds of cement to 1 barrel of diesel oil
- M-DOB = mud-diesel oil bentonite
- M-DOBC = mud-diesel oil bentonite cement

3) Mud Property Alteration

A) As long as it does not put control of the well at risk, try to lower the hydrostatic head of the mud by either:

a) aeration.

1. Run a "parasite string" of pipe next to the last string of casing above the loss-zone.
2. As the loss-zone is drilled, air is pumped through the tubing lightening the hydrostatic head of the mud above the loss-zone.
   - A. The tubing has a choke on bottom to:
     - a. maintain a constant volume of air.
     - b. reduce surging.
3. There are problems drilling with aerated mud.
   - A. It is difficult to keep in a steady state because:
     - a. the air tends to surge at the surface.
     - b. this surging varies the pressure on the wall of the hole.
   - B. It is difficult to tell exactly where the cuttings are coming from when the rig is drilling fast.
   - C. There are hostile gases that can react with the oxygen in the mud.
     - a. can damage the drill pipe

b) switching to a foam mud system.

1. Foam hydrostatic pressure is the equivalent of a fluid weight of roughly 1 - 3 pounds per gallon.
2. When hole conditions will permit the use of a drilling fluid in this density range, foam is an excellent fluid to use.
3. Some shale stabilization capability can be built into foam by using additives.
4. To make one barrel of shale drilling foam, combine all of the following materials together.

Shale Drilling Foam

water	0.75 barrel
caustic soda	0.25 pound
gel	7.50 pounds
KCL	10.50 pounds
surfactant	1.00 % by volume

4) Drilling with Air
   A) Sometimes the loss-zone can be drilled with air and subsequently cased off.
      a) Zones of this kind can often be drilled by "drilling blind" (pumping water down the drill pipe and drilling ahead without returns).
      b) Returns might be obtained after the loss-zone has been drilled.

D- LOST CIRCULATION CEMENT PLUG DESIGN

a- Basic Slurry Design

1) What is the bottom-hole circulating temperature (BHCT)?
   A) When the BHCT is lower than 200 degrees Fahrenheit, use low-temperature retarders.
   B) When the BHCT is higher than 200 degrees Fahrenheit, use regular retarders.
2) Designs
   A) Often, these slurries will contain gilsonite or other bridging agents to:
      a) divert cement to all areas of lost circulation.
      b) prevent over-displacement.
   B) Mixes

Cement Classes	slurry weight in ppg
Class C + 8%-15% gel (< 200°F BHCT)	11.00 - 13.0
Class H + 12%-25% gel	11.00 - 13.0
Thixotropic (light wt) (< 240°F BHCT)	12.95
Thixotropic (Class H) (< 240°F BHCT)	13.80 -14.9

3) Will the hole support the fluid?
   A) If no, go to 4).
   B) If yes, adjust the slurry density so that the hydrostatic pressure will not force all of the cement into the formation before the cement can gel.
4) Is the hole taking all fluids?
   A) If yes, use light weight thixotropic materials which gel quickly.
      a) definition: thixotropic [**Chapter 13, A-**]
   B) If the BHCT is too high, use Class H + gel with minimum thickening time.
5) Is the mud harmful to the cement?
   A) Incompatible mud retards cement and yields no support.
   B) Spacers should be used to insure a competent LCM plug, especially after drilling out.
   C) If high calcium muds are in use and the cement comes into contact with the mud, this reaction could cause a "flash set" (premature curing of cement in a place where it is not wanted).
6) Is water flow a problem?
   A) If yes, use thixotropic cement which will:
      a) resist contamination.
      b) gel quickly.
   B) Design the slurry for quick gelling.
   C) Reactive sodium/calcium chloride spacers form a semi-solid gel which helps to control water flow.

12 - DRILLING MUD

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A- COMPONENTS OF THE SYSTEM

a- Tank and Pit Layout

1) The following is an example of a typical heavy mud system (12.5+ ppg) showing the mud route of the system in order of flow.
    - A) Specific requirements and components will vary depending on the rig.
2) Steel Tank #1
    - A) double-decker shale shaker
        - a) solids fall to shale pit opposite the tank
    - B) sand trap
    - C) partition
3) Steel Tank #2
    - A) de-gasser welded on top of and in between tanks #1 and #2
    - B) divider
    - C) 700 gallons per minute (gpm) mud pump that circulates mud to the mud cleaner
    - D) mud cleaner welded on top of tank #2
        - a) eight 4" cones over a 2' x 6' shale shaker
        - b) solids fall to shale pit opposite the tank
4) Steel Tank #3
    - A) connected to tank #2 with a welded line
    - B) a pump (approximately 15 gpm) connected to a centrifuge cleaner (approximately 1,200 rpm) that separates 5 - 74 micron particles and barite
        - a) barite falls into the tank and stays with the system
        - b) effluent liquid and colloidal particles are dumped to the shale pit
5) The duck nest (a small pit or tank) contains a predetermined amount of heavy mud for emergency use.
    - A) connected to tank #3
6) Note:
    - A) The mud cleaner can be replaced by a de-sander and a de-silter.
    - B) The de-sander is made up of six 6" cones with a pump operating at 100 gpm.
    - C) The de-silter is made up of twelve 4" cones with a pump operating at 100 gpm.
        - a) Barite falls into the same size range as silt.
            - 1. It will also be separated from the whole mud.
        - b) De-silters are rarely used on weighted muds above 12.5 ppg.

B- INDIVIDUAL RESPONSIBILITIES

a- Derrickman

1) Maintain the pumps.
2) Mix the mud.
3) Maintain the mud-treating equipment.
4) Watch for well control indicators.

b- Driller

1) Watch for well control indicators.
2) Monitor the mud condition.
3) Ensure hourly treatments.
4) Ensure that the mud is:
    - A) mixed properly.
    - B) balanced.
    - C) in good condition for a trip.
5) Maintain an acceptable rate of penetration.
6) Ensure that the bit does not get plugged.
7) Ensure that hole sweeps are used.
8) Keep lost circulation from developing into larger problems.
9) Supervise the Derrickman.
10) Document all hole stability problems.
11) Ensure that accurate mud tests are conducted and recorded.
12) Inform the Toolpusher of all changes.

c- Toolpusher

1) Ensure that the mud program is carried out.
2) Ensure that the mud mixing equipment can support the mud program.
3) Maintain spare parts for the mud mixing equipment.
4) Supervise the rig crews.
5) Ensure that adequate water is on location.
6) Ensure that safe conditions exist on the rig.
7) Ensure that regulations are followed.
8) Ensure that good drilling practices are followed.
9) Coordinate the mud treatments with other drilling operations.
10) Monitor the effects of the drilling operation on the mud program.
11) Make correlations between the mud treatments and downhole problems.
12) Ensure that operating policies are followed.

d- Drilling Foreman

1) Ensure accurate reporting.
2) Supervise.
3) Coordinate the actions of the service companies.
4) Accurately diagnose any problems.

e- Mud Engineer

1) Carry out the mud program.

f- Drilling Engineer

1) Keep solids under control.
2) Accurately diagnose any problems.
3) Perform accurate mud testing and reporting.
4) Properly mix the chemicals.
5) Use water properly.
6) Ensure the use of sweeps in unweighted, low-viscosity muds.
7) Keep the mud program simple.
8) Recognize the relationship among the:
   A) downhole conditions.
   B) hole stability.
   C) rate of penetration.
9) Correlate hole progress with offset wells.

C- SIZING THE SHAKER SCREENS

a- General

1) Run a coarse screen above the fine screen.
2) Run screens that are as fine as is possible.

	Screen Mesh Size	Micron Size Separated
First Shaker		
	20	836
	30	533
	50	280
	80	177
	100	140
Second Shaker		
	150	105
	200	74
	250	63

D- RECOMMENDED APPLICATIONS { 66 }

a- Legend

dis = dispersed mud system
non-dis = non-dispersed mud system
obm = oil-base mud
XX = definitely recommended
X = special application

b- Unweighted Muds (8.3 to 10.5 ppg)

	dis	non-dis	obm
fine screen shaker	XX	XX	XX
de-sander	XX	XX	X
de-silter	XX	XX	X
mud cleaner		X	X
centrifuge	X	X	X

c- Light to Medium Weight Muds (10.5 to 16 ppg)

	dis	non-dis	obm
fine screen shaker	XX	XX	XX
de-sander			
de-silter			
mud cleaner	XX	XX	XX
centrifuge	XX	XX	X

d- Weighted Muds

	dis	non-dis	obm
fine screen shaker	XX	XX	XX
de-sander			
de-silter			
mud cleaner	XX	XX	XX
centrifuge	XX	XX	X

e- Notes

1) Fine-Screened Shakers
   - A) Recommended Uses
     - a) all types and weight ranges of mud where it is desirable to mechanically remove the drill solids
   - B) Screen selection is frequently based on past experience.
     - a) If the mesh screen sizes are too small, mud can be lost over the shaker.
   - C) Screen mesh is defined as the number of openings per linear inch measured from the center of a wire.
     - a) A 70 x 30 oblong mesh screen (rectangular opening) will have 70 openings along a 1" line one way and 30 openings along a 1" line perpendicular.
     - b) A 30 x 30 mesh screen (square opening) has 30 openings along a 1" line in both directions.
     - c) Attempts are often made to group both types into the same class.
       1. For example: a screen might be referred to as an "oblong 80" in an attempt to rate the effective appature of a rectangle in terms of a square equivalent.
       2. This is not a true mesh count.
   - D) The selection of screen sizes depends on conditions at the location.
     - a) If the volume being circulated exceeds the capacity of the screens being used (i.e. - mud loss over the screens), another combination should be tried.
     - b) The shale shaker is the first line of defense against solids build-up in the mud.

2) De-sanders
   A) Recommended Uses
      a) unweighted muds having a low-cost liquid phase
   B) Special Application
      a) unweighted, non-dispersed and oil-base mud with a decanting centrifuge to reclaim liquid normally lost in de-sander underflow
   C) De-silters are used the same way.

3) Mud Cleaners
   A) Recommended Uses
      a) processing both water- and oil-base mud, light to medium weight
      b) controlling drill solids in weighted oil-base mud
   B) Special Application
      a) unweighted muds for minimum liquid discharge to the sump

4) Centrifuge
   A) Recommended Uses
      a) unweighted muds
         1. recovery of liquid phase
         2. removal of ultra-fine drill solids
      b) light to weighted muds (11 ppg)
         1. control of drill solids
         2. recovery of barite
         3. reduces dilution requirements
   B) Special Application
      a) recovery of valuable liquid from de-sander and de-silter underflow

E- TYPES OF DRILLING MUD SYSTEMS { 66 }

a- Oil-base

1) General
   A) Oil-base mud is a special type of drilling fluid.
      a) continuous phase - oil
      b) dispersed phase - water
   B) Oil-base mud contains:
      a) emulsifiers.
      b) wetting agents.
      c) lime.
      d) salt - sodium or calcium chloride added in the form of field salt water or brine water to protect the formation.
      e) sometimes clays.
      f) Lime, silicates and phosphate may also be present.
   C) Applications
      a) high temperatures
      b) deep holes
      c) problems with:
         1. sticking
         2. hole stabilization

2) True Oil-Base Systems
   A) differentiated from invert emulsion muds by the:
      a) amounts of water used
      b) method of controlling viscosity
      c) method of controlling thixotropic properties
      d) wall-building material
      e) fluid loss (2% to 5% water)
   B) usually a mixture of:
      a) oxidized asphalts
      b) organic acids
      c) alkalies or other agents
      d) diesel fuel

C) Viscosity and gelling properties can be maintained by adjusting the:
  a) acid concentration.
  b) alkali soaps.
  c) diesel fuel.

3) Invert Emulsion Systems
  A) An invert emulsion is a water-in-oil emulsion.
    a) continuous phase - diesel, crude, or some other oil
    b) dispersed phase - fresh or salt water
  B) Viscosity is:
    a) increased by water.
      1. 3% to 15% water but can range as high as 50%
    b) reduced by oil.
  C) To control rheological and electrical stability, adjust the:
    a) emulsifiers.
      1. fatty acids
      2. amine derivatives
    b) high molecular weight soap.
    c) water concentrations.

b- Water-base

1) Non-dispersed (non-inhibitive) Muds
  A) General
    a) usually consists of:
      1. "spud" muds
      2. natural muds
      3. other lightly treated systems
    b) used in:
      1. shallow wells
      2. top hole applications
    c) Maintain a drilled solids to bentonite ratio of 2 : 1.
      1. maximum acceptable ratio is 3 : 1
  B) Types
    a) Fresh Water
    b) Phosphate
    c) Low Solids

2) Dispersed (inhibitive) Muds
  A) General
    a) a drilling fluid having an aqueous phase with a chemical composition that tends to retard and even prevent (inhibit) appreciable hydration (swelling) or dispersion of formation clays and shales through chemical and/or physical means
    b) generally used where hole conditions may be hostile
    c) Inhibitors
      1. substances generally regarded as drilling mud contaminants
        A. salt
        B. calcium sulfate
      2. purposely added to mud so that the filtrate from the drilling fluid will prevent or retard the hydration of formation clays and shales
    d) Maintain a drilled solids to bentonite ratio of 3 : 1.
      1. maximum acceptable ratio is 4 : 1

  B) Ionic Activity
    a) General
      1. Acids, bases, and salts (electrolytes), when dissolved in certain solvents, especially water, are more or less disassociated into electrically charged ions or parts of the molecules, due to loss or gain of one or more electrons.
        A. Electron loss results in a positively charged cation.
        B. Electron gain results in a negatively charged anion.

C. The valence of an ion is equal to the number of charges it bears.

b) Ammonium Muds

c) Calcium Muds

1. Calcium treated muds (lime or gypsum muds) are drilling fluids to which quantities of soluble calcium compounds have been added or allowed to remain from the formation drilled, in order to impart special properties.
   A. When di-valent cations are added to a mud, they inhibit the swelling of formation clays and shales.
2. Muds with high levels of soluble calcium are used to:
   A. control sloughing shale and hole enlargement.
   B. prevent formation damage.
3. Main Ingredients of Calcium Systems
   A. calcium sulfate (hydrated lime gypsum)
   B. calcium chloride
4. Properties of Calcium Muds
   A. Gyp-Systems
      a. pH - 9.5 to 10.5
      b. excess gyp concentration of 2 to 4 pounds per barrel of 600 to 1,200 milligram per liter calcium
   B. Low Lime Systems
      a. pH - 11.5 to 12
      b. excess lime concentration of 1 to 2 pounds per barrel
   C. High (excess) Lime Systems
      a. pH - above 12
      b. excess lime concentration of 5 to 15 pounds per barrel

d) Salt Muds

1. a drilling fluid containing dissolved salt (brackish to saturated)
   A. may also include:
      a. native solids
      b. oil
      c. commercial additives
         1] clays, starch, etc.

e) Potassium Muds

C) Encapsulation

a) General

1. Through the use of encapsulators, drill solids are removed to the surface in a drier and firmer condition.
   A. increases the chances for removing them from the circulating system before they become soft, plastic, and dispersed as fines

b) Polymers

1. fluids formed by the union of two or more molecules of the same kind linked end to end into another compound having the same elements in the same proportion but a higher molecular weight and different physical properties
   A. e.g. - paraformaldehyde
2. effective in:
   A. flocculating muds (increasing gel strength)
   B. increasing viscosity
   C. reducing filtrate loss
   D. stabilizing the formation
3. Types Available
   A. Bentonite extenders
      a. higher acid solubilities than bentonites
      b. reduces the amount of clay needed to maintain viscosity
   B. Bio-polymers (cross-linked)
      a. good shear-thinning properties at low concentration

c) Lignosulfonates
   1. organic drilling fluid additives derived from the by-products of coniferous woods in the sulfite paper manufacturing process
   2. Uses of Common Salts
      A. as universal dispersants
         a. ferrochrome
         b. chrome
         c. calcium
         d. sodium
      B. for fluid-loss control and shale inhibition
         a. ferrochrome and chrome in large quantities
      C. selectively for calcium-treated systems
         a. other common salts

c- Dry Air

1) Dry air (or gas) is injected into the wellbore at rates capable of achieving annular velocities that will remove cuttings.

d- Mist

1) Foaming agents:
   A) are injected into the air stream.
   B) are mixed with the produced water.
   C) separate and lift drilled cuttings.

e- Stable Foam

1) Chemical detergents and polymers, and a foam generator are used to carry cuttings in a fast moving air stream.

f- Aerated Fluids

1) Air-injected mud (which reduces hydrostatic head) removes drilled solids from the wellbore.

g- Switching Mud Systems during a Job

1) Extra Costs of Oil-base Mud over Water-base Mud
   A) More mud handling equipment is required.
      a) matting on the rig floor to protect roughnecks from injury due to slips and falls
      b) pan under the rig floor to catch spilled oil-base mud
      c) canvas tarps over the rig tanks (open top) to keep out the rain
      d) storage tanks
      e) inside drill pipe wipers
      f) skimmers for the reserve pit to put by-passed oil through the separators
      g) kelly valve back-up
   B) Trucking to and from the location.
   C) Mud loss replacement on a per barrel basis.
   D) Effects of oil-base mud on the Operator's ability to evaluate the producability of potential zones of interest.
      a) all cores will look productive
      b) oddball invasion profiles on the Induction Curves
      c) no Spontaneous Potential (SP) Curve
      d) formation tests are usually the best means of evaluation
   E) Oil-base muds:
      a) should improve penetration rates.
      b) tend to decrease the chances of getting differential stuck.
      c) make mud property maintenance easier to accomplish.
      d) make it more difficult to drill a straight hole.
      e) are very expensive to clean up after the job is finished.
   F) The negative attitude of roughnecks towards working with oil-base muds will have an impact on their job performance.

F- TYPICAL ADDITIVES AND THEIR FUNCTIONS { 67 }

a- pH Control

1) include:
   A) lime
   B) caustic soda
   C) bicarbonate of soda

b- Bactericides

1) reduce the bacteria count
2) include:
   A) paraformaldehyde
   B) caustic soda
   C) lime
   D) starch preservatives

c- Calcium Remover

1) consists of:
   A) caustic soda
   B) soda ash
   C) bicarbonate of soda
   D) certain polyphosphates

d- Corrosion Inhibitors

1) usually include:
   A) hydrated lime
   B) amine salts

e- De-foamers

1) usually required in:
   A) brackish mud
   B) salt water mud

f- Emulsifiers

1) create a heterogeneous mixture of two fluids
2) include:
   A) modified lignosulfonates
   B) some surfactants
   C) anionic and non-ionic (negatively charged) additives

g- Filtrate Reducers

1) consist of:
   A) bentonite clays
   B) sodium carboxymethylcellulose (CMC)
2) prevent the measurement of the tendency of a liquid phase of the drilling fluid to pass into the formation

h- Flocculants

1) used to raise gel strengths
2) In order to make colloidal particles in suspension to group and settle out as solids, use:
   A) salt (brine)
   B) hydrated lime
   C) gypsum
   D) sodium tetraphosphates

I- Foaming Agents

1) can also act as surfactants that foam in the presence of water
2) permit air or gas drilling through water-bearing zones

j- Lubricants

1) designed to reduce torque and increase horsepower at the bit by reducing the coefficient of friction

k- Surface Acting Agents

1) called surfactants
2) reduce the interfacial tension between contacting surfaces
   A) water/oil
   B) water/solid
   C) water/air
   D) etc.
3) depending on the surfaces involved, are sometimes used as:
   A) emulsifiers
   B) de-emulsifiers
   C) flocculants
   D) de-flocculants

G- TROUBLE-SHOOTING WATER-BASE MUDS { 68 }

a- Rules of Thumb for Water-base Muds

1) Funnel Viscosity

   Funnel Viscosity = 4 x MWppg

   Funnel Viscosity = 4 x [(MWlbs/ft³) ÷ 2]

2) Add 1 or 2 sacks of gel for every 100 feet drilled.
3) The differential in funnel viscosity should be:
   A) no more than 10 seconds between pump suction and flowline.
   B) 20 seconds above normal (off bottom) after trips.
4) Add 1 or 2 sacks of gel for each hour a centrifuge is operating on an active mud system.
   A) The centrifuge separates out the fine drilled solids.

b- Problems, Indications and Treatments

PROBLEM	INDICATION	TREATMENT
Foaming	foam on surface of pits; reduced mud weights; reduced pump pressure or hammering pumps	Sprinkle pits with a fine spray of water or diesel. Add surface acting agents to the mud. Aluminum stearate is sometimes used for this.
Cement	high viscosity; high gel strengths; increases in pH, fluid loss, filtrate calcium	Remove with sodium bicarbonate. For large concentrations, convert to a mud system that will tolerate high cement. If the pH is greater than 12, use spersene.
Gypsum or Anhydrite Contamination (or Calcium)	high viscosity; high flash gels; or increased fluid loss, filtrate calcium and sulfate	Remove with soda ash.
Evaporite or Salt Domes	high viscosity; high flash gels; increase in fluid loss and salt content; grainy look to mud	Chemically alter mud properties using fluid loss control and additives. Might have to change out the mud system.

PROBLEM	INDICATION	TREATMENT
High Temperature Gelation	difficult to break circulation, or get back to bottom; high viscosity and gels off bottom; a decrease in alkalinity and an increase in fluid loss	Reduce solids and dilute the mud. Break circulation before reaching bottom. Treat with sodium chromate and thinners. Treat calcium to lower levels.
Corrosion	pitted drill pipe	Adjust pH to 11 - 11.5. Add 1 lb/bbl sodium chromate. Sometimes the pH can be raised by just adding lime. Most common method today is by adding corrosion inhibitors to the system. It is also cheaper.
Bit Balling	little or no progress in drilling and swabbing on trips	Maintain low viscosity and gel strengths to keep the hole clean. Clean the hydraulics system. Consider changing to a center-jet bit. Add oil.
Locked Cones	cones locked or bearing loose with structure still on cones	Reduce drilled solids and add lubricant.
Abrasion	premature bit failure and excessive wear of swabs, liners, and valve seats	Use a de-sander to get sand content down to minimum levels.
High Fluid Loss	soft, spongy filtercake that is too thick	If you feel that enough fluid loss additives have been used, add bentonite to the system. Run methylene blue test. Water loss tests should be run at BHT. A change of 10% at BHT is not usually acceptable. In areas with high BHT, this is difficult and expensive to achieve.
Salt Water Flow	pit gain; flow when shut down pumps; increase in chlorides; increase in total hardness; increase in flowline temperatures	Shut well in. Go through kill sheet. Adjust mud properties as required. Watch for large chloride increase.
Gas Kick	pit gain; flow when shut down pumps. gas-cut mud prior to the pit gain?	Shut well in. Go through kill sheet.

PROBLEM	INDICATION	TREATMENT
Mud Loss	decrease in pit volume or loss of returns	Lower mud weight and the ECD (equivalent circulating density).
Unstable Mud	barite settles out	Increase the viscosity and yield point (yp).
Increased Weight of Surface Mud	high viscosity	Incorporate mechanical solids removal equipment. Add water.
Carbonate or Bicarbonate Contamination		Add lime or gypsum.
High Viscosity	high funnel viscosity; high plastic viscosity; normal yield point; normal gels. high solids	Add solids removal equipment to remove drilled solids and fine barite particles. Add water to the system, and use a thinner as required.
	same as above but normal plastic viscosity, high yield point, high gels and normal solids	Same as above but add dispersants and check for contaminants like chlorides, calcium, or carbon dioxide.
	same as above but high plastic viscosity, high yield point, normal gels, and normal solids	Same as the second one above.
	high viscosity mud that does not take fluid loss control agents	Prepare a batch of new mud with excess fluid loss agents and add to mud over one circulation.
Penetration Rate	slow drilling with a new bit	In order: Change hydraulics. Change bit type. Change weight on bit. Change rotation speed. Remove solids. Lower the mud weight. Increase viscosity.
High pH	pH above 10	No treatment required. Sodium Bicarbonate will lower pH if necessary. Lignite and lignosulfonates have a pH less than 5, so they will also lower the pH.

PROBLEM	INDICATION	TREATMENT
Low pH	pH less than 7	Add caustic soda if low pH is a result of salt water flow.
Sloughing Shale	excessive cuttings over the shale shaker with very tight connections	Increase the mud weight, reduce fluid loss, increase viscosity, reduce drill pipe whipping, and reduce pressure surges. If the shale is bentonitic, no viscosity increase is necessary.
Plastic Salt	tight connections; have to ream to bottom after trips	Increase the mud weight. Ream through the tight spot.
	stuck pipe when fluid is saturated water-base or oil-base	Spot fresh water to dissolve where pipe is stuck, usually near the bit, then increase the mud weight.
Excess Filter Cake	differential sticking	Reduce filtration.

H- BOREHOLE INSTABILITY { 68 }

a- General

1) Borehole stability is directly proportional to mud weight.
2) Borehole instability is directly related to:
   A) exposure time.
   B) drilling fluid reactivity.
   C) water loss.
   D) viscosity.
   E) pH.

b- Purpose of Borehole Stability

1) A gauge hole can be cleaned with a low viscosity mud.
2) When this is done, drilling progress is rapid.
3) When drilling progress is rapid in normal pressure regimes, problems are few.

c- Disadvantages of an Enlarged Borehole

1) Mud viscosity and mud gel strengths will have to be raised in order to properly clean the hole.
2) Increasing these mud properties will:
   A) slow the penetration rate.
   B) increase the swab and surge pressures.
   C) increase gas-cutting of the mud.
3) If viscosity and gels have to be altered to raise the YP/PV ratio, lower the plastic viscosity instead of increasing the yield point.
   A) The best way to maintain low plastic viscosity (PV) is to:
      a) remove the drilled solids.
      b) keep the yield point no higher than required to provide adequate carrying capacity.
   B) Control the yield point (YP) by:
      a) adding (or withholding) thinners when drilling colloidal clays.
      b) adding bentonite when drilling in other formations.

d- Preventing Borehole Instability

1) Keep the ionic activity of the water in the mud equal to the in-situ ionic activity of the water in the shale.
2) Use low-solid or non-dispersed mud.
   A) These muds depend on:
      a) polymers.
      b) soluble salts.
      c) extensive use of mechanical solids removal equipment.
3) Normally, thinners are kept out of the mud system.
4) The pH of the mud system is kept low.
5) The small size of the potassium ion enables it to fit into the holes in the silica sheet on the surface of the clay platelet, which allows the platelet to be strongly bonded by the attractive forces.
6) Drill straight holes.
7) Keep pipe tripping speeds slow.
8) Keep the hydraulics such that fluid velocity in the annulus will not cause hole enlargement through erosion.
   A) Hole erosion will be more severe if the mud is in turbulent flow.
9) Other factors that affect borehole stability are:
   A) tectonic stress.
   B) pore pressure.
   C) formation dips.
   D) degree of compaction.

I- TROUBLE SHOOTING OIL-BASE MUDS {68}

a- Problems, Indications and Treatments

PROBLEM	INDICATION	TREATMENT
High Viscosity, with Water Contamination	high viscosity; weight reduction; change in the oil/water ratio. reduction in filtrate loss	Add oil, emulsifiers and lime.
High Viscosity, High Solids Content	retort analysis. increase in viscosity and plastic viscosity after long periods of drilling with a diamond bit.	Reduce shaker screen size on shaker and mud cleaner. De-sander is used only if a centrifuge is available to run on the effluent (to reclaim oil). Note that a mud cleaner is more effective at doing this.
High Viscosity, Low Temperature	long periods of inactivity in the surface pits	Heat the sample to the recommended temperature for the appropriate tests.
Low Viscosity with lack of Gels	reduction in mud weight; little or no cuttings at surface; have to wash to bottom after trips; barite settling in mud check samples; reduction in yield point and gel strength	Add gel/clay, saturated salt water if oil/water ratio is too high, and quicklime for concentrates.
High Filtrates with Low Emulsifiers	water in filtrate, low voltage breakdown (vb) and inability to emulsify additional water	Add concentrates and lime to tighten emulsion. If filtrate loss is still high, add resin.

PROBLEM	INDICATION	TREATMENT
High Filtrates with High Temperature	high filtrate values despite correct concentration of chemicals	Add resin.
Emulsion Breaking with Low Concentration of Emulsifiers	water in filtrate, low voltage breakdown (vb), and an inability to emulsify additional water properly	Add concentrate with proper amounts of lime.
Oil Separation, and lack of Proper Agitation on Mix	oil begins to separate and come to the surface when at rest	Provide sufficient agitation.
Water-Wet Solids	dull graying of mud. barite flocculations may be seen on sand content test.	Add lime and wetting agent.
Barite Settling	low yield strength	Add concentrate, gel/clay, and maybe change oil/water ratio.
Reduction in Electrical Stability	decline in voltage breakdown	Agitate vigorously and possibly add an emulsifier.
Salt Formations	free salt across shaker (voltage breakdown may be reduced as free salt is carried as a solid)	If voltage breakdown drops, use high temperature - high pressure fluid loss as the main indication of emulsion stability.

J- SPECIFIC GRAVITY AND BULK DENSITY OF MUD MATERIALS { 66, 69 }

Material	**Specific Gravity**	**Bulk Density of Sacked Material (lb/ft^3)**
attapulgite	2.50 - 2.70	60
barite	4.20 - 4.40	135
bentonite	2.50 - 2.70	60
cement: Classes A,B,C,D,E,G	3.15	96
diesel oil	0.84	-
lignite	1.60	30 - 35
lignosulfonate	1.50	35
lime	2.30 - 2.40	31
mica	2.60 - 3.20	25
quartz sand	2.65	100
salt ($NaCl$)	2.16	71
salt ($NaCl_2$)	2.15	50 - 55
(sodium) CMC	1.60	40
soda ash	1.55	58
starch	1.50	15 - 20
walnut shells	1.28	48
water	1.00	-

K- SELECTION OF DRILLING FLUIDS {68}

a- Properties that Affect the Penetration Rate

1) Density
   A) most important
2) Viscosity
   A) the lower this number, the faster the drilling
3) Solids content
   A) leads to fast drilling when low, while maintaining optimum solids content (the minimum solids content required to provide the desired mud properties)
   B) To keep solids low:
      a) separate them at the surface by keeping the viscosity close to that of water and a low yield point.
         1. Viscosity values that are too low can cause loss of hole cleaning.
         2. Keep viscosity between 35 and 40 and clean at the surface.
      b) add flocculants (either soluble salts or organic flocculant) to enhance solid separation.
      c) use adequate facilities for separating solids at the surface.
         1. shale shakers
         2. de-sanders
         3. de-silters
         4. properly baffled earth pits
      d) use a non-viscous additive such as calcium lignosulfonate when filtration control is important.
      e) use soluble salts to increase density when necessary.
         1. Barite is in the bridging range because of its size.
      f) select a polymer for its ability to maintain hole stability if caving shales are expected to be exposed in the hole.
         1. Once a hole enlarges:
            A. a viscosifier is needed for hole cleaning purposes.
            B. the required solids content cannot usually be maintained.
4) Use of low-solid polymer muds
5) Use of additives that inhibit bit balling in gummy shales

b- Selection of Mud Types

CLASSIFICATION	PRINCIPLE INGREDIENTS	CHARACTERISTICS
Dry Air	dry air	Fast drilling in dry, hard rock. No water influx. Dust.
Mist	air, water, mud	Wet formations but little water influx. High annular velocity.
Foam	air, water, foaming agent	Stable rock.
Stable Foam	air, water, polymers	All low pressure conditions. Large volumes of water. Big cuttings removed at low annular velocities. Polymer selection should afford hole stability and tolerate salts. Foam can be formed at the surface.

CLASSIFICATION	PRINCIPLE INGREDIENTS	CHARACTERISTICS
Fresh Water	fresh water	Fast drilling in stable formations. Need a large settling area or ample water supply and easy disposal.
Salt Water	sea water	Brines for density increase. Limited to low permeability formations.
Low-Solids Muds	fresh water, polymer	Fast drilling in competent zones. Mechanical solids removal equipment required. Contaminated by cement and soluble salts.
Spud Mud	bentonite, water	Inexpensive.
Salt Water Muds	sea water, brine, starch, cellulosic polymers	Drill rock salt. Workovers. Drilling salts other than halite may require special treatment.
Lime Muds	fresh or brackish water, lime, lignite	Shale drilling. Simple maintenance at medium weights. Maximum temperature 300°F with lignite added.
	lignite, sodium-chromate, surfactant	Some tolerance for salt. Unaffected by anhydrite or cement with a pH in the 11-12 range.
Gypsum Muds	same as lime muds but use gyp for lime	Same as lime muds, but maximum temperature 324°F. Unaffected by salt. (pH 9 - 10)
CL-CLS Muds (chrome lignite, chrome ligno-sulfonate)	fresh or brackish water, bentonite, caustic soda, chrome lignite. surfactant added for high temperatures	Shale drilling. Simple maintenance. Maximum temperature 350°F. Same tolerance for contaminants as gypsum muds. (pH 9 - 10)
Potassium Muds	potassium chloride, actylic, polymer, bentonite. lignite KOH, Drispac. de-foamer	Hole stability. Mechanical solids removal equipment required. Fast drilling with minimum solids content. (pH 7 - 8)

CLASSIFICATION	PRINCIPLE INGREDIENTS	CHARACTERISTICS
Oil	weathered crude oil	Low pressure well. Completion and workover.
	asphaltic crude; soap, water	Drill shallow, low pressure zones. Water is used to increase density and cuttings carrying ability.
Asphaltic Muds	diesel oil, asphalt, emulsifiers, water (2% - 10%)	Composition designed for any density and hole stabilization requirements and temperature requirements to 600°F.
Non-Asphaltic Muds (invert muds)	diesel oil, emulsifiers, olephilic clay, modified resins and soaps, water (5% - 40%)	High initial costs and environmental restrictions. Low maintenance costs.

13 - CEMENT SLURRY DESIGN

TABLE OF CONTENTS

A- GENERAL

a- Definitions

Cement - the product obtained by grinding clinker, consisting of hydraulic calcium silicates, to which no additions, other than suitable set-modifying agents (defined by API), have been interground or blended during manufacture. Applies to the cement classes defined below.

Thixotropic Cement Slurry - specially formulated so that the slurry flows easily (low viscosity) while being pumped during mixing and displacement. However, when pumping stops or the slurry becomes static, a rapid setting takes place (i.e. - viscosity increases quickly when static).

b- Mandatory Requirements

1) Cements should comply with the mandatory requirements of the API RP 10B.
   A) current edition and current supplement

c- Testing {70}

1) Lab test the selected slurries prior to pumping them.
   A) This is critical in casing and liner cementing.
2) Lab tests should be conducted in a high-pressure, high-temperature consistometer where the slurry will be exposed to downhole temperatures and pressures.
3) Accurate bottom-hole circulating temperatures (BHCTs):
   A) are critical.
   B) can be obtained from (in order of importance):
      a) well logs.
      b) measured temperatures during circulation surveys conducted prior to cementing.
      c) local knowledge.
4) Cement is tested for:
   A) sampling procedures.
   B) free water.
   C) compressive strength.
   D) soundness.
   E) fineness.
   F) thickening time.

B- ADDITIVES {71}

a- Bentonite

1) Advantages
   A) lightweight, high-volume slurries possible
   B) early compressive strengths
   C) some fluid-loss control
   D) helps transport cement solids
   E) compatible with all additives
   F) wide weight range
   G) very economical
2) Limitations
   A) low compressive strengths

b- Calcium Chloride

1) Advantages
   A) reliable acceleration of hardening and thickening time
      a) saves rig time
   B) increased heat of hydration of cement to aid temperature surveys
   C) economical
   D) no extra water required

2) Limitations
   - A) chloride ion detrimental to most fluid-loss additives
   - B) concentrations above 2% can cause "flash setting" of cement
   - C) $CaCl_2$ is hygroscopic and difficult to handle

c- Cellophane

1) Advantages
   - A) high strength when wet
   - B) no effect on thickening time or compressive strength
   - C) no water requirements
2) Limitations
   - A) over 2 pounds per sack causes equipment problems

d- Diacel A

1) Advantages
   - A) reliable acceleration of both:
     - a) thickening times
     - b) thickening times and compressive strengths
   - B) no detrimental effect on fluid loss
   - C) no extra water requirement
2) Limitations
   - A) only used with fluid-loss additives
   - B) concentrations above 7% deteriorate fluid-loss control
   - C) more expensive than other accelerators

e- Diacel D

1) Advantages
   - A) high yield
   - B) not detrimental to other additives
   - C) economical
2) Limitations
   - A) low strength

f- Dispersants

1) Advantages
   - A) lower slurry viscosity
   - B) lower frictional pressure
   - C) allows slurries to be mixed to 18 pounds per gallon
   - D) aids mud removal
   - E) retards slurries at temperatures up to 200°F BHCT
   - F) increases effectiveness of retarders and fluid-loss additives
   - G) increases compressive strengths
   - H) helps control fluid loss
2) Limitations
   - A) excessive amounts cause severe settling
   - B) increases viscosity when used with high concentrations of salt

g- Fluid-Loss Additives

1) Advantages
   - A) helps prevent lost circulation and stuck pipe by minimizing cement dehydration in the annulus
   - B) minimizes gas-cutting of cement
   - C) provides excellent bonding qualities to both pipe and formation
   - D) minimizes formation damage from slurry filtrate
2) Limitations
   - A) high slurry viscosity at concentrations above 0.7%
   - B) to be used very cautiously with salt
   - C) degrades at high temperatures

h- Gilsonite

1) Advantages
   - A) replaces water to reduce density
   - B) easily supported by slurry due to its low specific gravity
   - C) graded grain size acts as an excellent bridging material
   - D) up to 50 pounds per sack may be used with the addition of bentonite
2) Limitations
   - A) expensive as an extender
   - B) should not be used above 220°F BHCT

i- Lignosulfonate

1) Advantages
   - A) predictable retardation and compressive strength development
   - B) effective in combination with dispersants
   - C) no extra water required
2) Limitations
   - A) very little dispersant effect by itself
   - B) not designed for high gel cement systems
   - C) minor detrimental effect on fluid-loss additives

j- Metasilicate

1) Advantages
   - A) very lightweight, high-yield slurries possible
   - B) early compressive strengths
   - C) economical
   - D) low free water at high water ratios
2) Limitations
   - A) low compressive strength
   - B) not compatible with most slurry additives
   - C) limited temperature range

k- Salt

1) Advantages
   - A) retards or accelerates cement slurries, depending on concentration
     - a) accelerates at low percent concentrations
     - b) retards at high percent concentrations
   - B) improves bonding properties
   - C) causes cement expansion in high concentrations
   - D) protects formations
   - E) helps prevent washout of salt zones
   - F) helps prevent shale sloughing
   - G) promotes early compressive strength development
   - H) enhances retarder effectiveness
   - I) lowers frictional pressures
   - J) helps densify slurries
2) Limitations
   - A) detrimental to fluid-loss additives and some dispersants

l- Ground Walnut Shells

1) Advantages
   - A) helps bridge lost circulation zones
   - B) no appreciable effect on thickening time or compressive strength
2) Limitations
   - A) needs extra water in some slurries
   - B) concentrations above 4 pounds per sack cause problems with downhole equipment

m- Effects of Additives on Physical Properties

1) Where:

Dec	= decrease
Inc	= increase
Les	= less
Mor	= more
Acc	= accelerate
Rtd	= retard
Dia Earth	= Diatomaceous Earth
Lignosulf	= Lignosulfonate
LWLca	= low water loss chemical additive
LCM	= lost circulation material
X	= major effect and/or principle purpose for which used
o	= minor effect

	Density		Water Required		Viscosity		Thickening Time	
	Dec	Inc	Les	Mor	Dec	Inc	Acc	Rtd
Bentonite	X			X		o	o	
Perlite	X			o		o		
Dia Earth	X			X		o		o
Pozzolan	X			o		o		
Sand		X		o		o		
Barite		X		o		o		
Hematite		X				o	X	
CaCl					o		X	
NaCl		o						o
Lignosulf					X			X
Diesel								o
LWLca								o
LCM				o		o		

	Early Strength		Final Strength		Durability		Water Loss	
	Dec	Inc	Dec	Inc	Dec	Inc	Dec	Inc
Bentonite	o		o		o		X	
Perlite	o		o		o			o
Dia Earth	o		X		o			o
Pozzolan	o		o			X		
Sand								
Barite	o		o					
Hematite			o					
CaCl		X						
NaCl		X						
Lignosulf	X			o			o	
Diesel					o		o	
LWLca	o		o				X	
LCM	o		o		o		o	

C- BREAKDOWN OF CEMENT CLASSES

a- Classes of Cement

1) **Class A**
   A) Intended for use from the surface down to 6,000 feet when special properties are not required.

2) **Class B**
   A) Intended for use from the surface down to 6,000 feet when conditions require moderate-to-high sulfate resistance.

3) **Class C**
   A) Intended for use from the surface down to 6,000 feet when conditions require high early strength.

4) **Class G**
   A) Intended for use as a basic cement from the surface down to 8,000 feet as manufactured, or can be used with accelerators and retarders to cover a wide range of well depths and temperatures.
   B) No additions other than calcium sulfate or water, or both, should be blended with the clinker during manufacture.

5) **Class H**
   A) Intended for use as a basic cement from the surface down to 8,000 feet as manufactured, and can be used with accelerators and retarders to cover a wide range of well depths and temperatures.
   B) No additions other than calcium sulfate or water, or both, should be interground with the clinker during manufacture.

6) **Class J** (tentative)
   A) Intended for use as manufactured from 12,000 feet down to 16,000 feet under conditions of extremely high temperatures and pressures, or can be used with accelerators and retarders to cover a range of well depths and temperatures.
   B) No additions of retarder other than calcium sulfate or water, or both, should be interground with the clinker during manufacture.

b- API Cement Slurry Composition

1) Cement Class vs. Water Requirements
   A) These relationships vary greatly depending on:
      a) weight.
      b) thickening time.

Class	**Water** % by weight	**Water** gal/ft^3 (sack)
A	46	5.19
B	46	5.19
C	56	6.32
G	44	4.97
H	46	5.19

2) When bentonite is added to cement, the percent of water must be increased.
   A) Recommendation for All Classes of Cement
      a) Add 5.3% water for each 1% bentonite.

3) Approximate Mixing Requirements for **Class A** and **Class H** Cement

Weight ppg	**Gallons of Water** per sack	**Cement Yield** ft^3 per sack
11.0	20.42	3.21
11.2	18.74	2.99
11.4	17.29	2.79
11.6	16.01	2.62
11.8	14.88	2.47
12.0	13.88	2.33
12.2	12.97	2.21
12.4	12.16	2.11
12.6	11.42	2.01
12.8	10.75	1.92
13.0	10.14	1.83
13.2	9.57	1.76
13.4	9.05	1.69
13.6	8.57	1.63
13.8	8.13	1.57
14.0	7.71	1.51
14.2	7.33	1.46
14.4	6.97	1.41
14.6	6.63	1.37
14.8	6.32	1.32
15.0	6.02	1.28
15.2	5.74	1.25
15.4	5.48	1.21
15.6	5.22	1.18
15.8	4.99	1.15
16.0	4.77	1.12
16.2	4.55	1.09
16.4	4.35	1.06
16.6	4.16	1.04
16.8	3.98	1.01
17.0	3.80	0.99
17.2	3.64	0.97
17.4	3.48	0.94
17.6	3.32	0.92
17.8	3.18	0.90
18.0	3.04	0.89

D- CEMENT CALCULATIONS

a- Constants Used

1) cement specific gravity = 3.15
2) weight of one sack = 94 pounds
3) volume of one sack = 1 cubic foot
4) density of water = 8.32 pounds per gallon
   = 62.23 pounds per cubic foot

E- FILLER CEMENT SLURRY DESIGN

a- Basic Slurries

	Slurry Weight (ppg)
Pozzolan	13.5
TXI lightweight (< 200°F BHCT)	12.4
1 - 1 Blend (TALC)	13.5
2 - 1 Blend (TALC)	13.1
Class A or H + 10% bentonite	12.9
Class C + 8% bentonite (< 200°F BHCT)	12.5

b- Design Steps

1) What is the mud weight?

- A) Adjust the slurry weight to be at least 1 pound per gallon above the mud weight or spacer weight, if a spacer is being used.

2) Are any shales or salt zones to be covered?

- A) If no, go to **3)**.
- B) If yes, add at least 10% salt based on the water weight.
  - a) If salt concentrations in the formation are above 10%, higher salt concentrations are needed to prevent flash setting of the cement.

3) Are sensitive formations covered?

- A) If no, go to **4)**.
- B) If yes, add at least 10% salt based on the water weight.
  - a) Fluid-loss additives, or fluid-loss additives in combination with salt may be used to help protect sensitive formations.

4) Is turbulent flow desired (very difficult to obtain)?

- A) If not necessary, go to **5)**.
- B) If yes:
  - a) check the rheology of the slurry without dispersant.
  - b) add an amount sufficient to place the slurry in turbulent flow.
    1. Oftentimes, a compatible spacer is run in turbulent flow ahead of the cement due to the difficulty in obtaining a cement slurry with adequate rheology.
       - A. In most cases, spacers can easily be designed for turbulent flow.
       - B. Use a minimum spacer volume which will allow 8 to 10 minutes of contact time before the cement reaches the face of the formation.
    2. Remember
       - A. Dispersants:
         - a. will tend to decrease compressive strength.
         - b. will reduce fluid loss of densified slurries.
         - c. may cause free water.
         - d. may retard under 200°F BHCT.
         - e. may enhance retarder effectiveness at all temperatures.
         - f. may not be needed where salt is used because salt thins slurries.
       - B. Certain combinations of dispersant and salt cause gelation.
       - C. Low-fluid-loss additives work by increasing viscosity and may be difficult to put in turbulent flow.

5) Is lost circulation a problem?

A) Little or No Lost Circulation

a) For minimum control, use (either/or):

1. no additives.
2. 1/4 pound per sack cellophane, 0.5% fluid-loss control agents, or latex.

B) Moderate Lost Circulation

a) Add 3 to 5 pounds per sack gilsonite and/or 1/4 to 1/2 pound per sack cellophane.

1. These additives may be used with 0.3% to 0.6% fluid-loss control agents.

C) Severe Lost Circulation

a) Add 5 to 10 pounds per sack gilsonite and/or 1/4 to 1/2 pound per sack cellophane.

1. These additives may be used with 0.5% to 1% fluid-loss control agents.

b) Thixotropic cements or other reactive spacers may have to replace filler slurry to control lost circulation.

6) Is gas migration a problem?

A) If no, go to **7)**.

B) If yes, sacrifice turbulent flow for a more viscous slurry which will gel soon after placement.

a) Use gas-block or fluid-loss additives for this purpose.

b) Gas migration into the cement can be prevented by having the cement composition near the point of gas invasion modified with a gas-flow prevention agent.

1. mixed at 1 - 1.5 gallons per sack

7) Is the annular clearance small?

A) If no, go to **8)**.

B) If yes, recommend a low-fluid-loss slurry to help prevent bridging, stuck pipe, and lost circulation.

a) These slurries also provide improved bonding.

b) Use a minimum amount of lost circulation materials when cementing liners.

c) Low-fluid-loss slurries also get better circulation patterns.

8) What is the BHCT?

A) 70°F to 120°F BHCT

a) Use 2% $CaCl_2$ to limit thickening time and increase early compressive strength.

B) 140°F to 200°F BHCT

a) Use retarder in combination with dispersant, fluid-loss agents, or latex.

b) Always consider the effect of these additives on retardation.

C) 200°F to 300°F BHCT

a) Use retarder in combination with dispersant or low-water-loss agents.

b) Always consider the effect of these additives on retardation.

c) Use silica sand above 230°F to prevent strength retrogression.

D) 275°F to 500°F BHCT

a) Use a high-temperature retarder.

F- COMPLETION CEMENT SLURRY DESIGN

a- Basic Slurries

	Slurry Weight (ppg)
Class A (< 220°F BHCT or < 4,000')	15.6
Class C (< 200°F BHCT)	14.8
Class H	15.6 - 16.5

b- Design Steps

1) What is the mud weight?
   - A) Adjust the slurry weight to be at least 1 pound per gallon above the mud weight or spacer weight.
     - a) If filler slurry is used, adjust the weight to at least 1 pound per gallon above the mud weight.
     - b) Use hematite for slurry weights above 17.5 pounds per gallon with limited amounts of dispersant (be especially careful about settling), and only if coarse silica is used.
       1. For example: if Class H + 35% coarse silica is used, this slurry will require 4.3 gallons of water per sack and will yield a weight of 17.3 pounds per gallon.
       2. Less water would require a large concentration of expensive dispersants.
       3. For these reasons, hematite is used above 17.3 to 17.5 pounds per gallon.

2) Are any shales or salt zones to be covered?
   - A) If no, go to **3)**.
   - B) If yes, add at least 10% salt based on the water weight.
     - a) If salt concentrations in the formation are above 10%, higher salt concentrations are needed to prevent flash setting of the cement.

3) Are sensitive formations to be covered?
   - A) If no, go to **4)**.
   - B) If yes, add at least 10% salt based on the water weight.
     - a) Fluid-loss additives in combination with salt may be used to help protect sensitive formations.
     - b) Salt and fluid-loss additives can sometimes result in viscous slurries and reduction of fluid-loss effectiveness.
   - C) Hold water loss to 8.3cc - 16.7cc per 30 minutes at BHCT.

4) Is turbulent flow desired?
   - A) If not necessary, go to **5)**.
   - B) If yes:
     - a) check the rheology of the slurry at BHCT without dispersant.
     - b) add an amount sufficient to place the slurry in turbulent flow, or consider using a spacer designed to achieve turbulence ahead of the cement.
   - C) Remember
     - a) Dispersants:
       1. will reduce fluid loss of densified slurries.
       2. will cause free water when used excessively.
       3. will tend to cause settling.
       4. may retard under 200°F BHCT.
       5. may enhance retarder effectiveness at all temperatures.
       6. may not be needed where salt is used because salt thins slurries.
     - b) Certain combinations of dispersant and salt cause gelation.
     - c) Low-fluid-loss additives work by increasing viscosity and may be difficult to put in turbulent flow.

5) Is lost circulation a problem?

A) Little or No Lost Circulation

a) For minimum control, use (either/or):

1. no additives.
2. $^1/_4$ pound per sack cellophane, 0.5% fluid-loss control agents, or latex.

B) Moderate Lost Circulation

a) Add 3 to 5 pounds per sack gilsonite and/or $^1/_4$ to $^1/_2$ pound per sack cellophane.

1. These additives may be used with 0.3% to 0.6% fluid-loss control agents.

C) Severe Lost Circulation

a) Add 5 to 10 pounds per sack gilsonite and/or $^1/_4$ to $^1/_2$ pound per sack cellophane.

1. These additives may be used with 0.5% to 1% fluid-loss control agents.

b) Excessive amounts of lost circulation additives will probably block off the liner hangers.

c) Consider the use of reactive spacers.

6) Is gas migration a problem?

A) If no, go to **7)**.

B) If yes, sacrifice turbulent flow for a more viscous slurry which will gel soon after placement.

a) Use fluid-loss additives for this purpose.

b) To prevent gas channeling, hold fluid loss to 1cc - 2cc per 30 minutes at BHCT.

7) Is the annular clearance small?

A) If no, go to **8)**.

B) If yes, recommend a low-fluid-loss slurry to help prevent bridging, stuck pipe, and lost circulation.

a) These slurries also provide improved bonding.

b) Use a minimum amount of lost circulation materials when cementing liners.

1. On a high-pressure, high-temperature well, hold fluid loss to 50cc - 100cc per 30 minutes at BHCT.
2. Consider the effect of excessive retardation on compressive strength development of cement near the top of a long liner.

8) What is the BHCT?

A) The BHCT affects the following slurry properties:

a) thickening time (pumping time)

1. most important property affected

b) strength development

c) permeability

d) fluid loss

e) rheology

f) free water

B) 70°F to 120°F BHCT

a) Use 2% $CaCl_2$ to limit thickening time and increase early compressive strength.

C) 140°F to 200°F BHCT

a) Use retarder in combination with dispersant, fluid-loss agents, or latex.

b) Always consider the effect of these additives on retardation.

D) 200°F to 300°F BHCT

a) Use retarder in combination with dispersant or low-water-loss agents.

b) Always consider the effect of these additives on retardation.

c) Use silica sand above 230°F to prevent strength retrogression.

E) 275°F to 500°F BHCT

a) Use a high-temperature retarder.

G- SQUEEZE CEMENT SLURRY DESIGN

a- Basic Slurries

	Slurry Weight (ppg)
Thixotropic (light)	11.0 - 13.0
Thixotropic (Class H)	13.8 - 14.9
Class A	15.6
Class C	14.8
Class H	15.6 - 16.5

b- Design Steps

1) For the design of squeeze cement see **Volume 3, Chapter 28.**

H- WHIPSTOCK PLUG SLURRY DESIGN

a- Basic Slurries

1) Most Common: Class H densified to 17 ppg with dispersants

	Slurry Weight (ppg)
Class C	16.0 - 17.5
Class C + 10% sand	14.5 - 15.0
Class C + 20% sand	14.5 - 15.3
Class C + 10% sand + 10% silica flour	14.5 - 15.3
Class H	16.0 - 17.0
Class H + 10% sand	16.0 - 18.0
Class H + 20% sand	16.0 - 18.0
Class H + 10% sand + 10% silica flour	16.0 - 18.0
Class H + 20% sand + 20% silica flour	16.0 - 17.5

b- Design Steps

1) What is the mud weight?
- A) Adjust the slurry weight to be as near the mud weight as possible.

2) Are any shale or salt zones to be covered?
- A) If no, go to **3)**.
- B) If yes, use 2% $CaCl_2$ in the plug for quick gelation and minimum salt contamination.
  - a) However, to prevent flash-set type situations, a high salt percent cement would probably be best suited.

3) Is lost circulation a problem?
- A) If no, go to **4)**.
- B) If yes, set a rapidly gelling plug a few feet above the desired depth to limit migration downhole into lost circulation, or reactive spacers.

4) Is water flow a problem?
- A) If no, go to **5)**.
- B) If yes, set a viscous plug with higher than normal rheology to minimize contamination.
  - a) Consider a thixotropic cement.

5) What is the BHCT?
- A) 70°F to 120°F
  - a) Use 2% $CaCl_2$ to limit thickening time and increase gel strength.
- B) 140°F to 200°F
  - a) Keep thickening times to placement time + 30 minutes.
- C) 200°F to 300°F
  - a) Keep thickening times to placement time + 30 minutes.
  - b) Use silica sand above 230°F to prevent strength retrogression.
- D) 275°F to 500°F
  - a) Use retarders for sufficient thickening time.
  - b) Use silica sand to prevent strength retrogression.

14 - OILFIELD PIPE

TABLE OF CONTENTS

A- PIPE RANGE AND LENGTHS

a- Definitions

Casing - generally refers to pipe that ranges in size from 4 1/2 inches OD to 20 inches OD.

Tubing - generally refers to pipe that ranges in size from 3/4 inch OD to 4 1/2 inches OD.

Range - refers to a joint length classification.

b- Casing

Range	Length	Average
1	16' - 25'	22'
2	25' - 34'	29'
3	36' - 45'	38'

c- Tubing

Range	Length
1	20' - 24'
2	28' - 32'

B- PIPE GRADES { 36 }

a- API Grades

Grade	Yield (in K psi)	Ultimate (in K psi)	Line Number
H40	40	60	1
J55	55	75	2
K55	55	95	3
C75	75	95	4
N80	80	100	5
C95	95	105	6
P110	110	125	7

1) Note:
   A) Line numbers 1, 2, 3 and 4 are considered "low strength".
      a) Use line numbers 1, 2, or 3 for hydrogen sulfide protection unless high strengths (L80) are required by design.
      b) Line number 4 is a heat-treated N80 designed to reduce its susceptibility to hydrogen embrittlement.
   B) Line numbers 5, 6, and 7 are considered:
      a) "high strength".
      b) safe at temperatures of 175° Fahrenheit or higher.
      c) sensitive to rough handling and hydrocarbon embrittlement.
         1. If mud is left as packer fluid, it could:
            A. damage the pipe.
            B. cause failure when the mud dehydrates.

b- Non-API Grades

Grade	Yield (in K psi)	Ultimate (in K psi)	Line Number
S80	55	95	1
S0090	90	105	2
SS95	80	100	3
S95	95	110	4
S105	95	110	5
S00125	125	135	6
S00140	140	150	7
V150	150	160	8
S00155	155	165	9

C- CONNECTIONS { 36 }

a- Definitions and Abbreviations

Coupling - a connection between two joints, usually by means of a box and pin.

LT&C - long threads and couplings

ST&C - short threads and couplings

Upset - produces a 100% efficient joint in tension. The joint is equally as strong as the pipe body or the thread. The 8-round thread is cut so that the area under the last engaged thread is equal to the cross-sectional area of the pipe body.

EUE - external upset ends

NU - non-upset, thereby having 10 threads to the inch.

Integral Joint - no couplings or collars and the pipe ends are upset before cutting the threads.

Seamless - the ID is bored out of a solid piece of steel.

ERW - electric resistance weld

b- Tapered Seal Threads

1) API 8-Round Threads
- A) "8-round " refers to 8 threads per inch.
- B) very common, easy to manufacture, rugged, proven reliable

2) API Buttress Threads
- A) Thread make-up and seals are the same as the round thread.
- B) Made-up joints reach nearly 100% efficiency.
  - a) The coupling is very long.
  - b) The threads:
    1. almost "run-out" completely so that the coupling threads are contacting the pin threads almost to the outside of the pin wall.
    2. are close to being square so that the thread flanks spread apart with great difficulty.
- C) The buttress tubing joint OD is the same as the API-NU joint.
- D) Buttress threads:
  - a) require less make-up torque.
  - b) are hard to seal after being made-up several times.
    1. not a good option for use in drilling

3) Pittsburgh 8-Acme Threads
- A) in between the two listed above

4) Premium Threads
- A) special-cut threads designed for extra strength and torque to withstand high temperatures and pressures
- B) have positive, metal-to-metal seals
- C) are other than 8-round or 10-round

c- Metal-to-Metal Seal Threads

1) Hydril (2-step) Threads
- A) It is cut on two different diameters, parallel to the axis of the pipe.
- B) The threads unite the connections together thus causing the metal-to-metal seals at the shoulder contact of the two different size diameters to form the seal.
- C) Theoretically, there are 3 seals in this connection.
  - a) at the pin-taper
  - b) at the step of the pin
  - c) at the base of the pin

2) API Extreme Line Threads
   A) integral joint and primary seals at the taper on the pin end
   B) Advantages
      a) stronger than API 8-round
         1. not as strong as buttress
      b) smaller OD than API tapered seal connections
   C) Disadvantages
      a) expensive

3) PH-6 Threads

d- Resilient Seals

1) usually Hydril connections with cut ringed grooves in which teflon seals are placed to act as corrosion barriers (CB seals)
2) not cut deep enough to dangerously weaken the coupling

e- Equivalent and Interchangeable Joints

1) $2^3/_8$ inch IF with $2^7/_8$ inch SH and API#26
2) $2^7/_8$ inch IF with $3^1/_2$ inch SH and API#31
3) $2^7/_8$ inch XH with $3^1/_2$ inch DSL
4) $3^1/_2$ inch IF with $4^1/_2$ inch SH and API#38
5) $3^1/_2$ inch XH with 4 inch SH and $3^1/_2$ inch SIF
6) 4 inch FH with $4^1/_2$ inch DSL and API#40
7) $4^1/_2$ inch XH with $4^1/_2$ inch SIF, 4 inch IF, 5 inch DSL and API#46
8) $4^1/_2$ inch IF with 5 inch XH, 5 inch SIF, $5^1/_2$ inch DSL and API#50

D- ORDERING TUBULARS

a- General

1) Does the quoted price include transportation?
   A) FOB where it is to be delivered
2) Has it been:
   A) drifted?
   B) tested?
      a) to what pressure?
   C) banded?
3) What mill is it coming from?
   A) Who end-finished the material?
   B) Does it come with mill test reports?
4) If not FOB:
   A) what is the weight restriction (by law)?
   B) how many joints can one truck legally carry?
      a) The maximum load for a truck is generally 80,000 pounds, including the weight of the truck.
   C) If loading at night or on the weekend is required, give enough notice to the yard so that overtime payments can be avoided.
5) Decide beforehand how it should be loaded.
   A) collars to the rear
   B) collars to the front
6) If pipe is being purchased sight unseen, find out:
   A) what type of pipe it is.
   B) if it was purchased new.
      a) When was it purchased?
   C) how long it has been in the hole.
   D) how long it has been on the ground.

E) what type of well it was in.
a) oil
b) gas
c) gas condensate
d) Get a breakdown of the gas and liquid composition of the produced material to see how corrosive it was.
F) what type of packer fluid was in the same well.

7) Decide how much to order versus how much is required (minus threads).
A) Multiply the number of feet of pipe needed times the Factor to arrive at how much to order.
B) Make-up Loss Multiplication Factors

Casing	ST&C	LT&C
4 1/2"	1.0073	1.0083
5"	1.0076	1.0094
5 1/2"	1.0080	1.0097
6 5/8"	1.0087	1.0108
7"	1.0087	1.0111
7 5/8"	1.0090	1.0115
8 5/8"	1.0094	1.0125
9 5/8"	1.0094	1.0132
10 3/4"	1.0094	1.0132
11 3/4"	1.0097	1.0132
13 3/8"	1.0097	1.0132
16"	1.0097	1.0132
18 5/8"	1.0111	1.0132
20"	1.0111	1.0146

8) What is the average length of a joint in the string?
A) If less than 30 feet, the tubing might have been reconditioned.
9) Measure all of the dimensions of the box and pin ends.
10) Obtain cross-over subs to get back to working string.
11) If supplementing the work string with extra pipe at the last minute, be sure to recalculate the burst and collapse pressures.
12) If purchasing used tubing, check for rod wear.
13) If purchasing used casing, ask if it is being sold as pipe that was originally a different grade when it was new.
A) Since it is now used, it has been downgraded to lower grade specs.
14) Sometimes it is a good practice to have a third party test the tubing when it arrives on location.
A) If this is done, make an arrangement with the Seller along these lines:
a) Buyer pays for all of the testing of the usable pipe and 5% of the rejects.
b) Seller pays for testing the rest of the rejects, buys back the rejects plus pays any rig time that accrues while waiting for the pipe.

b- Rental Pipe

1) Get the Pipe Supplier salesman's name and a 24 hour phone number.
2) Get a recommended transportation vendor.
3) How much will it cost per foot?
4) Any minimum footage?
5) What is the recommended torque?
6) How will damages be handled?
7) What is the retesting charge per joint?
8) To what pressure has it been tested?
A) Require an inspection report.
B) Should be inspected after each use, at the Operator's expense.
a) Sometimes this is not done.
9) Did it have full length drift?

10) Was it visually inspected?
    A) If time permits, go look at it yourself.
11) How can it be recognized when incorporating it into the string?
    A) Mark it.

c- Testing and Inspection Procedures

1) General
    A) Benefits
        a) Why buy new at high prices when serviceable used material is on hand?
        b) Avoid the expense caused by failure of defective tubing.
        c) Avoid the cost of storing used material that is junk.
        d) Maintain the market value of stored material.
        e) Gain valuable information on proper maintenance through an inspection program.
2) Common Damages
    A) Improper handling
    B) Rod wear
    C) Corrosion
        a) pitting
        b) rust
        c) electrolysis
    D) Erosion
        a) from being in high pressure wells that make sand
3) Inspection Types and Procedures

    The Operator must demonstrate that the measurements are within 2% accuracy by use of test blocks sized to approximate pipe wall thickness.

    A) Magnetic Inspection
        a) The pipe is subjected to an electric current that creates a magnetic field around the pipe.
        b) The strength of the field is a function of the thickness of the pipe.
        c) Variations in the strength of the field are known as flux leaks.
            1. indicate a defect
        d) The test detects:
            1. pits.
            2. rolled-in slugs.
            3. mechanical damage.
            4. transverse cracks.
            5. stretch-mill indentations.
            6. transverse defects.
        e) A variation in this type of inspection should detect:
            1. internal and external seams.
            2. overlaps.
            3. cracks.
            4. plug scores.
            5. rod wear.
            6. wireline corrosion.
                A. longitudinal defects
        f) Another variation in a magnetic-type test is to send a joint of pipe through two stationary coils.
            1. When one coil is energized with AC current, a signal is induced in the other coil.
            2. The output signal from the sensing coil is applied to a previously calibrated signal.
            3. When the sensing coil output signal is not within the established parameters, an alarm sounds.
            4. This test assesses the grade uniformity of the pipe.
                A. Any pipe that does not conform to established parameters is identified.

B) Gamma-Ray Inspection
   a) Particles are emitted from a source through the pipe.
   b) This measures actual wall thickness of the tube throughout its entire length.
      1. includes minimum and maximum readings
   c) Wall reductions can be measured accurately.
      1. Externally
         A. OD on the drill pipe
      2. Internally
         A. drill pipe wear in the casing
      3. Both

C) Drift Inspection
   a) A gauge ring is pulled through the tube.

D) Black Light Inspection
   a) Clean the pipe thoroughly.
   b) Spread dry powder across the critical areas such as portions of the pipe that are subject to slip and tong wear.
   c) Put a magnetic flux on the joint of pipe through the use of an electric current.
   d) With the use of a black light you can see the powder.
      1. stands up in the cracks
   e) Also used to verify defects detected by the electronic inspection methods.

E) Visual Inspection
   a) The outer surface is cleaned with wire brushes and sprayed with a rust inhibitor.
   b) Thread protectors are removed, cleaned, re-doped and re-applied.
   c) Check the threads for:
      1. galling.
      2. pulled round threads.
      3. fatigue cracks in the last engaged thread.
   d) A past threaded lead at the area of the last thread engagement of round threads would indicate that the threads became stretched when pulled at loads exceeding the yield strength of the connection.
      1. They would make-up into a coupling on the next make-up.
         A. would not have the anticipated joint strength.
         B. could have inadequate leak resistance.
      2. On repeated make-up, the threads make-up more each time.
         A. interference occurs
      3. Pins can have reduced diameter due to successive yielding by repeated make-ups.
      4. This can lead to:
         A. weakened joint strength.
         B. inadequate leak resistance.
         C. possible abutment of pin ends near the center of the coupling (in the make-up).

F) Sucker-Rod Inspection
   a) This equipment is subject to constant "tension-to-compression" stress.
      1. usually fails as a result of fatigue
   b) Fatigue can be accelerated by mishandling.
      1. pitting
      2. mechanical damages
   c) The rods are:
      1. checked for kinks and breaks.
      2. heated and wire brushed to remove paraffin and scale.
      3. magnetized to check for variations in the magnetic field due to cracks and corrosion.

E- COLOR CODE CLASSIFICATION OF PIPE

a- Definitions and Abbreviations

Prime Pipe - a length of pipe that meets the API specification for the specific inspections being performed.

Defect - an imperfection of sufficient magnitude to warrant rejection of the product based on the stipulations of the applicable specification.

Imperfection - a discontinuity or irregularity in the product detected by a method outlined in the applicable specification and/or recommended practice.

Marking - made with paint stencils, print sticks, and ball point paint tubes. No inspection markings should be placed over the mill stencils: it is considered an imperfection under the marking.

Grind Marks - all exploratory grind marks and repair grinds should be covered with rust-inhibiting material, except for the rejects.

Paint Bands - all are one inch wide and neatly placed on the pipe as close to the coupling or box as possible, but not on the threads.

Sequence Number - all inspected joints should have a sequential number on either the box or the pin end. Use white paint so that it can be read from the end of the length.

Standard Markings

APITG - API thread gauging
FLD - full length drift
HRC or HRB - hardness rockwall: C or B scale
VTI - visual thread inspection
SEA - special end area inspection
EMI - electro-magnetic inspection
Tested X psi - hydrostatic inspection
FLMPI - full length magnetic particle inspection
UTFL - full length ultrasonic inspection

b- New Tubing, Casing and Plain End Drill Pipe

1) New material is classified as either acceptable or unacceptable.
2) Purchasers are generally concerned with whether or not the new material meets mill specifications without any defects.
3) Classification

A) Unacceptable

Body Wall Color Band	Minimum Remaining	Meaning
yellow	< 87.5%	Repairable reject, also a yellow circle around the defect.
blue	< 87.5%	Imperfection of undetermined depth, undetermined defect, or internal defect. Imperfection is marked with white paint.
red	< 87.5%	No drift, or manufactured with the wrong drift.
red	< 87.5%	Defective box or pin, length or hardness. Red circle with a band around the pipe, the ends of which connect with the red circle.

B) Acceptable

Body Wall Color Band	Minimum Remaining	Meaning
white	100% - 87.5%	Prime, or suitably repaired.

c- Used Tubing and Casing

1) Inspection markings appear on the body, next to the box end or coupling.

Class	Body Wall Color Band	Body Wall Reduction (average remaining wall on cross-sectional area)	Minimum Remaining
2	Yellow	0 - 15%	85%
3	Blue	16 - 30%	70%
4	Green	31 - 50%	50%
5	Red	50% or >	< 50%

A) Color Defects
   a) Red band
      1. on pin = damaged pin
      2. on box = damaged box
   b) Green band
      1. band on either side of an ID (drift) restriction
   c) Green band next to a body wall color
      1. drift restriction

d- Used Drill Pipe

1) Tube Inspection Markings

Class	Body Wall Color Band	Body Wall Reduction (average remaining wall on cross-sectional area)	Minimum Remaining
1 (new)	White (1 band)		87.5%
Premium	White (2 bands)	80.0% (no less)	80.0%
2	yellow	80.0% (no less)	65.0%
3	orange	62.5% (no less)	55.0%
Cracked (or w/hole)	red		

A) Note that the following classes of pipe will have the corresponding number of identification punches (dents).

	# of Punches
Class 1	0
Premium	1
Class 2	2
Class 3	3
Cracked	5

2) Tool Joint Inspection Markings
   A) The tool joint condition bands will appear on the extreme end of either the box or the coupling.
      a) The next inboard band will be the classification paint bands for the tool joint and drill pipe.
      b) The classification paint bands will also appear on the tube.

Body Wall Color	Meaning
red	scrap or shop repairable
green	field repairable

F- CAPACITIES, DIMENSIONS, AND STRENGTHS OF NEW PIPE

a- Definitions

Collapse Strength - a measure of the resistance of casing to failure under external pressure.

Internal Strength - a measure of the resistance of casing to failure by yielding or bursting from internal pressure. Internal pressure resulting from fluid entry or from surface pump pressure could cause casing failure by longitudinal splitting.

Yield - the amount of weight the pipe can hold "in tension". If one end is held secure in the air, how much load can be placed on it in the down direction? It is the tensile stress required to produce a total elongation of 0.5% of the gauge length as determined by an extensometer or by multiplying dividers (except when P110 is used: elongation is 0.6% of the total length). It is based on the minimum yield strength and cross-sectional area of the material of construction (also known as tensile strength or axial tension). It is the force that tends to pull the casing apart and lowers the resistance of the casing to collapse from external pressures (also known as joint strength when discussing axial tension loads at a joint). Axial loads consist of axial tension or axial compression due to buoyancy.

b- Table

Size	**2 3/8"**	**2 7/8"**	**4 1/2"**
Characteristic	T & C	T & C	ST&C
Style	upset	upset	
Description	Tubing	Tubing	Casing
Grade	J55	N80	J55
Weight	4.7	8.7	10.5
ID	1.995	2.259	4.052
Drift	1.901	2.165	3.927
OD (max)	3.063	3.668	5.000
Collapse	8,100	15,300	4,010
Burst	7,700	15,000	4,790
Body Yield	-	-	165,000
Joint Strength	71,730	198,710	132,000
Bbl/Ft	0.00387	0.00496	0.0159
Ft/Bbl	258.65	201.72	62.7
Ft^3/Ft	0.02171	0.02783	0.0895
Ft/Ft^3	46.067	35.929	11.167

15 - RUNNING PIPE AND CEMENTING

TABLE OF CONTENTS

A- GENERAL

a- Standards

1) A good primary cement job is very important because the cost of a bad primary cement job may include:
   A) costs to block squeeze.
   B) lost production days.
   C) loss of reserves.
2) The displacement fluid will usually consist of one of the following.
   A) drilling mud
   B) fresh water
   C) field salt water
   D) treated water

b- Cement Job Considerations

1) Calculate the amount of mixing water required for the cement and for displacement. **[Chapter 13]**
   A) Ensure that there is enough on location.

2) Pipe
   A) When should the pipe be on location?
   B) How should it be loaded?
      a) Check with the Toolpusher at the rig for the preferred set-up.
         1. collars to the cab
         2. collars to the rear
   C) If possible, the pipe should be received prior to reaching setting depth along with all float equipment and centralizers.
   D) Double check to ensure that the cement slurry plus additives are not abrasive enough to cause the float equipment to fail.
   E) Make sure that all cross-overs and threads are compatible.
   F) Be careful not to mis-handle the casing while off-loading.
   G) Place the casing on the racks in proper running order (i.e. - the way it will be run into the hole).
   H) After receiving all of the casing:
      a) make a diagram of:
         1. the numbering system.
         2. where each weight and grade is stacked.
      b) make a pipe talley explanation, if required.
      c) identify any spacing-out details.
      d) drift the pipe.
         1. Make sure that the pipe is clear of any ID restrictions.
      e) clean the threads.
      f) identify possible handling damages.
   I) Circulating swedges and safety valves should be checked for compatibility of threads.
   J) Hole Conditioning Considerations
      a) Ream undergauge sections.
      b) Measure the drag (resistance to pipe movement) up and down before leaving bottom.
         1. Use for correlation when casing is on bottom before cementing.
      c) Make sure that the mud weight is balanced properly.
         1. The mud going in should weigh the same as the mud coming back out.
      d) The rams will have to be changed before additional drilling is done.

3) Put the Casing Crew on "will call".

4) Put the Cementing Company on "will call".
A) Have the Cement Company perform a strength test.
a) Surface Conditions at:
1. 3 hours
2. 6 hours
3. 12 hours
4. 24 hours
b) Downhole Conditions at:
1. 3 hours
2. 6 hours
3. 12 hours
4. 24 hours
B) Always review the job requirements with the Cementer in charge.
a) How much total water is required for the job?
b) If displacing with mud and loss of returns occurs, is there enough mud in the pits at the start of the job to displace with?
c) Compare what was ordered with what the Cement Company has.
1. bulk quantities
d) Determine what their trucks can hold.
1. Compare this with what the Cement Company is supposed to have.
e) Look at the level of cement in the bulk truck to make sure that it contains as much as the Cement Company says it does.
f) Review the weight tickets.
g) Look inside of the trucks as they leave to make sure they are empty.
h) Always take both wet and dry cement samples.
i) What are the:
1. cement components for filler and primary slurry?
2. yields for filler and primary slurry?
j) What is the estimated top of the:
1. cement?
2. primary slurry?

5) Identify any float and/or rental equipment required.
A) tongs
B) elevators
C) guide and/or float shoe
D) float collar
a) Float equipment selection should be based on:
1. durability under downhole conditions.
2. resistance to deterioration when abrasives are pumped through the equipment.
3. differential pressure capability.
E) centralizers
a) Purposes
1. position the casing in the center of the hole
2. cause a uniform cement sheath
A. reduces channeling of cement
3. help prevent differential sticking of casing
4. help protect casing during reciprocation and rotation
5. aid in preventing pipe movement while the cement is setting up
A. also prevents channeling
b) Optimum Recommended Use
1. Shale or non-productive sections
A. Run a centralizer every three joints.
2. Zones of interest
A. Run two centralizers every joint.
F) stop ring
a) holds a centralizer in the middle of a joint

G) thread lock
H) pup joints
I) subs
J) multi-stage tools
   a) Types
      1. plug-operated
      2. pressure-operated
      3. drill pipe-operated
   b) Activated by:
      1. conventional cementing around the lower section.
      2. placing successive upper stages of cement through ports in the multi-stage cementing tool after the lower stage has been cemented.
   c) Reduces or eliminates the possibility of lost circulation from excessive hydrostatic pressures from heavy cement.

c- Before Running Pipe

1) Get Regulatory Authority approval to carry out the planned cement operation.
2) Decide whether or not a Welder should tack the float equipment.
3) Strap (measure) the pipe and double check the talley (figures).
4) Check the stenciling on the pipe (type, size, weight, etc.).
5) How slow should the pipe be run?
   A) Usual Recommended Speed
      a) 1,000 feet per hour
      b) 3 minutes per stand
6) Cover the bottom and the zone of interest with centralizers.
   A) Some regulations require a minimum of 1 centralizer every 4 joints over producing intervals or zones of interest.
7) Put a stop ring in the middle of the first joint.
8) Calculate the capacity of the casing. [**Chapter 13**]
9) Does the rig have a landing joint (surface pipe)?
   A) Does the landing joint have the ID that will accommodate pumpdown plugs?
   B) Leave pressure off of the cementing head.
      a) Prepare to drop slips.
         1. Clean the landing joint.
         2. Caliper the landing joint.
         3. Measure the distance from the rotary table to the spool (where the slips will land).
         4. If more drilling will be done through this string of pipe, rearrange the geolograph cord by backing out the above measured distance.

d- After Running Pipe

1) Circulate whichever is largest when the pipe is on bottom.
   A) 95% of the hole volume
   B) casing capacity
   C) bottoms up
2) When the pipe gets to bottom, reciprocate (and rotate, if possible).
3) The Cementing Contractor should not take longer than a maximum of 20 seconds to change from cement to displacement fluid.
4) Record information during the cement job.
   A) time
   B) pressure
   C) density
   D) rates
   E) volume
5) Ask the Cementers for the waiting on cement (WOC) time.
6) Nipple down the BOPs.

7) Either/Or
    - A) Nipple up the drilling spool and change series if required.
        - a) Test all new wellheads to approximately 50% of collapse.
    - B) If production pipe is run:
        - a) nipple up B section of the tree.
        - b) blank it off with a blanking flange.
            1. closes the well temporarily to allow removal of the drilling rig and later attachment of the tree

B- DURING THE CEMENT JOB { 72 }

a- Monitor

1) Operating pressure(s)
2) Casing rotation and/or reciprocation
3) Cement weight
4) Displacement volume
5) Displacement rate
6) Displacement pressure
7) Returns
8) Amount of cement left
9) Amount of mixing water left
10) Watch out for:
    - A) any leaking lines.
    - B) any flow back after a plug is bumped (set).
11) Factors that Contribute to Cementing Failures
    - A) Flash sets
        - a) wrong water concentration in the slurry mixture
        - b) wrong BHCT used in the slurry design
        - c) mechanical breakdowns
        - d) incorrect cement type
        - e) incorrect use of additives
        - f) mixing water is the wrong temperature
            1. usually a hostile climate makes the water too hot
        - g) cement is static for too long
        - h) incorrect use of spacers
        - i) contaminants in the mixing water
        - j) cement dehydration
        - k) incorrect use of retarder
    - B) Plug bumped early
        - a) the wrong plug was dropped in front of the cement
    - C) Plug did not bump
        - a) never left the head
        - b) split casing
        - c) incorrect pipe measurements in the talley
        - d) displacement calculation was incorrect
    - D) Could not finish mixing
        - a) mechanical failure
        - b) insufficient water or pressure
    - E) Gas leakage in the annulus
        - a) insufficient hydrostatic pressure
        - b) cement/mud gelation
        - c) cement did not cover the gas sands
        - d) misread the caliper log
        - e) flow from the formation through an open valve at the surface because the hydrostatic pressure on the formation decreases as the cement cures

C- CEMENT DISPLACEMENT {73}

a- Calculations

1) Calculate the following for each cement slurry, usually consisting of the lead (filler slurry) and the tail (primary slurry).

A) Volume between the casing and the hole in:

a) Barrels per Foot =

[([0.9714 x hole size^2] ÷ 1,000) - ([0.9714 x casing size^2] ÷ 1,000)]

OR **[(hole size^2 ÷ 1,029) - (casing size^2 ÷ 1,029)]**

b) Feet per Barrel =

inverse of barrels per foot

c) Cubic Feet per Foot or Annular Volume =

[(5.454 x hole size^2) x (5.454 x casing size^2)] ÷ 1,000

d) Feet per Cubic Foot =

inverse of cubic feet per foot

e) Total Barrels

 # barrels = [# sacks x yield] ÷ 5.6154

f) Total Sacks

Number of sacks based upon the cement yield

B) Hole Volume in Cubic Feet

slurry volume required = [height of the fill] x [volume of the annulus in feet^3 per foot] x [washout factor]

a) If 35% excess were elected to be used, the washout factor would be expressed as 1.35 in the above equation.
   1. excess - extra slurry to compensate for variations in hole size

b) Obtain washout or hole volume from the open hole caliper log.

C) Sacks Needed =

slurry volume in feet^3 ÷ slurry yield in feet^3 per sack

a) Ask a Cement Designer in the area about filler-type cements and primary cements.
   1. What typical designs work best for each?
   2. What is the typical yield for each?
      A. filler - about 1.8 feet^3 per sack
      B. primary - about 1.3 feet^3 per sack

b) Cement yields should be kept below 2 feet^3 per sack.

c) For approximate yield values for completion-type cements, see **Chapter 13, C-, b-** .

For the following calculations, please see **Chapter 13.**

D) Amount of Mixing Water Required

E) Displacement Volume in barrels

F) Total barrels (cement and displacement)

G) Total Pumping Time (should be less than working time)

H) Maximum Displacement Pressure

I) Maximum Pressure Limit while landing the plug.

a) For example: Final pump pressure plus 1,000 pounds.

2) Calculate the differential for each slurry.
   A) Total Differential Across Pipe after Displacement

      Differential = # feet concerned x [the weight of the fluid in the annulus - the weight of the fluid inside the pipe]

      a) Sum the total for each fluid weight.
      b) Ensure that this sum is less than the maximum rating of the float equipment.

3) Calculate the hydrostatic pressure: [**Chapter 7**]
   A) from the cement on the casing for each slurry.
      a) Sum this total to ensure that the collapse rating for the pipe is not exceeded.
   B) of the displacement fluid.
   C) Check these figures by subtracting B) from A).
      a) The result should be a number close to the value in 2) above.

4) Ensure that the hydrostatic pressures of the cement at various points in the well do not exceed the frac gradient or the formation fracturing pressures.
   A) If these pressures are exceeded:
      a) the contact between the two slurries has to be moved to a deeper depth.
      b) the cement slurries themselves have to be redesigned.
      c) consider using a multi-stage tool and cement in several stages.

D- PREREQUISITES FOR A GOOD CEMENT JOB { 70, 74 }

a- General

1) A good cement job requires:
   A) redundancy for critical equipment items.
   B) proper functioning and testing of all equipment.
      a) lines
      b) cementing head
      c) cement manifold
   C) a clean open hole.
   D) adequate clearance between the OD of the casing and the ID of the hole or another string of casing.
      a) Clearance between the hole and the casing should range from $1^1/_2$ inches to $2^1/_2$ inches.
      b) Clearance between pipe and other casing strings should range:
         1. from $^3/_4$ inch to 1 inch at the couplings.
         2. up to nearly 2 inches at the body.
   E) centralization of the casing in the open hole at critical depths.
      a) doglegs
      b) zones of interest
   F) good mud conditioning and circulation times prior to cementing.
   G) rotation and reciprocation of pipe while conditioning the mud and cementing.
   H) the use of spacers before pumping cement.
      a) use water wetting surfactants
   I) additives in the cement.
      a) fluid-loss
      b) gas migration prevention
   J) the slurry to be mixed at design density.
   K) a lab test prior to pumping slurry.
   L) a uniform blend of slurry while it is being pumped.
   M) turbulent flow during cementing, if possible.
   N) no loss of cement to the formation.
   O) the use of a weighted water such as 2% to 3% KCL as a displacement fluid.

P) the release of pressure off of the casing after cementing.
   a) After the plug bumps (sets), allow no pipe movement for at least eight hours.

b- Additional Guidelines

1) Tally the casing before reaching TD.
   A) Drill a hole deep enough to land the casing near the floor without drilling excessive rathole.
2) Accurate knowledge of the BHCT is critical.
3) To prevent annular gas flow, the cement must have:
   A) approximately 20cc or less fluid loss at BHCT and a hydrostatic pressure about 1,000 pounds greater than the formation pressure.
   B) 0% free water.
   C) a threshold retarder (an expandable cement using either hydrogen or nitrogen gas) or a filler which combats permeability.
4) Check the barite density, or other weighting material, to see if it is the same as that used to calculate the Service Company's mixing tables.
   A) Often, the mixing tables are calculated with the specific gravity of the weighting agent equal to that of the pure mineral, while the weighting agents on location are usually less than pure.
   B) More weighting agent might be required.
5) Use rheology to:
   A) recalculate the equivalent circulating densities (ECDs) during cementing.
   B) select the mix, pump, and displacement rate.
6) Determine the displacement rates for the cement job on the basis of:
   A) the type of pipe string to be cemented.
   B) mixing and pump capabilities.
   C) ECDs during cementing for typical spacer rheology.
7) Select the spacer and check the compatibility with the mud system.
   A) If they are not compatible, select another spacer.
   B) For example: do not use CaCl completion fluid as a spacer because it will cause a flash set.
8) Once the spacer has been selected, determine rheology at:
   A) bottom-hole temperature.
   B) if possible, bottom-hole pressure.
9) Use spacer volume equal to:
   A) 750 feet - 1,000 feet of annular height.
   B) 10 minutes of contact time.
10) Batch mix the spacer and slurry whenever possible.
11) Obtain hole volumes and annular velocities from 4-arm calipers.
12) Before running casing, have a casing thread x 2 inch swedge on location.
    A) transition equipment which connects (e.g.) 5 inch pipe to 2 inch pipe
13) Do not apply thread-lock to the box end of pipe.
14) Calculate the buoyed casing weight. [**Chapter 7**]
    A) During pipe reciprocation, do not exceed a drag weight that provides less than a 2 : 1 safety factor on the body or joint yield, whichever is less.
    B) Prevent the tendency of the casing to buckle by establishing a pre-planned cement top at a certain depth above the neutral point.
15) Check the cement plug launching head for size.
    A) Compare it to bail length and spread to ensure that the elevators can latch around the head.
    B) If necessary, obtain and install special bails before casing is run.
16) Place a short joint and/or a radioactive tag above the production zone for correlation purposes.
    A) If time allows, a joint can be cut in half and threaded.
17) Run the casing slow enough that surge pressures do not fracture any weak zones.

18) Determine the method and velocity of pipe movement based on:
    A) the limitations of the surface conditions.
    B) the limitations of the rig.
    C) company policy.
19) Obtain samples of the cement at different points.
    A) usually at the beginning, middle and end
20) Do not permit the Pump Truck Operator to lighten the tail slurry mix.
21) Shut down the bulk trucks at the first sign of blowing air.
    A) out of cement
22) Open the dome lids on the trucks at the conclusion of a job.
    A) Check for unused cement.
    B) Note any amount remaining.

E- CEMENTING CONDUCTOR PIPE { 75 }

a- General

1) Considerations for slurry design are:
    A) a high enough compressive strength to support the wellhead load.
    B) a short thickening time to save rig time.
2) Figure the slurry volume using at least 50% excess.
    A) What is characteristic of the area?

b- Procedure

1) Drill and ream the hole to the desired depth.
2) Pull the drill pipe.
3) Run casing.
4) Circulate the hole with the rig pump.
5) Attach a cementing head with plug to the casing.
6) Connect lines to the pump truck and cementing head.
7) Start circulation with the pump truck.
8) Pump a minimum of 5 barrels of fresh water ahead of the cement.
    A) Start mixing the cement.
9) Pump the cement until all of it is in the casing.
10) Release the plug from the cementing head.
    A) Displace until the plug bumps (sets).
11) Close the valve on the cementing head.
    A) Leave it shut until the cement cures enough to continue drilling.
12) If the cement level falls, "top off" to the surface of the ground by pumping high quality cement around the outside of the casing until the annulus stays full.

F- CEMENTING SURFACE PIPE { 75 }

a- General

1) Hole conditioning prior to cementing is extremely critical.
    A) Proper controls on the mud properties up to this point will help to ensure a good cement job.
2) Ensure that the cement meets Regulatory Authority specifications.
3) For deeper strings of surface pipe, a lightweight lead-in cement followed by a heavier-weight completion cement is used to prevent breaking down weak zones which are sometimes penetrated by longer surface strings.
4) A distinct cost advantage is sometimes realized from using a high-yield filler slurry as a lead-in rather than a low-yield completion slurry to cement the entire string.
5) Figure the slurry volume using 100% excess, depending on rig pump size(s).

b- Procedure

1) Drill and ream the hole to the desired depth.
2) Pull the drill pipe.
3) Run casing.

4) Circulate the hole with the rig pump.
5) Attach a cementing head with plugs to the casing.
    A) Make sure that the plug sequence is correct.
        a) usually a top plug and a bottom plug
6) Connect lines to the pump truck and cementing head.
7) Start circulation with the pump truck.
8) Release the bottom plug.
9) Pump 10 barrels of fresh water or spacer ahead of the cement.
    A) Start mixing the cement.
10) Pump the cement until all of it is in the casing.
11) Release the top plug.
    A) Displace until the plug bumps.
12) Release pressure to see if the float is holding.
    A) watch for flow back
13) If the cement level falls, "top off" to the surface of the ground by pumping high quality cement around the outside of the casing until the annulus stays full.

G- CEMENTING INTERMEDIATE PIPE {75}

a- General

1) When planning for intermediate cement jobs, strongly consider having the cement batch-mixed to ensure uniform density throughout.
2) Spacers should be used ahead of the cement.
3) The cement should be displaced using the top and bottom plug method.
4) On the bottom of the casing the normal configuration is a guide shoe with a float collar one joint above the shoe.
    A) Two float collars (or float shoe and float collar) can be run in the case of very long strings with a lot of cement going through the shoe.
    B) The high volumes of cement going through the float equipment will tend to "cut out" (change the size of) the valves, which will then allow the cement to flow back.
5) For very long strings run in areas of lost circulation, a multi-stage tool is normally placed in the string, situated above the loss zone.
    A) This will allow cement on the first stage to be brought from the bottom of the hole high enough to cover the zone.
        a) A first stage top plug lands on the float collar baffle at the completion of the first stage.
    B) After finishing the first stage, a bomb is dropped that opens circulating ports at the top of the tool to begin the second stage.
        a) This allows circulation to occur around the collar to remove excess cement that would prevent proper operation of the tool during the second stage.
    C) After either circulating approximately 6 hours or when the hole is clean, the second stage cement is pumped.
        a) A second stage top plug closes the tool.
        b) This will allow for the recovery of the pipe during salvage operations after the well is eventually abandoned.
6) The height of cement fill depends on what the intermediate log looks like.
    A) For example: if there is production above the 3,000 foot level, it should be covered with cement.
    B) Many times, hole conditions will restrict the amount of hydrostatic pressure that can be placed on zones in the intermediate hole.
    C) Most of the time only the bottom 3,000 feet is cemented.
7) Usually plan on 50% excess in cement volume calculations.
    A) Additives are required in this slurry.
        a) friction reducers
        b) fluid-loss additives
        c) retarders

b- Procedure

1) Conventional Cementing and Normal Stage Cementing
   A) Drill the hole to the desired depth keeping it as in-gauge as possible.
   B) Circulate the hole with the rig pump and condition the mud to low PV and YP, keeping the solids load down.
   C) Pull the drill pipe.
   D) Run intermediate pipe with float equipment and centralizers.
      a) Run pipe at speeds slow enough to prevent breaking down the hole.
   E) Attach a cementing head with plugs to the casing before the casing lands on bottom.
      a) Rig up circulating lines to the rig manifold to facilitate pipe movement.
   F) Connect lines to the pump trucks and cementing head.
   G) Start circulation with the pump truck with a rate equivalent to or greater than the annular velocity across the drill collars during drilling, if the ECDs permit.
      a) Commence casing movement.
         1. reciprocation - 15 to 30 feet
         2. rotation - 6 to 10 revolutions per minute
         3. Do not exceed the torque or tensile limits.
      b) Delay cementing until 95% of the hole volume is circulated.
         1. based on a 4-arm caliper
         2. usually best to circulate bottoms up to see that no gas feed-in is occurring
      c) Circulate the casing volume to see that there is nothing in the casing that will plug the float equipment.
      d) Stop gas inflow before cementing.
         1. involves longer pre-cementing circulating times
      e) Carefully select float equipment that will stand up to long circulating times.
      f) Re-condition the mud prior to cementing.
   H) Release the bottom plug.
   I) Pump the spacer to clean out the mud.
      a) The spacer should be batch-mixed in a well-agitated mixing vessel.
      b) Mix the spacer density one half pound higher than the mud.
      c) Check the density of the spacer.
      d) Use enough spacer volume to provide:
         1. 10 minutes of contact time at planned displacement rates.
         2. a minimum volume of 500 annular feet.
      e) Have the Service Company that is providing the spacer also provide the personnel to mix it.
         1. Check the rheology of the spacer.
         2. Have the Service Company recalculate the critical flow rate to achieve turbulent flow.
         3. Displace at that rate, if excessive ECDs are not created.
   J) Mix the cement.
      a) Displace until all of the cement to be pumped is in the casing.
      b) Never depend solely on a barrel counter for displacement.
      c) Count the displacement tanks as a means of back-up.
   K) Release the plug.
      a) Release the top plug for a single-stage job.
      b) Release the bottom shut-off plug for a multi-stage job.
   L) Begin displacement.
      a) Pump until the plug bumps.
      b) If the plug does not bump, have a contingency plan ready detailing how long pumping should continue.
         1. usually should not pump more than 10% of the displacement volume

M) If Cementing in Stages
   a) Drop a bomb and wait the calculated time.
      1. Open the ports.
      2. Circulate out any excess cement around the multi-stage tool.
   c) Wait for the cement to cure.
   d) Mix the second stage cement.
      1. Displace until the cement is in the casing.
   e) Release the top-closing plug.
      1. Displace until it bumps.
   f) Release pressure to make sure that the floats (single-stage) or multi-stage tool are holding.

N) Wait on the cement to cure.
   a) Ask the Cementing Company how long to wait.
   b) Test the wellhead to approximately 50% of collapse.

2) Continuous-Displacement Stage Cementing
   A) Same as A) through K) above.
   L) Release the top plug.
   M) Pump the measured volume of displacement fluid.
      a) The amount pumped should equal the volume of the casing between the float collar and the multi-stage collar.
      b) Usually this volume is cut short to ensure that the opening plug reaches the multi-stage tool before the first-stage top plug lands.
   N) In most cases, second-stage cementing should not begin until:
      a) the tool has been opened.
      b) the well is circulated bottoms-up from the multi-stage tool.
   O) Pump a spacer directly behind the collar opening plug.
   P) Mix and pump cement behind the spacer.
   Q) Follow the cement with:
      a) a collar closing plug.
      b) displacement fluid.
   R) Watch for the plug to bump.
   S) Release pressure to make sure the multi-stage tool is holding.
   T) Wait on the cement to cure.
      a) Ask the Cementing Company how long to wait.
      b) Test the wellhead to approximately 50% of collapse.

H- CEMENTING PRODUCTION PIPE { 75 }

a- General

1) The production casing cement must render a pressure-tight seal between the formation and the casing.
   A) Always use a top and bottom wiper plug.
      a) guards against lead slurry contamination
      b) gives better cement compressive strength
   B) Try to use a displacement fluid similar in weight to the completion fluid to combat the microannulus problem in Cement Bond Log interpretation.
2) The reservoir must be isolated from undesirable fluids both within the producing zone itself and from other zones penetrated during drilling.
   A) Undesirable fluids
      a) oil
      b) water
      c) gas
   B) Undesirable combinations
      a) emulsions
      b) scale deposits
      c) paraffin deposits
      d) corrosion
      e) production decline

3) The filler slurry should have some fluid-loss agents in case a shallow zone might be perforated in the future.
4) The completion slurry should also have:
   A) good fluid-loss control.
   B) high compressive strength to:
      a) support the weight of the pipe.
      b) bond the pipe to the formation.
5) Setting times should be kept to a minimum to reduce the likelihood of contamination.
   A) Spacers should be utilized to remove the mud.
6) If feasible, batch-mixing should be considered to ensure uniform properties.
7) Consider renting a forklift to:
   A) rearrange material.
   B) make room on the location.
   C) increase speed and safety.
      a) For example: moving the drill pipe off of the racks and into pipe boxes on the edge of the location.
8) If the cement slurry is more than 1,500 sacks, consider having a standby pump truck on location in case the primary pump truck develops mechanical problems during the cement job.
   A) If the standby pump truck is used, there should be no charge for it.
   B) If it is not used but on location, the Operator should pay for it.
9) Make good use of thread protectors while running pipe.
   A) Galled-up threads can be extremely costly in rig time while waiting on extra pipe.

b- Procedure

1) Procedures are the same as in **G-**, **b-** above.

c- New Well

1) A new well should be blanked off with a blanking flange before rig-moving operations are begun in case the tree is accidentally damaged during such operations.

I- CEMENTING AND RUNNING LINERS {70, 76}

a- General

1) The principle advantage of running a liner over a full string of pipe is the cost savings of the shorter string.
2) Important factors to consider when running a liner are:
   A) BHCT.
   B) gas migration.
   C) depth.
   D) liner-top temperature.
   E) annular clearance.
   F) adequate liner overlap.
   G) lost circulation.
      a) LCMs will plug the circulating ports in the setting tool.
3) The liner is usually a tight fit in the open hole.
   A) Due to the limited annular space, complete mud removal should be a high priority.
   B) Spacers, pipe rotation and reciprocation will assist in mud removal.
4) Prior to designing the cement for the liner job, the BHCT must be known.
   A) This will determine the amount of retarder to use.
   B) If too much retarder is used, the cement will take much longer to cure.
      a) allows gas migration into the wet cement
      b) requires longer WOC times, which is expensive
      c) A good fluid loss target range is 2 cm^3 to 7 cm^3 per 30 minutes.
5) When figuring hole volumes, use 24% excess over the density caliper.
   A) If a conditioning trip was made, use 31% excess over the density caliper.

b- Hardware

1) Hardware Required in a Standard Liner Operation
   - A) Setting collar
     - a) used to carry the liner into the well
     - b) has a right-hand rotation to ensure easy release of the setting tool
   - B) Setting tool
     - a) used to run and set liners with 3,000 to 5,000 pounds of drill pipe weight and 12 to 15 right-hand turns
     - b) most will release the setting tool from the liner
   - C) Pack-off bushing (or swab assembly)
     - a) cements the liner where it seals the setting tool inside the liner
     - b) holds pressure on the casing side when the liner hanger is not set
     - c) There is a good surface indication when the liner is left in the hole.
       1. slight flow back in the drill pipe
   - D) Liner hanger
     - a) used to suspend the liner off of the bottom
   - E) Liner wiper plug (followed by a pumpdown plug)
     - a) keeps the mud from coming in contact with the cement
   - F) Pumpdown plug
     - a) has tapered rubber wipers of various sizes
     - b) allows the plug to wipe the inside of:
       1. tool joints
       2. upsets
       3. the liner setting string
   - G) Plug landing collar
     - a) catches and holds the liner wiper plug
       1. keeps it from moving uphole
       2. seals the liner from pressure below
       3. keeps it from turning while drilling out
     - b) A seal in this tool shears at a predetermined pressure permitting:
       1. testing of the liner and string.
       2. setting the hydraulic-operated liner hanger.
   - H) Float shoe (or a regular set shoe)
     - a) run on a float shoe/float collar configuration at least 1 joint apart on $5^1/_2$ inch or smaller liners
   - I) Cement manifold with swivel and ball-dropping sub
   - J) Polished (or packer) bore receptacles (sometimes used)
     - a) consist of:
       1. thick walled tubes with honed and highly polished IDs
       2. usually internally coated with teflon to prevent sticking or adherence of cement and other foreign materials
          - A. reduces seal friction and corrosion
     - b) provide a smooth bore and sealing surface for the insertion of production seal assemblies run on completion tubing for stimulation and production
     - c) may be installed:
       1. at the top of the liner
       2. in the tubing string at the transition point
       3. in the tie-back string
       4. in a tapered production liner between different ODs
       5. in a combination of 1. through 5.
       6. Normal lengths are from 10 feet to 30 feet.

c- Basic Practices

1) Test all materials.
2) Measure everything that goes in the hole.
3) Use a cleansing, compatible spacer with fluid-loss control.
   A) This spacer should be:
      a) 0.5 ppg more dense than the mud.
      b) less dense than the cement.
   B) Spacer volume should be enough to provide at least 10 minutes of contact time across the zone of interest.
   C) Spacers should be in turbulent flow even if the cement is not in turbulent flow at the time of placement.
      a) Spacers with this ability are available.
4) Most liner cementing problems can be eliminated if:
   A) the hole does not have doglegs.
   B) the mud is in good shape.
5) Know the proper volume of cement required to get the proper fill.
   A) If a caliper was used, volumes can be obtained from the caliper on the Open Hole Log.
6) Use a cement with good fluid-loss control.
   A) Adjust it to minimize:
      a) gas migration.
      b) bridging across permeable zones and reduced annular areas.
7) Have an accurate knowledge of the bottom-hole temperatures.
   A) used to design the cement retarder
   B) temperature information source: Open Hole Log
8) Slurry density should be 1 ppg more than the mud.
9) Whenever possible, batch-mix the cement slurry.
10) When pulling out of the hole with the bit to run the liner, rabbit (check for ID restrictions) the drill pipe.
    A) If ID restrictions are found:
       a) pull the pipe.
       b) replace the restricted joint(s).
    B) ensures that the drill pipe and the pumpdown plug are compatible
11) Change rams to fit the liner in case the well starts coming in and must be closed in.
12) Subs that will be needed to run the liner should be on the rig floor.
13) Always reciprocate and rotate the liner while circulating and conditioning the hole and the mud.
14) Generally 3 to 4 hours pumping (thickening) time is adequate for most liner jobs.
15) If a well control problem occurs, it will usually happen after cementing the liner.
    A) Have a contingency plan set up.
    B) Review it with all hands.

d- Procedure

1) General
   A) Factors that Affect the Cement Bond
      a) hole deviation
      b) pipe centralization
      c) lack of pipe movement
      d) close clearances
      e) small annular areas
      f) lost circulation
      g) abnormal pressures
      h) gas migration through the cement
   B) Liner running procedures will vary a great deal among liner manufacturers.
      a) Consult the manufacturer's representative for instructions specific to their liner.

C) General Procedure Overview
   a) Run the liner to about 1 foot off of bottom.
   b) Condition the mud.
   c) Release the setting tool from the liner by right-hand rotation.
   d) Mix the cement.
      1. Pump it into the drill pipe through the cement manifold.
   e) Release the drill pipe wiper plug in the manifold and displace by mud until it latches into the liner wiper plug on the bottom of the liner setting tool.
      1. This causes a small increase in the pressure before the two plugs shear and are displaced as one unit to the plug landing collar.
      2. These plugs will latch.
      3. Pressure build-up at the surface should be observed.
   f) Remove the setting tool and the drill pipe from the well.
      1. There should be cement left in the casing above the liner top.
         A. It is easier and cheaper to drill cement than to squeeze the liner top.
      2. This will be indicated by flow back.
      3. Sometimes it is advisable to stop at some point on the way out of the hole and reverse circulate.
         A. Carefully watch returns because the ECD might push the cement to below the liner top.

2) During the design/planning phase of a liner operation, the following should be determined:
   A) burst
   B) collapse
   C) tension
   D) clearances

3) The type of liner to be run is selected.
   A) Liner Types
      a) Hydraulic set
         1. preferred in deviated holes because rotation to set the liner may not be possible.
      b) Mechanically set
         1. right-hand rotation
            A. reduces the risk of backing off drill pipe
         2. left-hand rotation
   B) Other Considerations for Liner Selection
      a) Liner movement during cementing operations
         1. Advantages
            A. improves the cement job
         2. Disadvantages
            A. increases the risk of getting stuck off of bottom
            B. increases swab and surge pressures
      b) The setting tool could be cemented in the hole if the hanger is not set and the setting tool is released from the liner.
         1. While rotating the liner on bottom, do not exceed 20 rpms.
            A. Accurate torque readings are required.
         2. Rotation can be accomplished by using:
            A. Rig rotary table
               a. Advantages
                  1] most economical
               b. Disadvantages
                  1] might not be able to rotate at the desired speed
                  2] difficult to accurately determine torque
                  3] slips must be set in order to remove the weight indicator as a problem diagnostic tool

- B. Power tongs
  - a. Advantages
    - 1] quick rig-up time
  - b. Disadvantages
    - 1] cannot rotate continuously for 4 to 6 hours without failure due to overheating
    - 2] have to change jaws to fit the drill pipe
- C. Power swivel
  - a. Advantages
    - 1] good rpm and torque control
  - b. Disadvantages
    - 1] takes a long time to rig-up

- c) Seal between the liner and the drill pipe
  - 1. Types
    - A. swab cup seal
    - B. polished bore receptacle (PBR)
    - C. pack-off bushing
      - a. Types
        - 1] drillable
        - 2] retrievable
      - b. generally used because it reduces the piston effects on the setting tools

4) Confirm with the Casing Crew
- A) Optimum make-up torque of the casing
- B) Handling procedures
  - a) thread locking
  - b) thread doping
  - c) fill-up frequency
  - d) etc.
- C) Strap (measure) the drill pipe to be used for running the liner.
  - a) Number each stand with chalk.
  - b) When the liner is fully run into the hole, check the weight indicator to see how it matches the calculated weight of the liner (minus buoyancy).
- D) Tie off (separate with rope) the pipe that will not be used on the trip.
- E) Location of:
  - a) float equipment
  - b) centralizers
- F) Depths of:
  - a) top of the liner
  - b) bottom of the liner (liner shoe)
  - c) float collar
  - d) plug landing collar
    - 1. Double check to make sure that there is enough room left to perforate/squeeze in the zone of interest.
  - e) length of liner overlap
    - 1. Is this sufficient?
- G) Total length of the liner
  - a) total number of joints in the liner
  - b) list all components in the liner and their lengths

5) After getting the float equipment in the hole, check the flow through the float equipment.

6) When the liner hanger is picked up, conduct an operational check.
- A) Lower the liner hanger through the:
  - a) rotary table.
  - b) slips.
  - c) setting tool.
- B) Make up a stand of drill pipe.
  - a) Guide the hanger through the BOPs at a very slow rate.
- C) Circulate the capacity of the hanger.

7) Calculate the volume between the float shoe and the plug landing collar. [**Chapter 7**]

8) Fill the hole each 100 feet while going in the hole (GIH).
   A) Run:
      a) 30 seconds per stand while in the casing.
      b) 1 minute per stand while in the open hole.
   B) When installing a hanger and setting assembly, fill the dead space (if a pack-off bushing is used in lieu of cups) between the liner setting tool and the liner hanger assembly.
      a) Use an inert gel to prevent foreign material from settling around the setting tool.

9) Before getting into the open hole with the liner, stop and fill the drill pipe.
   A) Assemble the cementing head and plug(s) on the landing joint.
      a) Set aside in the V door or the mouse hole for quick make-up.
      b) Run in the hole at 1 to 3 minutes per stand.
   B) Conduct a quick safety meeting where each individual's responsibilities are discussed.
      a) Cementers should have:
         1. all lines ready to cement.
         2. at least 30 feet of extra chicksans on the floor for the manifold.
         3. enough extra line for reciprocating.
      b) Any special connections that need to be made at the standpipe manifold should be completed.
      c) It may be necessary to circulate at the intermediate casing shoe.

10) Once the liner is in the open hole, minimize the time that it remains static.
   A) When the liner is 30 to 40 feet off bottom:
      a) pick up the landing joint.
      b) circulate.
      c) tag bottom.
   B) Pick up off of bottom about 3 feet.
      a) Break circulation using the manifold at the surface.
      b) Circulate with a slow initial rate until:
         1. pressures decrease.
         2. normal circulating rates and pressures are achieved.
   C) Circulate the hole.
      a) Monitor background gas and solids over the shaker.
      b) Note the pump pressure and speed.
      c) Condition the hole by making 2 circulations, if practical.
      d) Have the Mud Engineer on location.
         1. Circulate and condition the hole until the mud properties are comparable to those that existed at the time the interval was drilled.
   D) If conditions permit, move the liner while circulating.
      a) Reciprocate the pipe as soon as it is practical after the pipe reaches bottom.
         1. Continue until the liner is ready to cement.
      b) It is usually not a good idea to pull over 50% of the maximum pull for the weakest member of the liner/drill pipe assembly.

11) While conditioning the hole, conduct a safety meeting.
   A) Discuss:
      a) cement equipment and its hook up
      b) slurry placement
      c) pump rates
      d) maximum torque (if rotating)
      e) displacement volumes
         1. The pressure at which the shear pins shear off
      f) reversing out
      g) WOC time
      h) well control

12) Release the liner setting tool.

A) Leave approximately 10,000 pounds of drill pipe weight on the setting tool and liner top.

a) could be more depending on the situation

B) Make a chalk mark on the drill pipe even with the rig floor.

a) Pick up without stinging out of the liner hanger.

b) Verify that the liner hanger is set by noting the difference in the string weight.

13) If unable to continue circulation due to plugging or bridging in the liner or in the open hole annulus, do not break down the formation.

A) If unable to circulate, pull out of liner and reverse out any cement remaining in the drill pipe.

14) The displacement rate should be slowed prior to landing the drill pipe dart into the liner wiper plug.

A) When it latches, there should be a noticeable increase in pressure.

B) When the shear occurs, a decrease in pressure should be observed.

a) Quickly determine if displacement volumes between the liner wiper plug and the float collar need to be recalculated.

C) If there is no indication of plug shearing, pump full displacement volume plus an additional 3%.

D) When the plug bumps (with about 1,000 pounds over) bleed off the pressure to see if the float equipment is holding.

a) Know how much to over-displace in case the plug does not bump.

1. usually 1% to 6% of displacement volume

E) Catch wet and dry cement samples.

a) keep on location until a Cement Bond Log is run

15) Trip out of the hole with the drill pipe to a point above the anticipated top of the cement.

A) If the cement has been circulated above the top of the liner, there should be some flowback through the drill pipe when the setting seal is broken.

B) The flowback should stop when the drill pipe is above the cement.

a) Observe when this occurs.

b) Estimate the cement top.

C) If rotation does not back off the setting tool, circulate the long way while rotating the setting tool.

D) Usually 10 stands are pulled and then the system is reversed out to see whether or not there is any cement on bottoms up.

a) The ECD from reversing out can sometimes be enough to force the cement down below the casing shoe into the formation.

b) If reversing out is done, watch carefully for signs of losing mud.

1. If mud is lost, either/or:

A. shut down on bottoms up.

B. pull out of the hole with the drill pipe.

2. If pulling out of the hole is attempted, be sure that proper fill-ups are maintained because the well could be swabbed in.

c) The most critical information is impossible to obtain at this point.

1. The top of the cement is never known until a bit is run back to bottom after the cementing operation.

2. If this information was known, the next step could be taken with much more confidence.

d) If gas is detected on bottoms up, continue to circulate and condition the mud.

16) Observe the well for 4 to 6 hours after the plug is bumped, before tripping out of the hole with the setting tool.

A) If the setting tool is above the cement top, apply pressure to the system (about 150 pounds).

a) If this pressure bleeds off, do not pressure up again.

17) Trip (pull out of) the hole and pick up a bit.
    A) Run the bit to just above the top of the cement.
    B) Wait additional time while circulating.
        a) 24 hours after the plug is bumped
    C) Watch for mud loss.
18) Drill through the cement to the liner top.
    A) Circulate and condition the mud.
    B) Pull out of the hole and pick up a squeeze tool.
    C) Go back in the hole.
        a) Test the liner top to about 1,000 pounds over the highest expected BHP, depending on the type of completion fluid to be used.
            1. Test regardless of whether or not drilling will continue below the liner.
        b) Differential test to 1,500 pounds below the highest expected BHP or to a 10 ppg equivalent mud weight (EMW), whichever is lower.
            1. A pump truck will usually be required to do this.
        c) If the test holds:
            1. reverse out water.
            2. pull out of the hole (POOH) with the test tool.
        d) If the liner top leaks, repair the leak with a cement squeeze.
19) Go in the hole with a drill bit that fits inside the liner.
    A) Always expect that a few feet of cement have fallen inside.
    B) Drill out the cement inside the liner.

J- TIE-BACK STRINGS {77}

a- General

1) The tie-back string serves several functions.
    A) covers intermediate casing strings worn by drilling
    B) confines well pressures
    C) provides greater protection for other casing in the well
2) Sometimes the tie-back string is run from the first liner just below the intermediate casing back to the surface because the intermediate string is considered to be the most susceptible to wear during drilling.
3) Before running the tie-back string, it may be necessary to run a special milling tool to ream the inside of the receptacle in order to remove cement or cuttings.
4) A tie-back seal nipple is attached to the casing to seat in the sleeve in the top of the liner.
5) The seal nipple is fitted with seals to match the sleeve.
6) After the cement is in place, the seal nipple is lowered into the tie-back sleeve and seated firmly.
7) The connections at the surface are opened to prevent a pressure block that might raise the seal nipple out of the sleeve.
8) Avoid using back pressure valves in tie-back strings because it would be very difficult to force the seal nipple into the sleeve against fluid trapped in the liner.
9) Special orifice collars are available for use in the tie-back string:
    A) to permit restricted flow of fluid into the string.
    B) to serve as a stop for the cement plug.
10) Lightweight slurries are normally used to cement this string because:
    A) it is cheaper.
    B) it creates less pressure on the liner top.
11) Generally the only cement additive required is a retarder.
12) The retarder should be designed to produce enough thickening time to place the cement plus about an hour safety factor.
13) This will result in cement at the surface of the well not being retarded.
    A) It will dry in a few days.
14) Only a swedge in the top of the pipe is needed for the tie-back casing.
15) Float equipment is not required.

b- Procedure

1) Run the tie-back string.
2) Circulate the hole with the rig pump.
3) Connect lines to the swedge and the pump truck.
4) Start circulation with the pump truck.
5) Pump 10 barrels of water ahead of the cement slurry.
6) Mix the cement.
    A) Displace until all of the cement is in place.
7) Shut in the well.
    A) Wait for the cement to cure.

K- CEMENTING IN DEVIATED HOLES { 78 }

a- Potential Problems

1) water channels on the high side of the annulus
2) mud channels on the low side of the annulus
3) deposition of solids caused by the settling of weight material or cuttings
    A) Settling creates a continuous uncemented channel along the low side of the wellbore which can prevent mud displacement.
    B) Failure to get complete mud displacement can result in:
        a) annular migration of well fluids.
        b) casing corrosion.
        c) collapse.
        d) loss of well control.
        e) high remedial cement costs.

b- Preventing Channels

1) Adjust the yield point of the mud.
    A) Low-yield-point muds deposit solids to such an extent that complete mud displacement cannot be achieved.
    B) High-yield-point muds are required to prevent solids from settling.
    C) The yield point varies according to the deviation angle of the hole.
        a) The lower the deviation angle of the hole, the lower the yield point of the mud required to prevent settling.
2) To improve the displacement of settling-type muds:
    A) use casing centralizers.
    B) rotate and reciprocate the pipe.
    C) use a pre-flush (very low viscosity) spacer followed by a regular spacer.
    D) use cable-type wall cleaners in the permeable zones during pipe movement.

L- ATTEMPTED COMPLETION CHECKLIST

a- Make Arrangements for Completion

1) See **Volume 3 - Completion**

b- After Completion and Testing

1) Get bids submitted in writing to have the pits backfilled.
2) Check the lease to see if there is a requirement to:
    A) remove the drilling mud.
        a) If so, get bids submitted in writing.
    B) spread the drilling mud.
        a) Get the Surface Owner's written permission to spread mud.
        b) Wait until the contents of the pit(s) have dehydrated before beginning the work.

3) Pick up all trash before letting the drilling rig leave.
4) Build an all-weather pad if one does not exist.
5) Order the lease signs.
   A) A sign should be placed at the entrance showing the:
      a) Operator.
      b) well name and number.
      c) number of acres in the lease.
   B) A sign should be posted at the well showing the:
      a) Operator.
      b) well name and number.
   C) A sign should be posted on each stock tank showing the:
      a) Operator.
      b) well name and number.
      c) number of acres in the lease.
      d) lease number.
      e) permit number that authorizes commingling of the produced liquids of multiple wells, if applicable.
   D) In the case of a multiple completion, a metal tag should be placed on each flowline if more than one flowline services a well.
   E) All lettering should be at least one inch in height.
   F) *"No smoking" signs are not required but are highly recommended.*

16 - OPEN HOLE LOGGING

TABLE OF CONTENTS

A- CHECKLISTS

a- Prior to Reaching Logging Depth

1) In consultation with the Logging Company, decide which log suite to run.
   A) Look at what logs have generally been run in the area.
   B) Selection is based on the formation needing evaluation.
      a) Some tools are better suited to evaluating some formations than others.
   C) Are they available locally?
   D) Is the hole diameter large enough?
2) Considerations for Running Tools with Radioactive Sources
   A) Is the hole straight or crooked?
   B) Does the hole have any doglegs?
      a) How severe are they?
   C) Are there any depleted zones in the wellbore?
   D) Any of the above will increase the chances of sticking the tool in the hole.
3) Do you want to shoot cores or run a Formation Test?
   A) Do hole conditions allow performance of these procedures?
4) Put the Logging Unit on stand-by with:
   A) hole size.
      a) limits the kind of log that can be run
   B) expected total depth (TD).
   C) casing size in the well.
      a) depth that the casing is set
   D) mud type.
   E) an estimated logging date and time.
   F) *exact, detailed directions to the location.*
      a) Have the Dispatcher read back the directions.
5) Know the bottom-hole temperature (BHT) and its effect on the tools that are planned to be run.
   A) Are special tools required to handle the BHT?
6) Is pressure equipment required?
   A) flange
   B) lubricator
   C) pack-off
7) What are the likely weather conditions at the estimated logging time?
   A) If rain is in the forecast and if the location will not hold up, try to get the truck out there before the rain starts.
8) When the Logging Unit is called out:
   A) have the Dispatcher read back the directions.
   B) reconfirm that they are correct.
9) Give the phone number where you can be reached and the rig phone number, if available.
10) Inform Superiors
   A) The expected logging time is (*00:00 am/pm*).
   B) The apparent relative structural position of the zone of interest is (...).
      a) You have this opinion because (...).
   C) The encouraging or discouraging signs thus far are (...).
   D) Get the phone numbers where they can be contacted after the first log is out of the hole.
   E) Ask for:
      a) final instructions.
      b) decision making parameters.

b- After Reaching Logging Depth

1) Know where and how severe any doglegs are in the well.
2) Know what type of mud system is being used.
3) Upon reaching logging depth, always make a conditioning trip.
   A) Short-trip the bit back to the depth of the last bit change.
4) Watch for gas on bottoms-up after the conditioning trip.
5) Get final confirmation from the Mud Engineer assuring that the mud is in good enough condition to log.
6) Ensure that there is enough rat hole below the last zone of interest to allow all of the logging tools a chance to sample the full zone.

c- Before Arrival at the Location

1) What time will the Driller be out of the hole?
2) What time should the Loggers be on location?
   A) How much advance notice do they need?
3) Have the following information available.
   A) location of the well
      a) abstract name
      b) survey number
   B) calls (distances in feet) from the lease and survey lines
   C) ground elevation
   D) rig floor elevation
   E) the desired distribution of the field prints and final prints of the log
      a) the names and addresses of each recipient
      b) the number of copies to each one
4) Prepare information for the Logging Engineer.
   A) scales
      a) minimum and maximum values established for each of the curves
      b) individual gradations between minimum and maximum
   B) parameters
      a) limestone or sandstone matrix
      b) Rw values
         1. chloride saturation of the water in the zone of interest (zoi)

d- Upon Arrival at the Location

1) Drilling Contractor
   A) Did the Driller have trouble pulling the drill pipe out of the hole?
      a) Document those depths at which tight spots were noticed.
   B) Was the zoi drilled with low water loss and gels?
   C) Review the Mud Engineer's last report.
2) Mud Logger
   A) Slide the full Mud Log with the Offset Logs.
      a) Pick (locate) any missing section.
      b) Note the exact depth and magnitude of the missing section.
   B) Review the show reports.
      a) Look at the samples.
   C) Does the Mud Logger agree with the pipe tally?
   D) Slide the Open Hole Log with the Mud Log.
      a) Do they correlate well?
3) Logging Engineer
   A) Look for any interesting sands while logging down.
      a) Decide if a Down Log would help.
      b) It might be beneficial to at least get it on tape.
   B) Avoid excessive speeds going down.
      a) If the tool sticks, print a Tension Curve.

C) When will the Loggers be out of the hole?
   a) How long before:
      1. the film is developed?
      2. a print of the log is ready?
D) Do log calculations. [**E-**]
   a) Identify the sands that will produce.

4) Geologist/Engineer
   A) Have a structure map and production history by zone.
   B) Ensure that:
      a) calibration surveys and tool checks were conducted.
      b) the tools are in proper working condition.
      c) the sonde design/configuration (logging tool) is agreed upon.
      d) the sonde OD is calipered.
      e) the sonde has a fishing neck.
      f) the Engineer has all of the tool dimensions with him.
   C) Could the Logger get to bottom without problems?
      a) What is the Logger's TD?
      b) How much fill has occurred, if any?
      c) Were there any tight spots going in the hole?
   D) What is the maximum logging speed coming out for this particular log suite?
      a) For radioactive tools, normal logging speed is 1,800 feet per hour.
         1. Tool type determines the speed.
      b) Logging Times in feet per minute

Going in the Hole		Coming Out of the Hole	
Induction	300	Induction	30 to 50
Sonic	300	Sonic	50
Density	300	Density	30

   E) Compare the log to other logs in the area to check the validity/quality.
      a) Are they consistent?
      b) Does the repeat section repeat very well?
      c) Identify the depths at which the log is invalid due to:
         1. hole conditions.
         2. tool malfunctions.
         3. software/hardware misconnect.
         4. other natural or unnatural causes.
      d) Check the dates on the calibrations.
   F) Correlate the log to the closest well.
      a) Pick the:
         1. missing section, if any.
            A. depth
            B. magnitude
         2. sand tops in the zoi.
      b) What is the relative structural position?
         1. High/Low/Flat to which key wells?
   G) Redo the structure map, if required.
   H) Do log calculations. [**E-**]
      a) Identify the sands that will produce.
   I) Pick the:
      a) core depths.
         1. Read back the information with someone to verify the accuracy of the depths.
      b) Formation Test (FT) depths.
   J) Find out the general feeling of the Partners concerning the likelihood of them wanting to attempt a completion.

B- HIGH PRESSURE DETECTION

a- General

1) Under normal pressure there is a decrease in shale porosity with depth.
2) Under high pressure and with depth:
   A) there is a decrease in:
      a) resistivity.
      b) the salinity of the waters.
   B) there is an increase in:
      a) shale porosity.
      b) temperature gradients.
      c) sonic travel time (delta T).
      d) carbonic acid concentration (HCO_3).
      e) conductivity (sharply).

b- Causes of High Pressure {51, 79}

1) Very different piezometric fluid levels
   A) relative potentiometric water levels in artesian water systems
2) Permeable reservoirs large enough to allow pressure transmission from the deep part to the shallow part
   A) large anticline systems
   B) steeply dipping beds
3) Extremely high rates of sedimentation and subsidence in clastic environments of deposition
4) Tectonic activity
   A) faulting
   B) folding
   C) lateral sliding and slipping
   D) squeezing caused by:
      a) shifting of fault blocks
      b) diapiric salt movements
5) Osmotic and salt filtering on a regional basis
6) Post-deposition alterations (diagenetic phenomenon) that result in chemical reactions where water or gas is released
   A) Montmorillonite degrades to layered clays, which degrade to illite clays: water is released.
   B) Gypsum degrades to anhydrite: water is released.
   C) Volcanic ash degrades to clay minerals: carbon dioxide is released.
7) Secondary precipitation of cementing materials
   A) Various minerals:
      a) solidify across pore throats.
         1. calcium sulfates
         2. sodium chlorite
         3. dolomite
         4. siderite
         5. calcite
         6. silica
      b) cause permeability barriers.
      c) decrease pore space.
         1. Crystal growth in closed reservoirs increases the in situ pressure.
8) Repressuring reservoirs in secondary recovery attempts in hydrocarbon productive zones
   A) pressuring up on a hidden fault
9) Massive areal extent of salt deposition
   A) impermeable

10) Paleopressures resulting from a closed reservoir undergoing a depth change (lifted to a shallower depth) due to erosion or uplifting
11) Bottom-hole temperature changes can cause a thermodynamic effect on reservoir fluids, resulting in higher pressures.
12) The biological effects of bacterial breakdown of hydrocarbon molecules can cause a two- to three-fold volume increase within the reservoir.
13) In permafrost environments, giant frost heaves can form which increase pressure.
    A) Frost can also increase the pressure of a shut-in well.

c- Effects of High Pressure on Well Logs

1) These values increase with depth and decrease in a high-pressure zone.
    A) resistivity
    B) parts per million NaCl concentration
    C) density
    D) neutron porosity
    E) pulsed neutron, measured in 0.001 counts per minute (c/m)
2) These values decrease with depth and increase in a high-pressure zone.
    A) conductivity
    B) sonic travel time
3) Pore pressures can sometimes be calculated using the Conductivity Curve.
    A) This method is good only in the shales of the Gulf Coast.
        a) should only be used up to intermediate pipe setting points
    B) Conductivity-Pore Pressure-Gradient Table

delta M MMho	Pore Pressure lbs/gal	Gradient psi/ft
500	12.76	0.663
750	14.03	0.729
1,000	14.92	0.775
1,250	15.91	0.811
1,500	16.19	0.841
2,000	17.11	0.889
3,000	18.42	0.955
4,000	19.27	1.001

        a) Note:
            Mho = the inverse of Ohm
            MMho = 1,000 Mho
    C) When reconciling *inconsistencies* with this method of pore pressure detection, take the value from an offset well at casing point and use its mud weight to establish a ratio.
        a) Carry that ratio back up to normal pressure environments.
    D) For example: wells in the area have conductivity in a normal environment equal to 900 MMhos with 10 ppg mud. Protection pipe is set in Well A at 6,000 feet with 12 ppg mud and has 1,700 MMhos conductivity at that point. What is the pore pressure in ppg of an equivalent zone in Well B at 5,600 feet with 1,500 MMhos conductivity?

        Well A

        a) To calculate delta M, read the conductivity values from the log.

        delta M = actual conductivity in the zone of interest - conductivity in a normal pressure section

        b) 1,700 MMhos - 900 MMhos = 800 MMhos (delta M)
            1. Corresponding pore pressure by the Table reads 14+ ppg.
            2. Pipe was set with 12 ppg mud.
            3. An adjustment must be made for this inconsistency.

c) $\underline{X}$ MMhos ÷ 1,700 MMhos = 10 ppg ÷ 12 ppg
   1. 10 ÷ 12 = 0.8333333
   2. 0.8333333 x 1,700 = 1,417
   3. X = 1,417 MMhos

d) The critical conductivity value in this case is 1,417 MMhos.
   1. Values above this will indicate a pressure transition zone.
   2. Where conductivities are greater than 1,417 MMhos, mud weights of greater than 10 ppg are required.

Well B

a) $\underline{X}$ ppg ÷ 1,500 MMhos = 10 ppg ÷ 1,417 MMhos
   1. 10 ÷ 1,417 = 0.0070571
   2. 0.0070571 x 1,500 = 10.59
   3. X = 10.59 ppg

b) Adjusted pore pressure in the equivalent zone in Well B equals 10.59 ppg.

C- FLOWCHART FOR CARBONATE EVALUATION

a- Porosity

1) Is the porosity greater than 5% ?

A) No

a) Is the zoi fractured?
   1. no = not productive
   2. yes
      A. Further evaluate the fractures.
         a. e.g. - Fracture Identification Log
         b. Low degree of fractures
            1] not productive
         c. High degree of fractures
            1] Determine the fluid in the fractures.
               A] water = water production
               B] oil = oil production

B) Yes

a) What is the lithology?
   1. Dolomite or Shale
      A. Is the bulk volume of water (BVW) greater than 3% ?
         a. can range from 2% to 4% depending on the area
         b. yes = wet
         c. no
            1] Is secondary porosity present (vugs or oolites)?
               A] no = production
               B] yes
                  a] Calculate the PRI (next page).
                     1- PRI < 2% = productive
                     2- PRI 2% to 4% = water and oil
                     3- PRI > 4% = zone is probably wet

   2. Limestone
      A. Is the BVW greater than 3% ?
         a. can range from 2% to 4% depending on the area
         b. yes = high water cut
         c. no
            1] Is secondary porosity present (vugs or oolites)?
               A] no = production
               B] yes
                  a] Calculate the PRI (next page).
                     1- PRI < 2% = productive
                     2- PRI 2% to 4% = water and oil
                     3- PRI > 4% = zone is probably wet

3. Chert
   A. Is the BVW greater than 7.5% ?
      a. can range from 6% to 9% depending on the area
      b. yes = high water cut
      c. no = productive

b- Bulk Volume of Water

1) Calculate the shale volume (VolSh).

   VolSh = [GRzoi - GRcleanCO_3] ÷ [GRsh - GRcleanCO_3]

   A) Where:

GRzoi	= gamma ray value in the zone of interest
GRcleanCO_3	= gamma ray value in a clean carbonate
GRsh	= gamma ray value in shale

2) Calculate the effective porosity (PHIE). { 80 }
   A) Effective porosity can be found using the Density Log.

   PHIE = density porosity - [VolSh x shale porosity]

   density porosity = [matrix density - density correction] ÷ [matrix density - fluid density]

   B) Porosity with clay effects removed using logs other than density.

   PHIE = log porosity - [VolSh x shale porosity]

3) Calculate the bulk volume of water (BVW).

   BVW = salt water saturation (Sw) x effective porosity (PHIE)

c- Productivity Ratio Index

1) Calculate the productivity ratio index (PRI).

   PRI = neutron or density porosity x salt water saturation (Sw)

   A) Sw in this case is calculated using sonic porosity.

   PRI = BVW x [neutron or density porosity ÷ sonic porosity]

D- FRACTURE IDENTIFICATION AND EVALUATION

a- Identification using Well Logs

1) From a log that has a density with a caliper:
   A) the caliper is broken (nervous looking).
   B) the density correction is erratic or higher than normal.
      a) indicates heavy mudcake which sometimes indicates a fracture
   C) there are higher than normal density porosity readings.
      a) If normal is 3% and the reading equals 11%, it is suspect.
   D) shallow resistivity, such as from a Shallow Focus Log (SFL), reads less than the medium or the deep due to the mudcake build-up.
   E) If A), B), C), and D) exist in a clean GR section, fractures are the probable cause.
   F) Extremely high (off scale) GR values may indicate radioactive salt deposits.
      a) sometimes indicative of fractures
2) Run a four-arm caliper through the zoi.
   A) The calipers will separate in a fracture.
3) Run a gamma-ray type tool to look for fractures.
   A) In a fracture, the GR minus U+++ Curve is much less than the Total GR Counts Curve.
   B) On this log the presentation is GR and GR minus U+++ Curves.
4) A Sonic Waveform or Amplitude Curve (normally a Cased Hole Log) may be run in the open hole.
   A) If any fractures are present, they will attenuate the signals.

5) Run a four-arm dipmeter to see the effects on the caliper.
   - A) Sometimes the results have to be sent to a computing center which will then run a printout of a log.

6) A Nuclear Spectrum Log can be used as a Fracture Identification Log.
   - A) Its presentation is the counts of $K+$, $U+++$, and $TH+$.
   - B) A fracture will render a low $K+$ and a high $U+++$ value.
   - C) A Formation Microscanner Log is now on the market.

b- Log Evaluation in Fractured Reservoirs

1) Broad Generalities
   - **A)** Sonic
     - a) As the number and fraction of unusually high values (cycle skips) increases, the well quality increases.
     - b) As amplitude decreases, productivity increases.
   - **B)** Density
     - a) Unusually low densities in clean carbonates (< 45 API units) are good indications.
       1. usually accompanied by a:
          - A. washout
          - B. high density correction value
       2. Some wells have high production and do not exhibit this density character.
   - **C)** Density Correction
     - a) As corrections over +0.1 increase, the quality of the well increases.
   - **D)** Gamma-Ray
     - a) The higher the "clean rock" (< 45 API units), the greater the probability of a better than average well.
   - **E)** Conductivity
     - a) The lower the conductivity, the better the well.
   - **F)** Caliper
     - a) Washouts in low gamma-ray zones are often associated with better wells.

E- FORMULAE FOR USE IN OPEN HOLE INTERPRETATION

a- Salt Water Saturation

1) General

A) Use of the Rwa Curve

If the ratio of the Rwa value in the zoi to the value in a clean water sand is:	the probable content of the sand is:
1 : 1	water
2 : 1	show
3 : 1	hydrocarbons

2) Salt Water Saturation (Sw) Formulae { 81 }

A) Where

a	= formation factor constant: usually 0.81
F	= formation factor
	= a + porosity^m
m	= cementation exponent: usually 2 in intergranular or intercrystalline porosity, but varies with other porosity types
n	= water saturation exponent: normally use 2, but value ranges from 1.8 to 2.5
Ro	= resistivity of the invaded zone
Rt	= true formation resistivity
Rw	= formation water resistivity at formation temperature
Rwa	= apparent resistivity of the water

B) The following formulae are used at various times depending on the information available.

a) **$Sw = [\ F \times (Rw \div Rt)\ ]^{1/n}$**

1. also known as the "Archie Equation"

b) **$Sw = [\ (a \div porosity^{m}) \times (Rw \div Rt)\ ]^{1/n}$**

c) **$Sw = [\ (0.81 \times Rw) \div (porosity^{2} \times Rt)\ ]^{1/2}$**

d) **$Sw = [\ Ro \div Rt\ ]^{1/2}$**

e) **$Sw = [\ Rw \div Rwa\ ]^{1/2}$**

f) **$Sw = [\ (a \times Rw) \div (porosity^{m} \times Rt)\ ]^{1/n}$**

3) Determine Rt

A) Where:

Rild = resistivity of the Deep Induction Curve
Rilm = resistivity of the Medium Induction Curve
Rsfl = resistivity of the Spherically Focused Curve
Rt = true formation resistivity

B) Read Rild, Rilm and Rsfl from the log

a) Calculate Rsfl ÷ Rild.

1. "y" axis on most charts

b) Calculate Rilm ÷ Rild.

1. "x" axis on most charts

C) Read the Rt/Rild value at the intersection on the "tornado chart" found in most chart books.

[Rt/Rild] x Rild = the corrected Rt value

4) Determine F

A) F Value to use Based on the Lithology

Lithology	**Use F =**
unconsolidated sand	$0.62 \div porosity^{2.15}$
consolidated sand	$0.81 \div porosity^{2}$
carbonate	$0.85 \div porosity^{2.14}$ or $1 \div porosity^{2}$
clean sand	$1 \div porosity^{2.05 - porosity}$
average sand	$1.45 \div porosity^{1.54}$
limey sand	$1.45 \div porosity^{1.70}$
shaley sand	$1.65 \div porosity^{1.33}$
Miocene	$1.97 \div porosity^{1.29}$
South Louisiana	$2.45 \div porosity^{1.08}$

5) Determine Porosity

A) General

a) If grain sizes are equal, the cubic stacking porosity equals 48%.

1. In its lowest energy state porosity equals 26%.

b) Porosity values have to be corrected by removing the effects of:

1. shale volume.
   A. see shaley sand interpretation [**F-**]
   B. see carbonate flowchart (effective porosity) [**C-, b-, 2)**]
2. hydrocarbon presence.
   A. Sonic Porosity Corrections for Hydrocarbons
      a. To correct for the effect of gas:

      corrected sonic = sonic porosity x 0.7

      b. To correct for the effect of oil:

      corrected sonic = sonic porosity x 0.9

B. Density Porosity Corrections for Hydrocarbons

a. Oil does not affect the density porosity.

b. If the density of the gas is unknown, 0.7 gm/cc fluid density is used in the density porosity formula below to correct for the gas affect.

B) Sonic Porosity

a) Where:

#	= 51.2 if depth is greater than 7,000 feet
	= 56.5 if depth is less than 7,000 feet
delta T	= the value of the travel time in the zoi off of the log in microseconds/foot (msec/ft)
delta T matrix	= sand: 55.5 to 51 msec/ft
	= lime: 47.6 msec/ft
	= anhydrite: 50 msec/ft
	= salt: 67 msec/ft
	= casing: 57 msec/ft
delta T fluid	= travel time of the fluid in the hole
	fresh water mud: 189 msec/ft
	salt water mud: 185 msec/ft
delta T shale	= given on the log heading in msec/ft

1. **Sonic Porosity = [delta T - #] ÷ 138**

2. **Sonic Porosity = [(delta T - delta T matrix) ÷ (delta T fluid - delta T matrix)] x [100 ÷ delta T shale] x 100**

b) On the chart below, find the appropriate delta T shale column and read the delta T (from the zone of interest off of the log) value on the appropriate row.

1. Where these two intersect, read the % sonic porosity.
2. For example: if the delta T shale is 120 microseconds/foot and delta T from the log is 75 microseconds/foot, the sonic porosity equals 12%.

delta T from log	**delta T Shale ——>** 100	110	120	(microseconds/foot) 130	140	150
65	7.0	6.2	5.8	5.2	5.0	4.5
66	7.6	6.9	6.4	5.8	5.6	5.0
67	8.2	7.6	7.0	6.4	6.2	5.5
68	8.7	8.3	7.7	7.0	6.8	6.0
69	9.8	9.0	8.4	7.6	7.4	6.5
70	10.5	10.0	9.0	8.0	8.0	7.0
71	11.2	10.5	9.6	8.6	8.5	7.5
72	12.1	11.0	10.2	9.2	9.0	8.0
73	13.1	11.5	10.9	9.8	9.5	8.5
74	13.7	12.0	11.5	10.4	10.0	9.0
75	14.3	12.8	12.0	11.0	10.5	9.5
76	15.25	13.4	12.6	11.4	10.9	10.0
77	16.0	14.0	13.2	11.8	11.3	10.5
78	16.7	14.6	13.8	12.2	11.7	11.0
79	17.5	15.3	14.4	12.8	12.1	11.5
80	18.0	16.0	15.0	13.5	12.8	12.0
81	18.8	16.7	15.6	14.1	13.1	12.5
82	19.6	17.3	16.2	14.7	13.7	13.0
83	20.4	18.0	16.8	15.3	14.3	13.5
84	21.2	18.8	17.4	15.9	14.9	14.0
85	22.0	19.6	18.0	16.5	15.5	14.5
86	22.8	20.1	18.6	17.1	16.1	15.0
87	23.6	20.6	19.2	17.7	16.7	15.5
88	24.4	21.1	19.8	18.3	17.3	16.0

delta T from log	delta T Shale ——> 100	110	120	(microseconds/foot) 130	140	150
89	25.2	21.6	20.4	18.9	17.9	16.7
90	26.0	22.0	21.0	19.5	18.5	17.0
91	26.7	22.8	21.7	20.1	19.0	17.5
92	27.4	25.3	22.4	20.7	19.5	18.0
93	28.1	24.4	23.1	21.3	20.0	18.5
94	28.8	25.3	23.8	21.9	20.5	19.0
95	29.5	26.0	24.5	22.5	21.0	19.5
96	30.2	26.9	25.1	23.1	21.5	20.0
97	30.9	27.6	25.7	23.7	22.0	20.5
98	31.6	28.3	26.3	24.3	22.5	21.0
99	32.3	28.9	26.9	24.9	23.0	21.5
100	33.5	29.5	27.5	25.5	23.5	22.0
101	34.0	30.3	28.2	26.0	24.0	22.5
102	34.5	31.1	28.9	26.5	24.5	23.0
103	35.0	31.8	29.6	27.0	25.0	23.5
104	35.9	32.5	30.3	27.5	25.5	24.0
105	36.5	33.2	31.0	28.0	26.0	24.5
106	37.2	33.8	31.6	28.6	26.5	25.0
107	38.0	34.4	32.2	29.2	27.0	25.5
108	38.7	35.0	32.8	29.8	27.5	26.0
109	39.5	35.5	33.4	30.4	28.0	26.5
110	40.1	36.1	34.0	31.0	28.5	27.0
111	40.6	36.8	34.6	31.6	29.1	27.4
112	41.6	37.5	35.2	32.2	29.7	27.8
113	42.5	38.2	35.8	32.8	30.3	28.2
114	43.4	38.8	36.4	33.4	30.9	28.6
115	44.1	39.4	37.0	34.0	31.5	29.0
116	45.0	40.1	37.6	34.5	32.0	29.5
117	45.7	40.8	38.2	35.0	32.5	30.0
118	46.5	41.5	38.8	35.5	33.0	30.5
119	47.1	42.3	39.4	36.0	33.5	31.0
120	48.0	43.0	40.0	36.5	34.0	31.5
121	48.5	43.6	40.6	37.0	34.4	32.0
122	49.3	44.2	41.2	37.5	34.8	32.5
123	50.0	44.8	41.8	38.0	35.2	33.0
124	50.5	45.5	42.4	38.5	35.6	33.5
125	51.0	46.2	43.0	39.0	36.0	34.0
126	51.5	46.8	43.8	39.6	36.6	34.4
127	52.0	47.4	44.6	40.2	37.2	34.8

C) Density Porosity { 81 }

a) **Density Porosity = [(# - Rholog) ÷ 1.68] x 100**

1. Where:

#	= 2.65 for high porosity unconsolidated sands
	= 2.68 for low permeability consolidated sands
Rholog	= density in the zoi from the log

b) **Density Porosity = [Rhoma - Rhob] ÷ [Rhoma - Rhof]**

1. Where:

Rhoma	= matrix density in grams per cubic centimeter	
	= anhydrite:	2.96 gm/cc
	= barite:	4.48 gm/cc
	= chlorite:	2.77 gm/cc
	= dolomite:	0.876 gm/cc
	= illite:	2.53 gm/cc
	= kaolinite:	2.42 gm/cc
	= lime (calcite):	2.71 gm/cc
	= montmorillonite:	2.12 gm/cc
	= pyrite:	5.0 gm/cc
	= salt (halite):	2.032 gm/cc
	= sand:	2.648 gm/cc
	= siderite:	3.94 gm/cc
Rhob	= read off of the log in the zoi	
Rhof	= fluid density	
	fresh water mud:	1.0 gm/cc
	salt water mud:	1.1 gm/cc

D) Density/Neutron Porosity { 81 }

Den/Neu Porosity = [(neu por^2 - den por^2)$^{1/2}$] ÷ 2

a) close to true porosity in hard rock country

6) Log Cut-off Values by Rock Type

A) Clean unconsolidated sands

a) usually need 18% porosity and 58% salt water saturation

B) Tightly compacted consolidated sands

a) usually need 15% porosity and 50% salt water saturation

C) Limestones and other "hard" rocks

a) usually need 7% porosity and 45% salt water saturation

7) Determine Rw

A) If more than one method for determining Rw is used, select the lowest Rw value.

B) Guidelines by Priority

a) Measured sample

1. from the zoi in the same well
2. from the zoi in an offset well
3. from a nearby sand in the same well

b) Local knowledge

c) Water catalogs

d) Estimate from an adjacent or nearby water sand

1. Read the value from a log that has the same sand but wet.
2. Read the value off of a clean wet sand in the same well that is approximately the same depth.

C) Calculate Rw by using the formulae below.

a) Where:

F	= formation factor
Kc	= 61 + [0.1333 x temperature in °F]
Rmf	= resistivity of the mud filtrate
Ro	= resistivity of the invaded zone
Rt	= true formation resistivity
Rw	= formation water resistivity at formation temperature
SSP	= static spontaneous potential in millivolts

1. **Rw = Rt ÷ F**

2. **Rw = [Rt x porosity^2] ÷ 0.81**

3. **Rw = Ro ÷ F**

A. if 100% water sand

4. **$SSP = -Kc\log \times [Rmf \div Rw]$**
   A. Or, reduced to an easier form:
      $SSP \div Kc = \log[Rmf \div Rw]$
      a. All values are known except Rw.
      b. Substitute a range of numbers for Rw and then reduce the size of the range until the value of Rw is reached.

D) Caution regarding the Use of the Rw Formulae
   a) Estimate the formation temperature (FT).
      $FT = ST + [d \times g]$
      1. Where:
         FT = formation temperature
         ST = surface temperature
         d = depth in feet
         g = geothermal gradient in degrees per 100 feet

   b) Adjust for the downhole temperature.
      1. Below are useful general comparisons of Rw values at various temperatures based on the chloride concentration.
         A. Convert salt (NaCl) concentration to chloride concentration.
            $Cl^- = NaCl \div 1.65$
         B. Find the appropriate chloride concentration and the appropriate temperature in degrees Fahrenheit.
         C. Follow the column and row to where they intersect.
            a. Read the Rw value in Ohms per meter^2.
            b. For example: if the chloride concentration is 2,500 ppm at 150°F, the Rw value is 0.69 Ohms/meter^2.

Chloride ppm	75°F	125°F	150°F	200°F
500	6.2	3.75	3.08	2.25
600	5.1	3.0	2.55	1.88
700	4.41	2.65	2.21	1.65
800	3.88	2.3	1.95	1.43
900	3.4	2.0	1.68	1.25
1,000	3.05	1.85	1.55	1.15
1,250	2.61	1.45	1.31	0.9
1,500	2.2	1.31	1.13	0.825
1,750	1.9	1.15	0.99	0.72
2,000	1.6	0.96	0.82	0.58
2,500	1.35	0.81	0.69	0.49
3,000	1.15	0.68	0.58	0.42
3,500	1.0	0.57	0.49	0.35
4,000	0.875	0.52	0.43	0.32
4,500	0.75	0.462	0.37	0.28
5,000	0.695	0.41	0.34	0.255
5,500	0.61	0.365	0.31	0.23
6,000	0.56	0.345	0.285	0.215
7,000	0.515	0.31	0.255	0.19
8,000	0.45	0.27	0.23	0.17
9,000	0.388	0.24	0.2	0.15
10,000	0.35	0.225	0.18	0.137
12,500	0.29	0.18	0.15	0.11
15,000	0.245	0.15	0.125	0.097
20,000	0.195	0.117	0.1	0.074
25,000	0.155	0.099	0.084	0.062
30,000	0.135	0.085	0.072	0.054
35,000	0.127	0.073	0.062	0.046

Chloride ppm	75°F	125°F	150°F	200°F
40,000	0.103	0.065	0.055	0.0415
45,000	0.095	0.074	0.05	0.038
50,000	0.085	0.066	0.046	0.034
55,000	0.081	0.052	0.044	0.033
60,000	0.074	0.047	0.040	0.031
65,000	0.07	0.043	0.036	0.027
70,000	0.066	0.041	0.034	0.021
75,000	0.061	0.036	0.032	0.019

2. Where:
   - Rw1 = known resistivity
   - T1 = temperature at which R1 was measured
   - Rw2 = resistivity at T2
   - T2 = new temperature

   Rw1 x T1 = Rw2 x T2

   A. Or, reduced to solve for the desired Rw value:

   Rw2 = Rw1 x [T1 ÷ T2]

b- Lithology

1) The lithology of a formation can be determined by using:
   A) "crossplots" from the open hole chart books.
   B) the Travel Time Curve from the Sonic Log.

If **delta T** equals: (microseconds/foot)	the formation is probably:
42	dolomite
48	lime
50	anhydrite
51 - 53	consolidated sand
53	gypsum
59	unconsolidated sand
67	salt
63 - 170	shale

c- Permeability

1) Use these formulae to very roughly approximate the permeability (k), based on the particular situation.

A) Where:

C	$= 23 + 465ph - 188ph^2$ C is a function of hydrocarbon density and ph = hydrocarbon density
$k^{1/2}$	= square root of permeability
Rtirr	= deep resistivity above the transition zone
Rw	= formation water resistivity at formation temperature
Swi	= irreducible water saturation
Vcl	= clay volume
w	= textural parameter related to the cementation and saturation exponents
w^2	$= [\, 3.75 - \text{porosity} \,] + [\, ([\, \log(Rw \div Rtirr) + 2.2]^2) \div 2 \,]$

a) For a sand with greater than 1 millidarcy (md) of permeability:

$$\mathbf{k = [\, 0.136 \times porosity^{4.4} \,] \div Swi^2}$$

b) For a sand with less than 1 md of permeability {82}:

$$\mathbf{k = [\, 3.6 \times (porosity \times [1 - Vcl]^{2.8}) \,] \div Swi^2}$$

c) For a sand with less than 1 md of permeability and the irreducible water saturation is unknown {82}:

$$\mathbf{k = 171.1 \times [\, porosity \times (1 - Vcl) \,]^{3.86}}$$

d) Coats {80}

$$\mathbf{k^{1/2} = 100 \times [\, (porosity^2 \times [1 - Swi]) \div Swi \,]}$$

e) Coats and Dumanior {80}

1. $\mathbf{k^{1/2} = [\, C \times porosity^2 \times w \,] \div [\, w^4 \times (Rw \div Rtirr) \,]}$

2. $\mathbf{k^{1/2} = [\, 300 \div w^4 \,] \times [\, porosity^w \div Swi^w \,]}$

f) Timur

1. $\mathbf{k^{1/2} = 100 \times [\, porosity^{2.25} \div Swi \,]}$

2. $\mathbf{k^{1/2} = [\, 8{,}580 \times effective\ porosity^{4.4} \,] \div Swi^2}$

g) Tixier {80}

$$\mathbf{k^{1/2} = 250 \times [\, porosity^3 \div Swi \,]}$$

h) Wyllie and Rose {80}

1. For medium gravity oils:

   $\mathbf{k^{1/2} = [\, 250 \times porosity^3 \,] \div Swi}$

2. For dry gas reservoirs:

   $\mathbf{k^{1/2} = [\, 79 \times porosity^3 \,] \div Swi}$

F- SHALEY SAND INTERPRETATION { 69, 80, 83 }

a- Modifications to the "Archie Equation"

1) Where:

Csh	= conductivity of wetted shale (Sw^{-1})
Ct	= conductivity of partially water-saturated rock (Sw^{-1})
Cw	= conductivity of free water (Sw^{-1})
F	= formation factor
n	= water saturation exponent
Sw	= fractional water saturation of pore space
Vsh	= fractional wetted shale volume of rock
X	= Vsh x Csh

A) To account for the contribution of shale to a clean sand:

$$Ct = [\,(Cw \div F) \times Sw^n\,] + X$$

B) Some accepted uses of the above equation are:

a) $Ct = [\,(Cw \div F) \times Sw^n\,] + [\,Vsh^2 \times Csh\,]$

b) $Ct = [\,(Cw \div F) \times Sw^n\,] + [\,Vsh \times Csh\,]$

1. relates to the values of Sw above the irreducible water saturation

b- Salt Water Saturation in a Clean Sand

1) Where:

a	= formation factor constant: usually 0.81
F	= formation factor
m	= cementation exponent: usually 2 in intergranular or intercrystalline porosity, but varies with other porosity types
n	= water saturation exponent: normally use 2, but value ranges from 1.8 to 2.5
por	= density/neutron porosity corrected for shale
Rsh	= resistivity of shale
Rt	= true formation resistivity
Rw	= formation water resistivity at formation temperature
SP	= spontaneous potential
Sw	= salt water saturation
Swi	= irreducible water saturation
Vsh	= volume of shale

A) $$Sw = [\,(\,[([a \times Rw] \div [por^m \times Rt]) + (a \times Rw \times Vsh)] \div [(2 \times Rsh \times por^m)^2]\,)^{1/2}\,] - [\,(a \times Rw \times Vsh) \div (2 \times Rsh \times por^2)\,]$$

B) $$Sw = [\,([(a \times Rw) \div Rt] \div por^m)^{1/n}\,] - [\,([Vsh \times Rw] \div [0.4 \times Rsh]) \div por^m\,]$$

C) $$Swi = [\,(F \times Rw) \div (200 \times Rw)\,]^{1/2}$$

D) $Vsh = 1 - [\,SPlog \div SPmax\,]$

$= [\,neu\ por - den\ por\,] \div [\,neu\ shale\ por - den\ shale\ por\,]$

$= [\,neu\ por - sonic\ por\,] \div [\,neu\ shale\ por - sonic\ shale\ por\,]$

$= [\,sonic\ por - den\ por\,] \div [\,sonic\ shale\ por - den\ shale\ por\,]$

G- ZONE THICKNESS

a- True Thickness

1) To determine true zone thickness in deviated holes or in straight holes drilled in regions of high degrees of dip:

Cosine theta = T ÷ t

A) Where:
theta = dip angle
T = true thickness
t = apparent thickness

H- VERTICAL DISPLACEMENT

a- Table

1) Vertical Displacement (in feet) for Horizontal Distances and Angles of Dip
2) For example: if Well B is drilled 1,000' away and down dip from Well A in an area that has a 5° dip, the zone of interest in Well B should be approximately 88' lower than the same zone in Well A.

Dip Angle degrees	**Perpendicular to Dip** 100'	1,000'	1 mile
1	1.75	17.5	92.2
2	3.5	35	184
3	5.2	52	277
4	7	70	369
5	8.8	88	462
6	10.5	105	555
7	12.3	123	648
8	14.1	141	742
9	15.8	158	836
10	17.6	176	931
11	19.4	194	1,026
12	21.3	213	1,122
13	23.1	231	1,219
14	24.9	249	1,316
19	34.4	344	1,818
20	36.4	364	1,922
21	38.4	384	2,027
22	40.4	404	2,133
23	42.5	425	2,241
24	44.5	445	2,351
25	46.6	466	2,462
30	57.7	577	3,048
35	70	700	3,697
40	83.9	839	4,430
45	100	1,000	5,280
50	119.2	1,192	6,293
55	142.8	1,428	7,540
60	173.2	1,732	9,145

I- WATER SATURATIONS

a- Critical Water Saturations (Cw) vs. Salt Water Saturations (Sw)

1) The core analysis critical value represents a specific depth.
2) Depending on the log, the log calculated value is affected by resistivity averaging over an interval of up to four feet.
3) Consequently, the comparison of the two water values (Cw and Sw) may yield a pessimistic interpretation in thin-bedded hydrocarbon productive zones.
4) It is important that enough core samples be analyzed to give a detailed picture of the data.
   A) Make allowances for the thin-bed resistivity averaging effect.
5) Formation water saturations in the Gulf Coast productive sands commonly vary from 10% to 70% pore space because of wide variations in petrophysical properties of the rock.
6) Grain size, sorting, and cementation control the pore size and internal pore geometry of formation rock.
   A) These influence the quantity and mobility of fluids.
7) A correlation exists between basic permeability and porosity furnished from core analysis, and the critical upper limit for formation water saturation in Gulf Coast productive sandstones.
8) Comparison of formation water saturation calculated from the Resistivity Log with the charts of critical water saturation versus porosity and permeability found below will help evaluate marginal zones.
   A) If the salt water saturation from the log is greater than the critical water saturation, the zone of interest is less likely to produce hydrocarbons in commercial quantities.

b- Critical Water Saturation Table

1) If the porosity and the permeability of the zone of interest is known, the critical water saturation can be found on the table below.
2) For example: if the porosity in the zoi is 20% and the permeability at that point is 200 millidarcies, the critical water saturation is 38%.

Permeability			**Porosity**			
millidarcy	30%	25%	20%	15%	10%	5%
5,000	33	30	27	25	-	-
1,000	35.5	32	27.5	25	-	-
900	36	32.5	28	25	-	-
800	37	33	29	25	-	-
700	38	33.5	30	25	-	-
600	39	34	31	26	-	-
500	40	36	31.5	27	-	-
400	42	37	33	28	24	-
300	44	41	34.5	30	25	-
200	47	44	38	37.5	27	22
100	56	52	45	40	33	24
90	57	53	46	40.5	34	25
80	59	54	47	41	35	27
70	60	55	49	42.5	36	28
60	62	57	51	44	37.5	29
50	64	59	52	45	40	31
40	65	61	54	47	41	33
30	68	64	57	50	44	35
20	72.5	67	62	53	46	40
10	75	71	67	57	51	44
5	75	75	72	65	54	48
1	75	75	75	67	61	56

J- GULF COAST COMMERCIAL PRODUCTION PREDICTION

a- General Observations

1) In the U.S. Gulf Coast area, oil and gas reservoirs usually exist at:
   - A) pore pressures of less than 16.3 pounds per gallon.
   - B) shale resistivity ratios of less than 3.5.
   - C) pressure gradients of less than 0.85 pounds per square inch/foot.
   - D) temperatures of less than 280°F.
2) Most commercial production in the Gulf Coast can be reached without protection pipe.
   - A) Pore pressures greater than 13 pounds per gallon require protection pipe.
     - a) 12.5 pounds per gallon is more appropriate
     - b) well is much more expensive
3) Calculation of the shale resistivity ratio (srr):

   srr = normal resistivity ÷ observed resistivity

   - A) Where:

normal resistivity	= resistivity of the shale in the normal pressure regime of the hole
observed resistivity	= resistivity of the shale in the area of interest

b- Completion Guidelines {51}

1) General
   - A) Commercial Oil Fields
     - a) Most of the commercial oil fields:
       1. can be reached without protection pipe.
       2. have a range of pore pressures from normal to 13 ppg.
       3. have a shale resistivity ratio of less than 1.6.
          - A. If the srr is greater than 1.6, commercial oil does not usually exist.
   - B) Commercial Gas Fields
     - a) Most commercial gas production:
       1. must be produced with protection pipe.
       2. is found in a range of pore pressures from 13 ppg to 16.3 ppg.
       3. is found where the shale resistivity ratio is 3.0 or less.
          - A. If the srr is greater than 3.0, gas does not usually exist in commercial quantities.
2) Small Reservoirs
   - A) Wells with an srr between 3.0 and 3.5 can be commercial with gas production but will be limited by reservoir size (i.e. - one or two wells).
     - a) highly dependent on the environment of deposition
   - B) This situation can be amplified to fit a large reservoir that is highly faulted, where the faults limit the size of the reservoir.
   - C) Development drilling is tempting due to the high flow rates of these wells.
     - a) not economical
3) Non-Commercial Reservoirs
   - A) There is a very limited amount of commercial production where the srr is 3.5 or greater.
   - B) These wells are characterized by:
     - a) high pressure.
     - b) low volume.
     - c) fast drawdown.
   - C) The water in the zone is fresh water with a small amount of gas in solution.
   - D) These zones will <u>look</u> productive on the:
     - a) Open Hole Logs due to the fresh water.
     - b) sidewall core analysis due to the high volumes of gas in solution.

E) Plot of SRR vs. Depth
- a) Where the **x axis** is srr and the **y axis** is depth
  1. total depth is at the origin
  2. ground level is located at the top of the graph
- b) Note that the curve of the srr profile will trend back to the normal curve after intervals of high pressures have been encountered.
- c) One might expect to find commercial quantities of oil and gas at deeper (more normal) profiles.
  1. not usually the case
- d) Even though the srr drops below 3.5 and where pressure gradients trend back towards normal, it is rare for commercial production to be found in wells below the depth where the 3.5 ratio exists, except in certain environments of deposition.

K- LOW-RESISTIVITY PRODUCTION { 84 }

a- Causes

1) Laminated intervals
2) Dispersed and structural clay
   - A) Clay minerals are the biggest contributors to low resistivity because of their:
     - a) water-filled micro-porosity.
     - b) ability to exchange cations with pore fluids.
3) Grains in an altered framework
4) Grain size
5) Clay-lined pore throats
6) Disseminated conductive material
   - A) e.g. - pyrite
   - B) In a low-resistivity zone, the conductive agent in the rock and the combined fluid will always cause the resistivity reading to appear lower than it actually is.

b- Evaluation

1) Evaluate a low-resistivity zone using:
   - A) Mud Logs.
   - B) thin sections.
   - C) scanning electron microscopy (SEM).
   - D) X-ray diffraction.
2) Further evaluate any sand facies having more than twice the resistivity of the shale above and below.
   - A) cores
   - B) possible tests

17 - WIRELINE FORMATION TESTS

TABLE OF CONTENTS

A- TESTING CONSIDERATIONS

a- Checklist

1) If you think a Tester will be needed, to save money have them "On Stand-by" in the yard rather than on location.
2) In the case of multiple-chamber tools, fluid tests cannot usually be obtained any deeper than 25 feet off bottom with both 2.5 gallon and 2.75 gallon fluid sample chambers.
   A) Pressure tests are usually restricted to no deeper than 8 feet off bottom.
3) Decide which size tool should be run.
   A) Hole size determines the tool size.
4) Decide what size chambers are required.
   A) Large chambers are needed to test zones that are deeply invaded.
5) When did circulation stop?
6) Were any "exotic" chemicals used in the drilling mud?
   A) This can lead to erroneous mud resistivity measurements.
7) The sand should be clean enough and thick enough to test.
8) Accurately measure the resistivity of the mud filtrate (Rmf).
   A) Keep the sample until the open hole logging truck is released.
9) Decide whether or not a segregated sample should be run.
   A) This means to fill both chambers of the tool at one depth.
   B) Sometimes it is useful in zones where severe mud filtrate invasion has occurred.
10) If a segregated sample was taken, did the chloride concentration increase in the second chamber?
    A) Save the recovered sample until the open hole logging truck is released.
11) Ensure that all calculations are made after bringing all values to the equivalent temperature.
12) Get an accurate Rw value from either:
    A) the water catalog.
    B) the Offset Log.
    C) a clean water sand in the same well.
    D) See **Chapter 16** for Rw determinations.
13) What should the chloride concentration (ppm Cl-) be in the zone of interest (zoi)?
    A) Chloride concentration to salt (NaCl) concentration:

       ppm NaCl = ppm Cl- x 1.65

    B) Salt concentration to chloride (Cl-) concentration:

       ppm Cl- = ppm NaCl ÷ 1.65

    C) Calculate the ppm Cl-.
    D) Chart the ppm Cl-.
    E) Titrate the ppm Cl-.
    F) They should all approximately agree.
       a) If not, then at a minimum, the titrated value should be close to the chart value.

B- USUAL LIMITATIONS

a- Minimums and Maximums

1) The tool length is usually 45 feet with both chambers.
2) The maximum temperature environment is usually 350°F.
3) The minimum hole size is usually $6^{1}/_{4}$ inches.
4) The maximum hole size is usually $14^{3}/_{4}$ inches.
   A) If the hole is greater than 9 inches, special shoes must be added to the test tool.

C- DEFINITIONS

Drawdown Pressure - the minimum pressure reached when the test chamber is opened.

Initial Shut-in Pressure - the maximum pre-test pressure in a 10cc chamber.

Build-up Time - the time frame from when the tool is set (at the second pressure drop after hydrostatic pressure) until the maximum pressure is reached.

Sampling Range - the range of sampling pressures from the minimum drawdown pressure observed when the sample chamber is opened until the maximum pressure observed when the sample chamber is sealed.

Sampling Time - the time from chamber open to chamber sealed.

Final Shut-in - the maximum formation pressures observed in the sample chamber after it is sealed.

Hydrostatic - the hydrostatic pressure from the 10cc pre-test chamber.

Surface Chamber - the sample chamber pressure at the surface prior to removing the sample.

D- CALCULATIONS

a- Gas/Oil Ratio (GOR)

GOR = [159,000 x feet^3 free gas] ÷ #cc of oil

1) Where:
   159,000 = #cc in one barrel

b- Percent Formation Water

1) Calculate Rw. [**Chapter 16**]
2) Rrf is measured directly from the fluid sample.
3) Rmf is determined by: (most to least accurate)
   - A) If the Rrf of the first chamber of a segregated sample is greater than the measured Rmf value of a pressed sample, use it as Rmf.
     - a) if it is not a fresh water sand
   - B) If a good local knowledge of Rw is known or may be surmised from an Rwa log presentation, and if a good static spontaneous potential (SSP) can be estimated without shale effects then Rmf should be calculated from Rw and SSP. [**Chapter 16**]
   - C) Rmf from a pressed sample from a mud set at a test depth
   - D) A chlorides report from a previous mud report, particularly if the mud has changed during subsequent drilling
   - E) Rmf from a pressed sample taken from the flowline
   - F) Rmf from a pressed sample from the mud pit
   - G) The method used to find Rmf will be listed under "Remarks" on the Formation Test (FT) recovery and interpretation header.
     - a) The percent formation water using titrated chlorides is the most accurate and consistent.
4) Plot Rmf, Rrf and Rw on the Resistivity Chloride Chart.
   - A) Read the chloride concentrations in parts per million.
5) Where:

%FW	= percent formation water
Rmf	= resistivity of the mud filtrate
Rrf	= resistivity of the recovered fluid
Rw	= resistivity of the formation water at formation temperature
Cl Rmf	= chloride concentration of the mud filtrate
Cl Rrf	= chloride concentration of the recovered fluid
Cl Rw	= chloride concentration of the formation water

A) Using titrated ppm Cl-:

%FW = [Cl Rrf - Cl Rmf] ÷ [Cl Rw - Cl Rmf]

B) Using measured values for chlorides:

%FW = [Rw x (Rmf - Rrf)] ÷ [Rrf x (Rmf - Rw)]

c- Permeability

1) Where:

delta P	= initial shut-in pressure minus drawdown
	= maximum pressure minus minimum pressure
k	= permeability in millidarcies
Tsec	= build-up time in seconds

A) Using a standard probe and a 10cc pre-test chamber:

k = 28,303 ÷ [delta P x Tsec]

B) Using a large probe and a 10cc pre-test chamber:

k = 11,970 ÷ [delta P x Tsec]

d- Water Cut

1) The number of barrels of water that will be produced for every 100 barrels of total production:

WC = #cc of FW rec ÷ [#cc FW rec + #cc HC rec]

A) Where:

FW	= formation water
HC	= hydrocarbons
rec	= recovered
WC	= water cut
#cc FW	= %FW x #cc FW rec
#cc HC	= #cc oil + #cc gas at formation pressure

#cc gas at formation pressure =

[ft^3 gas rec x 28,321cc per ft^3] x

[14.7 ÷ formation pressure in psi]

e- Gallon to Cubic Centimeter Conversion

1) 1 gallon = 3,700 $centimeters^3$
2) 2.5 gallons = 9,300 $centimeters^3$
3) 2.75 gallons = 10,200 $centimeters^3$
4) 6 gallons = 22,000 $centimeters^3$

E- INTERPRETATION

a- Samples

1) It is impossible to interpret the results if you get a tool full of filtrate.
   A) If this happens, run a segregated sample.
   B) Note the differences between the two chambers.
2) A gas/oil ratio greater than 2,000 indicates gas production.
3) If the fraction of formation water is greater than 10%, water production can be expected on initial deliverability tests.
4) If a non-segregated sample is taken and all of the water recovered is filtrate plus a small amount of gas, the following interpretations can be made:

Recovery	Interpretation
< 0.5 $foot^3$	use log analysis and perm from FT
0.5 - 1 $foot^3$	possible gas
1 - 2.5 $feet^3$	probable dry gas
> 2.5 $feet^3$	gas

18 - RESERVOIR SAMPLE ANALYSIS

TABLE OF CONTENTS

A- GENERAL

a- Types of Samples

1) Samples from reservoirs are taken in the forms of:
   - A) whole cores.
   - B) sidewall cores.
   - C) drilled cuttings.
2) Whole cores are normally referred to as conventional cores.
   - A) Conventional cores can be tested to determine the effects on the formation of different:
     - a) drilling fluids.
     - b) acids.
     - c) fracture treatments.
     - d) etc.
   - B) Paleontological studies can be performed using whole cores.
     - a) When compared to the sidewall cores, whole cores provide a formation analysis which is:
       1. more lithologically representative.
       2. less physically altered.
3) Sidewall cores:
   - A) are more subject to physical alteration.
   - B) allow the coring of any or all zones in the well at various depths.
     - a) Compared to conventional cores, this is done:
       1. in a short period of time.
       2. at a much lower cost.

b- Variables that Influence the Analysis { 85 }

1) Filtrate lost from the drilling fluid
2) The degree of core flushing by the filtrate
3) Reservoir fluid properties
4) Relative permeability of the rock
5) Core handling after removal from the borehole until it arrives at the lab

c- Planning a Core Analysis Program { 85 }

1) Objectives
   - A) Define rock properties and reservoir characteristics.
   - B) Define the three-dimensional changes in rock properties.
   - C) Recover unaltered reservoir rock.
   - D) Obtain information that will allow calibration adjustments.

B- LAB ANALYST REPORT BY USUAL CATEGORY { 86, 87 }

a- General

1) Study of the reservoir samples should reveal information about the:
   - A) engineering data.
   - B) quality of the reservoir.
   - C) environment of deposition of the reservoir.
2) This type of analysis affords the opportunity to:
   - A) define lithology.
   - B) measure porosity.
   - C) measure permeability.
   - D) measure the fluid saturations of the recovered sample.
   - E) measure the gas saturations of the recovered sample.
3) From visual examination and physical measurement of these properties, a determination can usually be made about the:
   - A) lithological quality of the formation.
   - B) type of production.

b- Permeability

1) Definitions

   Darcy - that permeability which will permit a fluid of one centipoise viscosity to flow at a linear velocity of one centimeter per second for a pressure gradient of one atmosphere per centimeter.

   Permeability - a measure of the ability of a porous material to transmit fluids.

2) Other factors being equal, the rate at which oil or gas may be produced (for a given drawdown) is proportional to permeability.

3) Permeability is normally expressed in millidarcies.
   - A) centipoise = 1 dyne-second per centimeter ÷ 100
   - B) Almost all formations produce at radial flow but this relationship is close enough for oilfield purposes.
   - C) Where:

delta P	= pressure drop in atmospheres
A	= area in centimeters^2
k	= permeability in millidarcies
L	= length in centimeters
N	= fluid viscosity in centipoises
Q	= rate of flow in cubic centimeters per second

   a) **Q = [k x delta P x A] ÷ [N x L]**

   b) **k = [Q x N x L] ÷ [delta P x A]**

4) Permeability is a function of the size and shape of the pore channels in the rock.
   - A) Clean, coarse-grain sand (large pores) has high permeability.
   - B) Fine-grain sand (small pores) has low permeability.

5) Gas flow differs from liquid flow so air permeability differs from liquid permeability.
   - A) Gas molecules flow at a uniform rate through small pores.
   - B) Liquid molecules do not.
     - a) Liquid molecules next to the walls of the pores are almost stationary.
     - b) The velocity of the liquid molecules increases toward the center of the pore.
   - C) This flow performance is known as the "Klinkenberg effect".
     - a) An average Klinkenberg correction is normally applied to measure permeability values in order to correct them to equivalent liquid values.
     - b) This average correction varies.
       1. high permeability formations: from approximately 1%
       2. low permeability formations: to as much as 70%
     - c) The correction chart to determine the actual average correction for air permeability (air or nitrogen) to liquid permeability (any liquid with the viscosity of one centipoise to fit the equation of Darcy) was calculated mathematically and checked by experiments.
   - D) Klinkenberg's Formula

     kl = kg ÷ [1 + (b ÷ Pm)]

     - a) Where:

kl	= permeability of the medium to a single liquid phase completely filling the pores of the medium at a constant temperature
kg	= permeability of the medium to gas completely filling the pores of the medium at a constant temperature
b	= constant for a given gas and a given porous medium
Pm	= mean pressure at which gas is flowing

c- Porosity

1) Definition

   Porosity - the void space in the reservoir material which is available for the accumulation and storage of oil, gas, and water. Normally expressed as a percent of bulk volume.

2) "Summation of Fluids" Concept

   Total Porosity = WB + OB + GB

   A) Where:

      WB = water bulk
      OB = oil bulk
      = #cc of oil cooked out ÷ bulk of the sample
      GB = gas bulk
      = amount injected in cc ÷ bulk of the sample

3) Porosity varies with:
   A) grain size.
   B) grain size distribution in the sand.
4) Maximum theoretical porosity is 47.6%.
   A) known as cubic stacking
5) Carbonates are almost unlimited in porosity magnitude.
   A) Intercrystalline material is very similar to sands in amount of porosity but the pore sizes are normally smaller.
   B) Fractured and/or vuggy carbonates seldom have high porosity.
6) Porosity Calculations in Sample Analysis
   A) Where:

      BV = bulk volume: If pore volumes are determined by helium injection, the sum of pore and grain volume may be used to compute bulk volume.
      GV = grain volume: Sometimes calculated from dry sample weight and knowledge of average grain density. This is difficult in lithologies with varying grain densities. Boyle's Law can be used with helium as the gas to determine grain volume. Valid only on clean, dry samples.
      PV = pore volume: Measured directly on a cleaned and dried sample by re-saturation of void space (normally a helium pump technique).

      a) **Porosity % = [PV ÷ BV] x 100**

      b) **Porosity % = [(BV - GV) ÷ BV] x 100**

      c) **Porosity % = [PV ÷ (PV + GV)] x 100**

d- Water and Percent Pore Space

1) Connate water is the water that was entrapped in the pores of a formation at the time of deposition.
   A) According to the hydrostatic pull exerted, it:
      a) coats the grains of sand in the reservoir.
      b) occupies the:
         1. smallest pores.
         2. corners and crevices of the larger pores.
2) If hydrocarbons are assumed to occupy the larger pores, this water will be referred to as interstitial water saturation.
   A) If this percentage is the minimum value above the water transition zone, this is referred to as the irreducible water saturation.
   B) Interstitial water saturation is calculated from the:
      a) measured rock properties.
      b) total water saturation of cores cut with water-base muds.
   C) This calculated saturation is then used to estimate:
      a) initial hydrocarbons in place.
      b) recovery expected from solution gas drive and water drive.

3) The magnitude of the water saturation depends upon:
   A) the height above the free water table.
   B) pore size distribution.
      a) Coarse-grain sands which have large pores have low connate water contents.
      b) Silty, fine-grain sands have high connate water contents.

4) Other Water Saturations
   A) Formation water saturation is the current water saturation present in the formation, beyond the wellbore invaded zone.
      a) It may be equal to or greater than the interstitial water saturation.
      b) Water influx may have increased the water saturation above its initial value.
      c) Normally considered to be a Log Analyst's term.
   B) Total water saturation is the measured residual water in a core sample.
      a) It is normally greater than in situ values when water-base mud is used.
      b) It may approximate the formation water saturation where:
         1. oil-base mud is used.
         2. cores are recovered from above the transition zone.
      c) Normally considered to be a Core Analyst's term.

e- Oil: Percent by Volume

1) A volumetric measurement obtained by extracting oil from the reservoir sample using electrically heated retort extractors.

f- Gas: Percent by Volume

1) A volumetric measurement obtained by injecting mercury into the void space of a sample with a high pressure pump.

g- Oil: Percent by Pore Space

1) Calculated from measured data.

h- Probable Production

1) The accuracy and reliability of these predictions are affected by many factors.
   A) number of samples in the zone
   B) position in the reservoir of the samples taken
   C) quality of the sample
   D) degree of flushing of the samples by the drilling fluids
   E) stage of depletion of the reservoir
   F) experience level of the Analyst

i- Oil Gravity

1) Measured by examining the refractive index of oil using a refractometer.
2) Expressed as standard degrees API.

j- Combustible Gas

1) Measurement of combustible hydrocarbons by gas detector apparatus.

k- Lithological Description

1) Standard geological abbreviations are used for this purpose.

l- Critical Water Saturation

1) Definition

   Critical Water Saturation - the maximum water saturation permissible in the reservoir for each sample if the formation is hydrocarbon productive. Also, the critical or upper limit for formation water saturation above which a specific sample will produce a significant percentage of water with hydrocarbons.

2) This value is:
   A) determined by core analysis of:
      a) capillary pressure.
      b) relative permeability.
      c) viscosity.
   B) usually estimated from:
      a) routine permeability and porosity data.
      b) average critical water correlations.
3) This interpretation method requires a comparison of critical water saturation obtained from core data with the formation water saturation calculated from the Resistivity Log.
4) Hydrocarbon production is indicated if the actual formation water saturation in the reservoir is less than the critical value.
5) Critical water saturations (Cw) are utilized to the fullest when compared to the salt water saturation (Sw) calculations from the Open Hole Log data.
   A) If Cw is greater than Sw, the zone should produce water free.
   B) If Cw equals Sw, the zone should produce approximately 5% water.
   C) If Cw is less than Sw, the zone will produce water.

C- SIDEWALL CORE ANALYSIS

a- Sidewall Sample Analysis Sequence

1) Receive the samples at the lab.
2) Arrange and record samples from the shallowest to the deepest.
3) Puncture the tops of the jars.
   A) Draw off the vapors with a vacuum pump.
      a) sometimes through a wheat-stone bridge
   B) Record each sample reading as units of combustible gas.
4) Clean the drilling mud off of the sample.
5) Examine the sample under an ultraviolet light.
   A) Record the:
      a) lithological description.
      b) amount of fluorescence.
6) 1st Sample Portion
   A) Cut off a small portion of the core.
      a) It is shaped with the long axis parallel to the long axis of the sidewall sample.
   B) Dry the sample in a preheated oven for 45 minutes at 180°F.
   C) Measure and record the length.
   D) Mount the sample in sealing wax.
      a) Allow the wax to cool and harden.
   E) Flow nitrogen gas through the sample.
      a) Record the flow rate.
   F) Calculate the permeability to air.
   G) Correct for the Klinkenberg effect.
   H) Record the liquid permeability value.
7) 2nd Sample Portion
   A) Cut off another small portion of the sample.
   B) Treat it with a solution of para-phenylenediamine.
      a) Note the reaction (color change).
      b) The degree to which the color changes is an indication of the approximate amount of bentonitic clays present within the sample.
      c) Disadvantages
         1. difficult to differentiate between in situ bentonite and drilling mud bentonite
         2. gives a negative response in the presence of montmorillonite
            A. another swelling clay

8) Final Sample Portion
   A) Determine the porosity (summation of fluids).
      a) Weigh the sample on an electronic balance.
         1. Record the weight.
      b) Place it in a high pressure pump.
      c) Measure the sample bulk volume using the amount of mercury it displaces.
         1. Seal the pump with the sample inside.
         2. Raise the pressure to 750 psi.
         3. Measure and record the amount of mercury (Hg) that is injected.

            gas by volume = measured Hg ÷ BV of porosity sample

         4. Release the pressure.
         5. Remove the sample.
         6. Break the sample.
            A. Observe and record the pattern of injected Hg.
         7. Seal the sample in a stainless steel pressure bomb.
         8. Retort it in preheated electric stills.
            A. Run water through the cooling jackets.
               a. It takes time for the jackets to cool down.
            B. The fluid in the sample is vaporized.
            C. These vapors are liquefied by the condensing tubes.
            D. This liquid is captured in a receiving tube.
         9. Centrifuge the receiving tube to separate the oil and water.
         10. Measure and record the total water recovered.
            A. Use Average Water Curves to correct total water for shale water.

               water by volume = corrected # ÷ BV of porosity sample

         11. Measure and record the total oil recovered.
            A. Correct the oil reading to compensate for some of the oil not being recovered due to coking or incomplete condensation.

               oil by volume = corrected # ÷ BV of porosity sample

            B. Measure the oil gravity.
               a. Put a drop of oil in a capillary pipette.
               b. Place the pipette in a refractometer.
               c. Compare the refractometer reading to a curve that has been compiled from reading known gravities of oil.
               d. Report it as a specific API gravity value.
      d) Compute the porosity.

         porosity = oil by volume + water by volume + gas by volume

      e) Compute the oil by pore space.

         oil by pore space = oil by volume ÷ total porosity

      f) Compute the total water by pore space.

         total water by pore space = water by volume ÷ total porosity

9) The probable production is determined using:
   A) porosity.
   B) permeability.
   C) percent pore space saturation values.
   D) lithological characteristics.
   E) mercury injection patterns of the sample.
10) Note the samples that show abnormal saturations or alterations.
11) Estimate the critical water saturation.
   A) What is the maximum water saturation value each sample could contain in the formation if the sample is hydrocarbon productive?

B) These values are obtained from averaged data compiled from Capillary Pressure Curves.

C) New curves are not run for each sample.

D) The critical water saturation percent is dependent only upon the porosity and permeability.

a) not related to the percent water saturation by pore space (by sample analysis) derived using pre-calculated charts specific to the permeability, porosity, depth and probable production of each sample

b- When Reviewing Core Analysis Reports { 85, 86, 87 }

1) Texture

A) Silty and shaley sands show:

a) higher total water.

b) less hydrocarbon saturation.

B) The more permeable samples provide more reliable data.

C) Laminated samples show:

a) less oil saturation.

b) sometimes less water saturation.

D) Mercury penetration patterns often explain:

a) irregular saturations.

b) high waters in shaley but productive sands.

2) Fluid Saturations

A) Conditions leading to extreme flushing must be recognized.

a) Fluid loss over 5cc in the drilling mud is considered too high.

b) If water loss is 2cc or less, there is extreme flushing ahead of the bit, due to the slower rates of penetration.

c) The ideal water loss in a drilling mud when drilling a zoi is between 2cc and 5cc.

B) Permeability and critical water saturation should vary inversely.

C) Disregard fluid saturations on relatively low permeability samples where more permeable sand exists in the same interval.

D) Intermediate crude oil saturations between 4% and 7% in clean sands are too high for condensate and too low for irreducible oil.

a) Such samples are usually water productive.

b) If it is oil productive, it probably cannot be flushed to 4%.

E) Residual oil saturation is a function of:

a) depth.

b) viscosity.

c) shrinkage.

F) Oil additives in the mud frequently contaminate the samples.

a) This must be evaluated.

G) Shallow, dry, gas sands:

a) usually suffer extreme flushing.

b) commonly show total water saturations as high as 80% to 85%.

H) Combustible gas readings obtained from a sealed sidewall sample container provide a good positive criterion.

a) The absence of combustible gas is not necessarily a negative.

3) The effect on porosity and permeability of shattering the sample as it is forcibly placed in the retrieval container:

A) On Porosity

a) For example: if there is shattering on the sample and the porosity reads 24%, the actual true porosity is probably 21% to 22%.

True Porosity	Possible Error
> 24%	1% ±
24% - 20%	2% - 3% too high
19% - 15%	3% - 4% too high
14% - 10%	4% - 5% too high
< 10%	5% - 8% too high

B) On Permeability

True k in md	Expected Range of Sidewall Core k Values in md	Potential % Error
2	2 - 6	47
4	6 - 10	39
7	10 - 15	30
10	15 - 17	16
25	18 - 25	19
50	31 - 70	61
100	43 - 84	130
200	94 - 185	203
400	100 - 150	280
700	350 - 500	293
1,000	500 - 800	296
2,000	800 - 1,500	280
4,000	2,000 - 5,000	233

c- **Interpretation** {86, 87}

1) General

A) No all-purpose limits of oil or water saturations exist for interpretive purposes because of:

a) changes in rock properties.

b) changes in oil gravity and viscosity with depth and areal extent.

B) The type of cores taken also influences residual saturations, as cores of smaller diameters often show greater flushing and higher water saturations.

C) Despite these limitations, average crudes of 25° to 35° API often have core analysis residual oil values of 15% to 25% pore space.

D) Dry gas zones contain no measurable residual oil at the surface.

E) Condensate zones will usually show less than 4% pore space retrograde oil saturation.

F) Surface residual oil saturations typically increase as oil gravity decreases.

a) may exceed 50% pore space

2) Minimum Residual Oil Saturation

A) for a clean, oil-productive sand without contamination from drilling

Depth 1,000'	Degrees API	% Saturated w/o Contamination	% Saturated w/ Contamination
1 - 3	18 - 25	25% - 20%	9% or >
3 - 6	25 - 35	20% - 15%	7%
6 - 10	30 - 45	15% - 10%	6%
10 - 15	> 40	10% - 6%	6%
> 15	> 40	6% - 5%	6%

3) Residual Oil and Total Waters

Sand will Produce:	Residual Oil Value (%)	Average Total Water (%)
Condensate	1.1	63.7
Oil	14.0	57.8
Water	1.1	79.4

4) Quick Look "Rule of Thumb" for Predicting Production

	Condensate	Oil	Water
Oil Saturation % **So = oil bulk ÷ porosity**	< 3%	> 4%	< 3%
Water Saturation % **Sw = water bulk ÷ porosity**	< 72%*	< 72%	> 72%

(* = can range from 70% to 75%)

5) Differentiate a depleted sand from a normal pressure sand.

A) Depleted zones will demonstrate the following characteristics:

- a) High oil by pore space
  1. a function of gravity but will be above 20%
  2. a low gas bulk results in a high oil bulk
- b) High oil by volume
  1. greater than 7%
- c) Low combustible gas
  1. less than 10 units
- d) High water saturations
  1. a function of sand conditions
  2. greater than 50%
  3. most of the time greater than 80%

6) Predictable changes to fluid contents as the reservoir sample moves up from the reservoir to the surface {86}:

A) From an Oil-productive Formation

a) In a zone that has been badly flushed by a water-base mud:

	In Reservoir	**At Surface**
Oil	70%	12%
Gas	0%	40%
Water	30%	48%

b) In a zone that has <u>not</u> been badly flushed by a water-base mud:

	In Reservoir	**At Surface**
Oil	70%	20%
Gas	0%	50%
Water	30%	30%

c) In a zone that has been badly flushed by an oil-base mud:

	In Reservoir	**At Surface**
Oil	70%	40%
Gas	0%	30%
Water	30%	30%

B) From a Gas-productive Formation

a) In a zone that has been badly flushed by a water-base mud:

	In Reservoir	**At Surface**
Oil	0%	1%
Gas	70%	49%
Water	30%	50%

b) In a zone that has <u>not</u> been badly flushed by a water-base mud:

	In Reservoir	**At Surface**
Oil	0%	2%
Gas	70%	68%
Water	30%	30%

c) In a zone that has been badly flushed by an oil-base mud:

	In Reservoir	At Surface
Oil	0%	40%
Gas	70%	30%
Water	30%	30%

C) From a Water-productive Formation

a) In a zone that has been badly flushed by a water-base mud:

	In Reservoir	At Surface
Oil	0%	0%
Gas	0%	10%
Water	100%	90%

b) In a zone that has been badly flushed by an oil-base mud:

	In Reservoir	At Surface
Oil	0%	40%
Gas	0%	30%
Water	100%	30%

D) From a Depleted Oil-producing Formation

a) In a zone that has been badly flushed by a water-base mud:

1. Note that it looks exactly like a productive oil zone.

	In Reservoir	At Surface
Oil	30%	12%
Gas	0%	40%
Water	70%	48%

b) In a zone that has been badly flushed by an oil-base mud:

	In Reservoir	At Surface
Oil	55%	22%
Gas	15%	10%
Water	30%	68%

7) Generally Expected Results

A) priority decreases left to right

	k	Porosity	Saturation by % Pore Space		Saturation by % Bulk Volume		Gas Units
			Water	Oil	Oil	Gas	
1	1	4	85	0	0	0	0
	2	5	80	0.4	0.1	3	1
	3	6	79	0.7	0.2	3.5	2
	4	7	78	1	0.3	4	3
	5	8	77	1.25	0.4	4.5	4
	6	9	76	1.5	0.5	5	5
	7	10	75	1.75	0.6	5.5	5.5
	8	15	74	2	0.7	6	6
2	9	16	73	2.25	0.8	6.5	6.5
	10	17	72	2.75	0.9	7	7
3	25	18	70	3	1	7.5	10
	50	19	65	4	1.1	8	25
	75	20	60	5	1.2	8.5	50
	100	21	55	6	1.3	9	75
	200	22	54	6.5	1.4	9.5	100
	250	23	53	7	1.5	10	120
	500	24	52	7.5	2	11	140
	1,000	25	51	8	2.5	12	160

- B) Group 1: Non-productive
- C) Group 2: Transitional
- D) Group 3: Productive
- E) Example
  - a) Results of the core analysis indicate:
    1. k = 2
    2. por = 6
    3. gas % BV = 8
  - b) 8 would make the zone seem to be productive, however, greater priority must be given to permeability and porosity, which clearly indicate non-productive.
- F) Note:
  - a) If in one zone:
    1. waters range from 60 to 70.
    2. residual oil saturations decrease with depth.
  - b) Indicates:
    1. a possible water contact.
    2. that water and oil will be produced together.

D- CONVENTIONAL (WHOLE) CORES

a- Factors to Consider

1) Coring Point(s)
   - A) Who will pick it/them?
   - B) When will it/they be picked?
   - C) At what depth will it/they be picked?
2) Coring Tool
   - A) Who will supply it?
   - B) What size tool should be used?
     - a) core barrel size
     - b) core barrel length
3) How should coring be accomplished?
   - A) amount of weight
   - B) rotations per minute
   - C) maximum torque and drag
4) What are the decision parameters for:
   - A) when to stop coring?
   - B) whether or not multiple runs with the core barrel are required?
   - C) how long coring should continue if it is suspected that the target has been missed?
   - D) how long core barrel jamming should be wrestled with?
5) Who decides to pull the barrel?
   - A) What will this decision be based on?
6) Has the proper vehicle and packaging been identified and coordinated to get the core to the lab safely?

b- Handling the Core After it is Recovered

1) While looking at the core the same way that it came out of the hole (shallow on top and deep on bottom):
   - A) mark color stripes down the length of the core with permanent ink.
     - a) red on the right
     - b) either green or black on the left
   - B) mark off the feet on the core.
     - a) If any of the core turns up missing due to washing out or crumbling, the missing section will normally be assumed to be missing off of the bottom.
     - b) This missing section should be accounted for by comparing the core gamma-ray done in the lab to the Open Hole Log.
2) Once in the lab, run a gamma-ray over the core.
3) Take chips off of the core.

4) Cut the core in one foot intervals.
5) Cut the core in half lengthwise.
6) Prepare the retorts.
7) Drill one inch plugs from out of the core at one foot intervals.
    A) Run the permeability tests described in sidewall core analysis on these samples. [C-, a-]
8) Determine the helium porosity.
9) Perform a normal summation of fluids. [C-, a-]
    A) Because of the large sample size, a Water Curve can be calculated as the fluids are recovered from the samples.
    B) This allows a more critical evaluation of the differentiation of pore water versus shale water.
10) After re-drilling a "vertical plug" from the core, measure the vertical permeability.
11) Sometimes an x-y-z permeability measurement is taken.
12) Other possible tests available at this point are:
    A) chloride concentration.
    B) acid solubility.
    C) cation exchange capacity (CEC).
        a) measured using:
            1. toluene: cleans the oils from the sample
            2. methanol: cleans the salts from the sample

c- Whole Core (WC) Data vs. Sidewall Core (SWC) Data

1) WC engineering numbers are much more reliable than those from the SWC.
    A) Drainage numbers are more accurate.
    B) Reservoir permeability is more accurate.
    C) Reservoir porosity is much more accurate.
    D) All numbers are good to two decimal places.
        a) SWC numbers are good to the whole number.
2) The WC takes longer to clean and prepare for analysis.
    A) approximately 18 hours
3) WCs are more expensive to analyze.
4) Extra samples are available from WCs upon which special core analysis can be conducted.
5) One inch plug samples can be drawn from the WCs.
6) The WC involves the full diameter of the hole as opposed to the small diameter of the SWC.
7) When using SWCs, it is possible to miss key properties such as permeability attributed to fractures.

E- RESERVOIR SENSITIVITY EVALUATION { 88 }

a- Benefits

1) Development Drilling
    A) provides early warning of potential problems
    B) allows for corrections before bringing the well on stream
    C) reduces damage incurred during stimulation
2) Production
    A) data can be applied to offset wells
    B) decreases the likelihood of damage to development wells
3) Secondary Recovery Projects
    A) allows the establishment of design criteria that matches the process with the reservoir

b- Sensitive Minerals and their Potential Hazards {89}

1) Anhydrite:
- A) is water-sensitive.

2) Calcite:
- A) precipitates calcium-fluoride.

3) Chlorite:
- A) precipitates iron-hydroxide.
  - a) blocks pores
- B) has low water absorptive properties.
- C) exists as a coating and/or bridging in reservoir pore space.
- D) has a small effect on resistivity measurements because of moderate surface area.
- E) has acid-sensitive microporosity.

4) Clinoptilolite:
- A) has a high cation-exchange capacity.

5) Cristobalite:
- A) has a high cation-exchange capacity.

6) Glauconite:
- A) precipitates iron-hydroxide.

7) Illite:
- A) exhibits migration of fines, microporosity, and "mushing".
  - a) 2% to 5% of fibrous illite can block permeability to non-commercial status with migration of fines.
- B) has no absorbed water.
- C) exists as a pore lining or coating in pore space.
  - a) Diesel oil irrevocably damages the pore lining due to a tendency to imbibe and bind it in place by interfacial tension.
    - 1. cannot usually be reversed
- D) reduces resistivity measurements.
- E) has a moderate surface area.
- F) is slightly water sensitive.

8) Kaolinite:
- A) exhibits migration of fines.
- B) exists as discrete particles in pore spaces.
- C) has a small effect on resistivity measurements.
- D) has a low surface area.
- E) is chemically stable with acid.
  - a) effects are minimal to non-existent
- F) has vermicular stacking, thus it has a large amount of microporosity.
- G) fluids are immobile.
  - a) high porosity/low permeability
- H) "booklets" are fragile and will break off during high fluid flow velocities.
  - a) usual result: plugs the pore throats

9) Pyrite:
- A) precipitates iron-hydroxide.
- B) produces sulfate.

10) Siderite:
- A) precipitates iron-hydroxide after acid stimulation treatments unless adequate iron sequestering agents are incorporated.

11) Smectite:
    A) exhibits swelling and migration of fines.
    B) exists as a coating or bridges on pore spaces.
    C) is critical to physical and chemical formation damage.
    D) has a large reducing effect on resistivity measurements.
    E) has a high surface area.
        a) Sodium-rich types can swell from 600 to 1,000 times their size.
            1. Sometimes this swelling allows crystals to dislodge and continue plugging the permeability.
    F) Minerals in this group are:
        a) montmorillonite.
        b) montronite.
        c) saponite.
        d) hectorite.
        e) sauconite.

c- Scanning Electron Microscopy {90}

1) Three-dimensional images can be seen.
    A) grain coatings
    B) pore geometries
    C) pore coatings
    D) various mineral textures
2) Information is needed to define potential reservoir problems associated with acid- and water-sensitive minerals, and the migration of fines.
    A) characteristics of:
        a) pores
        b) pore throats
        c) cements
        d) clay minerals
    B) understanding of their spatial relationships
3) This type of information is particularly useful when selecting a formation treatment program.

d- Thin Section Analysis {90}

1) This lab method:
    A) determines the composition and distribution of the detrital, matrix and cement fractions.
    B) describes the nature and type of porosity.
    C) determines the distribution and origin of clay minerals.
2) An understanding of the distribution of sensitive minerals and their relationships to other rock-forming minerals helps to evaluate completion or stimulation problems.
3) Mineralogical history (diagenesis) can also be deduced.
    A) Reservoir behavior and sensitivity can be strongly influenced by the effects of:
        a) deposition.
        b) compaction.
        c) cementation.
        d) dissolution.
    B) Understanding the order of diagenetic events aids in the selection of:
        a) drilling and completion procedures.
        b) stimulation treatments.

e- X-Ray Diffraction Analysis {90}

1) This lab method identifies the clay mineral type through analysis of sample fractions less than four microns in size.
2) Total sample (bulk) analysis by X-ray diffraction identifies the non-clay mineralogy.
3) Identification of specific clay minerals and other fluid-sensitive minerals is necessary for designing a completion or treatment program.

F- PARTICLE SIZE ANALYSIS

a- Purpose

1) Plan gravel packs by obtaining the information needed to select gravel pack grain size. [**Volume 3, Chapter 35**]
2) A proper gravel pack grain size is essential to:
   A) controlling sand production.
   B) protecting expensive equipment.
   C) minimizing:
      a) costly liner failures.
      b) well workovers.

b- Environments of Deposition

1) Once the grain size distribution and range have been derived, the depositional environment can be interpreted more reliably.

G- MEASURING FLUORESCENCE { 91 }

a- Concept

1) Hydrocarbons are extracted from test samples.
2) The fluorescence intensity of the extract is:
   A) measured.
   B) plotted.
3) These plots can show the relative residual hydrocarbon richness of each sample.
4) Comparison of fluorescence measurements taken at different times during the extraction process indicates each sample's capacity to yield hydrocarbons.

b- Drawbacks

1) If the samples have been flushed by an oil-base drilling fluid, it is very difficult to distinguish between in situ hydrocarbons and filtrate from the oil-base mud.

H- THERMAL EXTRACTION CHROMATOGRAPHY { 91 }

a- Concept

1) Through TEC analysis of residual C1 to C35 hydrocarbons in cuttings, chips, or sidewall cores, one is able to:
   A) distinguish productive from non-productive zones.
   B) predict the type of fluid production.
   C) possibly determine the stage of depletion.
      a) subject to temperature limitations of approximately 150°F

b- Steps

1) Subject the samples to the vaporization of the residual hydrocarbons present.
2) Analyze the vapor with a gas chromatograph.
3) Determine the hydrocarbon concentration.
4) Group the hydrocarbons by carbon number.
5) Compute the percentage of total detected hydrocarbon represented by each group.
6) Plot the information.

c- Interpretation

1) Interpretation of the data is based on hydrocarbon accumulation reaction to pressure reduction.
2) The escape of hydrocarbons is limited only by their:
   A) molecular size.
   B) volatility.
3) Hydrocarbons found in the subsurface have a characteristic distribution of carbons that reflect the type of accumulation (i.e. - oil, gas, etc.).
   A) The composition of the residual hydrocarbons in the samples at the surface reflects the original reservoir composite minus components which have escaped during the procedure.

d- Advantages

1) TEC:
   - A) predicts the type of producible hydrocarbons in the reservoir.
   - B) differentiates between productive and non-productive zones.
   - C) makes a distinction between indigenous hydrocarbons and formation contamination with oil-base drilling fluids (if they are different).
     - a) A "refined" oil has a different grouping than a live crude.
     - b) If a difference in carbon count distribution is noticed when overlaying the oil plot of the mud with the oil plot of the sample, this indicates the presence of an additional hydrocarbon.
       1. unrefined oil: a broad, even hydrocarbon distribution
       2. refined oil: a narrow hydrocarbon distribution
   - D) "fingerprints" oils so that they can be distinguished from each other.
   - E) distinguishes productive oil zones from depleted zones.
     - a) Calculate and plot 5 hydrocarbon indexes from samples.
     - b) These indexes are used to:
       1. correlate formation oils.
       2. determine maturity levels.
       3. help define shifted or altered water contacts.
     - c) Indexes
       1. **nC15 ÷ Total Crude**
          - A. indicates maturity and type of production
       2. **Total nC ÷ Total Crude**
          - A. same as 1. and shows total amount of saturated hydrocarbons
       3. Carbon Preference Index (CPI)
          - A. mature: value of 1 or less
          - B. immature: value of 2 or greater
       4. **[nC17 + nC18] ÷ [Pr + Ph]**
          - A. may indicate shifted or altered oil/water contacts in depleted zones or identify depleted zones outright
       5. **Pristane ÷ Phytane**
          - A. the more mature samples have high values
     - d) "n" refers to the "normals" or the saturated hydrocarbons in the samples.
       1. high peaks in a bar graph
     - e) The more biogradation an oil undergoes, the more unsaturated or aromatic it becomes.
       1. Generally speaking, the more aromatics a sample has, the lower its chances are of producing oil in commercial quantities.
          - A. a function of geologic province
          - B. may hold true in the U.S. Gulf Coast but not hold true in California
       2. "Maturity" refers to thermal maturity.
          - A. A thermally immature oil:
            - a. on the Gulf Coast:
              - 1] might produce from a shallow zone.
              - 2] probably will not produce from a deeper zone.
            - b. in California:
              - 1] will produce very well from any depth.

3. A prediction can sometimes be made regarding the outcome of the calculated values for the Indexes according to the table below (in the order presented).

Index	Condensate	Oil	Immature Oil
(1)	0.12	0.34	0.22
(2)	0.4	0.54	0.26
(3)	1.06	1.01	0.98
(4)	1.69	1.42	1.15
(5)	2.95	2.43	1.04
API Gravity	> 50	30 - 40	20 - 30

I- SPECIAL CORE ANALYSIS

a- Static Tests

1) Rock Compressibility
2) Permeability and Porosity vs. Net Overburden Pressure
3) Wettability Determinations
4) Electrical Properties
   A) Formation Factor vs. Porosity
   B) Resistivity Index vs. Water Saturation
5) Acoustic Velocity
6) Grain Density
7) Capillary Pressure
   A) Restored Technique
   B) Centrifugal Technique
   C) Mercury Injection Technique

b- Dynamic Tests

1) Liquid Permeability
2) Relative Permeability
   A) Gas-Oil
      a) with connate water
      b) no connate water
   B) Gas-Water
      a) drainage
      b) imbibition
   C) Water-Oil
      a) steady state
      b) non-steady state
3) Thermal Recovery
   A) Hot Water Flood
   B) Steam Flood
   C) In Situ Combustion
4) Gas Storage Caprock Evaluation
   A) permeabilities to 10^{-6} millidarcies
   B) threshold pressure at which gas penetrates caprock
5) Residual Gas (after water encroachment)
6) Water Flood Evaluations
   A) Fresh Core
   B) Restored Samples
   C) Room Condition Tests
   D) Reservoir Condition Tests

19 - ABANDONMENT AFTER DRILLING

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A- AFTER DRILLING A DRY HOLE { 92 }

a- Time Limit

1) A Regulatory Authority usually imposes a time limit by which a well must be plugged.
2) Check the limit each time because the rules change occasionally.
   A) For example, Texas is currently 90 days.

b- Notification

1) After deciding to plug the well, inform the:
   A) Landowner.
   B) Offset Operators.
   C) appropriate Regulatory Authority.
2) Give the following information to the Regulatory Authority.
   A) Operator name
   B) Well name
   C) Well number
   D) Location
   E) API number
   F) Permit number
      a) date permit was issued
   G) Depth of usable-quality water
      a) date usable-quality water was determined
   H) Surface casing depth
      a) depth of other strings
   I) Cement top in all strings
   J) Recommended plugging procedure
      a) surface pipe [**D-**]
      b) intermediate pipe [**E-**]
3) Receive approval.
   A) Get the name of the Official who gives the authorization.
   B) How is approval given?
      a) phone
      b) fax
      c) letter
4) Ask if you should wait for their Representative to arrive on location before beginning the plugging operations.
5) An Operator's Representative must be on location while plugging.
6) Use only Regulatory Authority-approved companies for plugging.
7) After plugging is completed, submit a plugging report. [**Chapter 20**]

c- Bids

1) Take bids:
   A) to plug the well.
      a) usually the same Cement Company that set surface and/or intermediate pipe
   B) for the heavy mud, from individuals interested in buying it.
   C) to do mud disposal and backfill the pits.
      a) See lease preparation. [**Volume 1, Chapter 5**]
   D) for the equipment and all of the tubulars.
   E) to have everything hauled off.
   F) to remove the pad and the road materials if required by the lease.
      a) to buy the materials.
   G) to remove the cattle guards and close all lease entrances.

B- CEMENT PLUGS

a- Successful Plugs

1) Plugs are under increased scrutiny as environmental concerns are heightened.
2) Plugs have to withstand being tagged (tamped, weight put on it).
3) Successful plugs can be set if:
   A) the slurry is properly designed.
      a) The slurry should consist of only cement and retarder.
      b) Silica sand should be used (i.e. - no other additives).
   B) the slurry is properly displaced.
   C) adequate volumes are used.
   D) the same care is used to design and set the plugs as would be used to design and place casing slurries.

b- Reasons for Plug Failure {70}

1) Cement interaction with mud
2) No pre-job preparation
3) Using improper cementing practices
4) Violating displacement mechanics
5) Using incorrect temperatures when designing slurry
6) Plug migration
   A) Avoid this problem by using:
      a) a bridge plug.
      b) a cement basket.
      c) spotting a bentonite or reactive silicate pill below the plug.
      d) proper plug balancing methods.
   B) Use sufficient spacer volume.
      a) Inadequate spacer volume results in incomplete mud removal because of poor cement/mud separation.
   C) Correctly estimate the hole volume.
      a) prevents:
         1. plug contamination
         2. weakening of the plug

C- PLUG DESIGN

a- Common Casing Sizes vs. Approximate Volumes and Displacements

1) For example:
   A) in $5^1/_2$ inch casing, one sack of cement mixed to a 1.18 yield will fill up 8.6 feet of casing.
   B) in $4^1/_2$ inch casing, one barrel will fill up 61.5 feet of casing.
   C) in $7^5/_8$ inch casing, it takes 47.1 barrels to fill up 1,000 feet of casing.

Casing Size	Cement Mixed to a 1.18 yield	Casing Capacity	
in	ft/sx	ft/bbl	bbl/1,000'
$2^7/_8$	36.3	172.8	5.8
$4^1/_2$	12.9	61.5	16.2
5	10.7	49.5	20.2
$5^1/_2$	8.6	41.0	24.4
6	7.1	33.7	29.6
7	5.2	24.7	48.4
$7^5/_8$	4.5	21.2	47.1
$8^5/_8$	3.4	16.0	62.4
$9^5/_8$	2.7	12.7	78.7
$10^3/_4$	2.1	9.9	100.9
13	1.4	6.7	148.4
16	0.9	4.4	225.9

b- Cement Plug Balancing Calculations

1) Determine the hole volume (in cubic feet) that the open hole/cased hole plug is to occupy. [**Chapter 14, C-**]
2) Determine the number of sacks of cement needed to occupy the volume (in cubic feet) of the open hole. [**Chapter 14, C-**]
3) Determine the number of barrels of mixing water required. [**Chapter 14, C-**]
4) Determine the height of the cement, with drill pipe in the hole, when the plug is balanced.
   A) Plug Balancing Formula

      $$H = V \div [A + Ct]$$

      a) Where:
         H = height of the balanced cement column in feet
         V = cement volume in feet^3
         A = annular volume in feet^3/foot
         Ct = workstring capacity in feet^3/foot

5) Determine the number of barrels of spacer/water needed to pump behind the plug in order to balance with the spacer/water ahead of the plug.

   bbls of spacer/water behind = bbls of spacer/water ahead x [(bbls/ft in the drill pipe) ÷ (bbls/ft in the annulus)]

6) Determine the height of the spacer top, with drill pipe in the hole, when the plug is balanced.

   spacer top height = hole capacity in feet/barrel x total fluid pumped when spotting the plug

D- PLUGGING WELLS WITH SURFACE PIPE

a- Insufficient Surface Pipe

1) When insufficient surface pipe is set to protect usable-quality water, a plug should be placed starting 50 feet below the base of the water and extending 50 feet above the top.
   A) This plug must be tagged with drill pipe.
2) An additional plug must be set across the surface casing shoe.
   A) This plug must be 100 feet long and straddle the shoe.

b- Sufficient Surface Pipe

1) Set a plug across the surface casing shoe.
   A) This plug must be 100 feet long and straddle the shoe.

c- Surface Pipe Set Deeper than Required

1) If the surface pipe has been placed 200 feet deeper than the Texas Department of Water Resources (TDWR) depth (Texas only):
   A) place an additional plug (a minimum of 100 feet in length) inside the casing across the base of the fresh water depth (TDWR depth).
   B) start 50 feet below the base of the TDWR depth and extend 50 feet above the top of the TDWR depth.

E- PLUGGING WELLS WITH INTERMEDIATE PIPE

a- Insufficient Cement

1) If the cement does not cover all of the TDWR zones and if pipe will not be pulled:
   A) perforate at the required depths.
   B) squeeze.

b- Sufficient Cement

1) If sufficient cement was used to cover all of the TDWR zones, use (minimum) a 100 foot plug inside the casing.
2) Place it starting 50 feet below the base and extending 50 feet above the top of the TDWR zones.

c- General Guidelines

1) Usually, set a retainer at the bottom of the intermediate string.
2) Pump the first plug below it.
3) Leave some cement on top of the retainer.

F- GENERAL PLUGGING SEQUENCE

a- Checklist

1) Do you want to leave anything for the Landowner?
   A) fencing materials
   B) road materials
   C) cattle guards
   D) water well
2) Pits
   A) Tell the Landowner that you intend to wait until the pit contents dry out before backfilling them.
   B) Should the pits be fenced off while waiting?
   C) Does the O&GML authorize the spreading of the drilling mud?
   D) If the chlorides are too high, is a permit required from the Regulatory Authorities to allow land farming of the contents?
3) Location
   A) If no one bids to buy the road and pad materials, find somewhere to store them.
   B) Does the location have to be leveled and/or plowed up?
   C) Does the O&GML require that grass be planted?
4) Make arrangements to:
   A) remove the cattle guards.
   B) close all lease entrances.
5) Can anything be salvaged from the well?
   A) If heavy mud was used on bottom, displace into a holding tank.
      a) Keep 9.5 ppg mud in the normal frac gradient depths.
   B) A cement plug separates the heavy environment from the lightweight environment.
   C) Non-drillable "junk" cannot usually be left in the well without prior approval by the Regulatory Authorities.
6) How deep is the fresh water?
7) Read the calipered hole volume from the Open Hole Log.
8) Drill Pipe
   A) What size drill pipe will be used?
   B) What type of connections does the drill pipe have?
9) Release the Mud Loggers.
   A) Arrange to have all sacked mud picked up.
10) Identify who should be used for plugging.
    A) usually the same Cement Company that set pipe
11) Put them on stand-by with the below listed information.
    A) *Exact, detailed directions to the location*
    B) Lock combinations in sequence
    C) Pipe size
       a) casing
       b) drill pipe
    D) Plugs
       a) number required
       b) at what depths
       c) length of each plug
    E) number of sacks of cement needed for the plugs
12) Review the basic requirements (e.g. - Texas).
    A) Tag all open hole plugs.
    B) The fluid between the plugs must be at least 9.5 ppg.
    C) Does the displacement agree with the cement calculations?

D) Deepest Plug
   a) 100 foot plug, plus 10% for every 1,000 feet of depth, on bottom.

E) Fresh Water Plug(s)
   a) Straddle the fresh water depth with a minimum 100 foot plug.
   b) Start 50 feet below the base of the TDWR depth and extend 50 feet above the top of the TDWR depth.

F) Surface Plug
   a) 30 foot plug at the surface.

b- Typical Procedure

1) Run a plug pipe to the desired depth.
2) Attach a swedge or valve to the drill pipe.
3) Connect lines to the:
   A) swedge or valve.
   B) pump truck.
4) Pump 5 barrels of fresh water ahead.
5) Mix the cement.
6) Displace the slurry by:
   A) using balanced plugs.
   B) pumping some fresh water behind to prevent mud and cement contact that will:
      a) contaminate the mud.
      b) cause extra expense during location clean-up.
7) Disconnect the swedge or valve.
   A) Pull the drill pipe up to the next setting depth.
8) Repeat 1) through 7) until all of the plugs are set.

c- After Plugging

1) Dig out the cellar.
   A) Cut and weld a plate on the surface pipe.
2) Cut off all casing a minimum of 3 feet below ground level.
3) Release the drilling rig only after they have:
   A) filled in the rat hole and the mouse hole.
   B) put all the trash in either:
      a) barrels.
      b) the trash pit.
      c) the burn pit.
      d) piled in one area.

G- MUD DISPOSAL

a- Land farm on the Same Lease

1) Regulatory Authority approval required.
   A) Allowed only if:
      a) the Landowner gives approval in writing.
      b) it does not violate the terms of the lease.
      c) the chloride concentration is 3,000 ppm or less (Texas).
         1. If greater that 3,000 ppm, go to **c-**.

b- Land farm on Another Lease

1) Regulatory Authority approval required.
   A) Allowed only if:
      a) the Landowner gives approval in writing.
      b) the chloride concentration is 3,000 ppm or less (Texas).
         1. If greater that 3,000 ppm, go to **c-**.
2) An Operator may apply for a "minor permit" to landfarm drilling fluid off of the lease where it is generated (Texas).
   A) The application should include: { 93, 94 }
      a) the Operator's name and address.
      b) the location of the lease including well number, field, and county where the drilling fluid was generated.

c) a description of the proposed site by Owner, tract size, and location.
d) written directions for finding the site.
e) a map or plat of the disposal site showing:
   1. all major waterways in the area.
   2. all drainage ditches nearby.
   3. a general description of the contour of the disposal site, including any on-site water courses or drainage-ways.
f) written permission from the Landowner to use his property for land farming the drilling fluid.
   1. The Landowner may indicate his consent by signing the Operator's application.
g) a description of the drilling fluid to be land farmed.
   1. chloride concentration
   2. fluid volume
h) the name and address of the Service Company that will actually land farm the drilling fluid.

B) The application must be signed by the Operator's Representative responsible for making sure that the drilling fluid is handled properly.

c- Haul Off-site

1) Drilling fluid cannot be land farmed on or off of the lease unless the chloride concentration of the drilling fluid is low enough.
   A) usually 3,000 ppm or less (Texas)
2) Remove the mud to a disposal facility.

d- Salvage

1) Sell it to an authorized hauler.

e- Disposal Down the Casing/Annulus of the Well

1) Regulatory Authority approval required.
2) Supply the following information.
   A) Operator name and address
   B) Lease name, well number, field, and county of the well into which the drilling fluid will be injected
   C) Depth of the usable-quality water
   D) Plans for disposal
      a) down the surface casing/intermediate pipe annulus
         1. dry hole
   E) Casing record of each string in the well, to include:
      a) depth
      b) size
      c) grade
      d) weight
      e) burst strength
      f) collapse strength
      g) cementing record
   F) Proposed maximum surface injection pressure
   G) Description of the fluid to be injected
      a) chloride concentration
      b) fluid volume
   H) Describe the methods used to protect the productive horizons.
   I) Statement to the effect that:
      a) all Offset Operators within one mile have been notified.
      b) none of the Operators in a) have any objections.
   J) Signature of the Operator or an authorized Representative

3) Considerations
   A) If the surface pipe was not set deep enough to protect the usable-quality water, the request will be denied.
   B) If the productive zones in the well are not protected against the potential encroachment of the disposed drilling mud, the request will be denied.
   C) The maximum authorized injection pressure will usually be limited to whichever is less:
      a) $^1/_2$ pound per foot of depth of the surface pipe.
      b) $^1/_2$ of the bursting strength of the surface pipe.

4) Associated Costs
   A) Bids should normally include:
      a) move in.
      b) rig up.
      c) disposal.
      d) backfill.
      e) rig down.
      f) move out.
   B) There will normally be some portion of the reserve pit that will be considered non-pumpable and left as residual to be buried when backfilling the pits.
   C) Equipment Required
      a) bulldozer with fuel and Operator
      b) mounted triplex pump
      c) mud tank
      d) shale shaker
      e) tractor with a high lift (re-lift/trash) pump
      f) hoses and lines
      g) pressure recorder

20 - REPORTS

TABLE OF CONTENTS

A- SPUD/SURFACE CASING REPORT

a- Time of Preparation

1) Usually written up the first day after surface pipe is set.

b- Report Format

1) Moved in and rigged up (*Drilling Contractor*) rig (#).
2) Spudded well at (*00:00 am/pm*) on (*date*).
3) Drilled (*size"*) hole to (*depth'*) at (*00:00 am/pm*).
4) Tripped drill pipe to condition the hole and the mud.
5) Pulled out of the hole and rigged up (*size"*) casing tools.
6) Ran (#) joints of (*type*)(*size"*)(*weight*) casing with (#) centralizers and (*float equipment*).
7) Casing cemented by (*Cement Company*).
   - A) Pumped (*# barrels: # sacks: volume in ft³*) of Class (*type*) cement with (*additives*).
   - B) Reciprocated pipe (#) feet while cementing.
   - C) Got (#) barrels of (*marginal/good*) returns at the surface.
   - D) Cement (*did/did not*) settle out.
     - a) Settle out was dealt with by either/or:
       1. filling with a load of pea gravel.
       2. topping out with (#) of sacks of Class (*type*) cement with (*additives*).
   - E) Used (*Cement Company*) and (*size"*) pipe for the top-out.
8) Bottom of casing at (*depth'*).
9) Waited on cement (#) hours.
10) Rigged up (*screw-on/weld-on*) Bradenhead flange, which took (#) hours.
11) Nippled up and pressure tested blank rams, choke manifold, and casing to (#) pounds.
12) Ran drill pipe with a (*size"*)(*type*) bit.
13) Pressure tested rams and Hydril to (#) pounds.
14) Costs of the Previous 24 Hours
   - A) Daily mud cost __________
   - B) Cumulative mud cost __________
   - C) Daily well cost __________
   - D) Cumulative well costs __________

B- DAILY REPORT { 95 }

a- Time of Preparation

1) Every morning, detailing information on the work done since yesterday's morning report.

b- Report Format

1) General

A) Date ____________________
B) Operator name ____________________
C) Lease name ____________________
D) Well # ____________________
E) Hole made since previous report __________
F) Current depth __________
G) Proposed total depth __________
H) Estimated days to finish the job __________
I) Day # __________

2) Time Breakdown (number of hours involved in each activity)

_____rig up	_____trip
_____rig down	_____cut drilling line
_____weld casinghead	_____run pipe
_____weld conductor	_____wait on cement
_____drill rat/mouse holes	_____nipple up/test BOPs
_____drill float	_____test casing
_____drilling	_____survey
_____ream	_____log
_____core	_____wireline test
_____milling	_____wireline core
_____circulate	_____laydown drill pipe
_____heaving shale	_____lost returns
_____work pipe	_____wait on orders
_____displace mud	_____fishing
_____rig service	_____drop slips
_____cut casing	_____clean tank

3) Mud

________pump size	________mud weight
________pump pressure	________viscosity
________pump efficiency	________water loss
________pump strokes	________gels
________pump cost	________sand
________pump maintenance	________pH
________pump repair	________oil
________annular volume drill pipe	________solids
________annular volume drill collar	________plastic viscosity
________daily mud costs	________yield point
________cumulative mud costs	________chlorides

4) Bit

_________type	_________depth put in hole
_________rpm	_________depth pulled out of hole
_________condition	_________hole made
_________weight on bit	

5) Rental Equipment

A) List:

a) all equipment.

b) daily rental charges.

c) cumulative costs.

6) Present Operation

A) Write a short description of the activity at report time.

7) Diesel Fuel (in gallons)

__________on hand __________used

C- CEMENTING REPORT

a- Time of Preparation

1) After each string of casing is cemented.

b- Report Format

1) Casing

A) Ran (*size"*) casing as follows: pipe (*# joints, size, type, weight, grade*) for a total length minus threads of (#) feet.

	number of feet
a) float shoe	____________
(#) joints of (*size,type,weight,grade*)	____________
b) float collar	____________
(#) joints of (*size,type,weight,grade*)	____________
(#) joints of (*size,type,weight,grade*)	____________
c) diverter tool	____________
(#) joints of (*size,type,lighter wt,grade*)	____________
(#) joints of (*size,type,heavier wt,grade*)	____________
(#) joints of (*size,type,weight,higher grd*)	____________
Total footage	____________

B) Landed casing at (*depth'*) measured from the (*derrick floor/ kelly bushing/ground level*).

C) Rigged up (*Cement Company*).

D) First Stage

a) Cemented the first stage with (#) sacks of Class (*type*) cement with (*additives*) mixed at (#) pounds per gallon.

1. Yield was (#) ft^3/sack.

b) Bumped the plug and pressured to (#) pounds.

c) Dropped a bomb to open the diverter tool.

E) Second Stage

a) Cemented the second stage with (#) sacks of Class (*type*) cement with (*additives*) mixed at (#) pounds per gallon.

F) Nippled up "B" section and tested to (#) pounds.

G) Pipe (*was/was not*)(*rotated/reciprocated*)(#) feet while cementing.

2) Liner

A) Rigged up the (*liner size"*) elevators and tongs.

B) Went in the hole with:

a) (*size"*)(*type*) guide/float shoe.

b) (#) joints of (*type*) pipe.

c) (*type*) plug landing collar.

d) (#) joints of (*type*) pipe.

e) (*size"*)(*type*) liner hanger.

f) (#) joints of (*type*) work string.

C) Circulated and conditioned the mud.

D) Hung the liner off at (*depth'*) with (#) pounds of weight.

a) Picked up (#) inches to verify that the:

1. liner hanger had set.
2. liner was hung off.

E) Rigged up (*Cement Company*).

a) Pumped (#) barrels spacer at (#) barrels per minute and (#) pounds pump pressure.

b) Mixed (#) sacks of Class (*type*) cement and (*amount*)(*type*) additives.

c) Slurry volume: (#) barrels

d) Cement weight: (#) pounds per gallon

e) Cement yield: (#) ft^3/sack

f) Slurry was pumped at (#) barrels per minute and (#) pounds pump pressure.

g) Bumped the plug at (*00:00 am/pm*) with (#) pounds over pump pressure.

h) Plug (*held/did not hold*) OK.

i) Stung out of the liner hanger and (*had/did not have*) flow back due to U-tube of the cement.

F) Pulled out of the hole with (#) joints and reversed out.

G) Recovered (#) barrels of cement.

H) Pulled out of the hole.

I) Went in the hole with a (*size"*) rock bit and waited on cement (#) hours.

J) Tagged cement at (*depth'*) and drilled (*hard/soft*) cement to (*depth'/ the top of the liner*).

K) Circulated the hole clean and pulled out of the hole.

L) Went in the hole with a test tool and a differential test liner top.

M) Picked up the (*liner size"*) bit and (#) joints of (*liner size"*) (*rental*) work string.

N) Went in the hole and tagged cement at the top of the liner.

a) Drilled (*hard/soft*) cement until broke through at (*depth'*).

O) Tested the liner top to (#) pounds.

a) (*Held/did not hold*) OK.

b) If did not hold OK:

1. broke down at (#) pounds.
2. could pump-in at (#) barrels per minute and (#) pounds pump pressure.

P) Ran in the hole to plug back total depth (*found at* (#) *feet*).

D- DRILLING BREAK/SHOW REPORT

a- Time of Preparation

1) Usually after each drilling break or show, depending on company policy.

b- Report Format

1) Interval

A) from (*depth'*) to (*depth'*)

2) Drilling Rate

A) Above Interval ____________

B) Through Interval ____________

C) Below Interval ____________

3) Mud/Gas Chromatograph Data

	Before	**During**	**After**
Total Units	______	______	______
C1 units	______	______	______
C2 units	______	______	______
C3 units	______	______	______
C4 units	______	______	______
Chlorides	______	______	______

A) Type of Increase
- a) gradual/sharp

B) Gas Variation Within the Zone
- a) steady/erratic
- b) increasing/decreasing

C) Fluorescence
- a) none/poor/fair/good
- b) color

D) Cut
- a) none/poor/fair/good
- b) streaming/slow/moderate/fast

E) Stain
- a) none/poor/fair/good
- b) live/dead
- c) residue/even/spotty
- d) light/dark

F) Porosity
- a) poor/fair/good

G) Lithology
- a) Describe

H) Remarks
- a) Circulate how long?

I) Mud Properties
- a) Mud cut from (#) to (#) pounds per gallon (if applicable).
- b) If mud cut, how long did the gas stay in the mud?

E- KICK REPORT

a- Time of Preparation

1) After each kick.

b- Report Format

1) Circulated out the kick for (#) hours at (*depth'*).
2) Estimated bottom-hole pressure at the zone was (#) pounds.
3) The well kicked while (*activity*) at (*depth'*) with (#) pound mud.
4) Shut the well in with (#) pounds on the drill pipe and (#) pounds on the casing.
5) Built the mud weight to (#) pounds per gallon.
6) Circulated kill weight mud through the bit at (*00:00 am/pm*) and to the surface at (*00:00 am/pm*).
7) Maximum surface pressure while circulating out the kick was (#) pounds.
8) The kill sheet (*was/was not*) used.
9) Started back to (*activity*) at (*00:00 am/pm*).

F- PLUG AFTER DRILLING REPORT

a- Time of Preparation

1) After running an Open Hole Log, evaluating the results, and deciding that it is a dry hole.

b- Report Format

1) Laid down the drill pipe (except plugging pipe).
2) Went in the hole open-ended to (*depth'*).
3) Rigged up by (*Cement Company*).
4) Spotted (e.g. - in-out/open hole/surface) plugs at the following intervals:
   A) (*length'*) (*type*) plug from (*depth'*) to (*depth'*).
   B) (*length'*) (*type*) plug at the surface.
   C) Note: use a retainer if protection pipe was used or if the depth of usable quality water is covered by surface pipe.
5) Dug out the cellar.
6) Nippled down the blow-out preventers.
7) Cut the Bradenhead flange (*3/#*) feet below ground level.
8) Welded a plate over the casing.
9) Cleaned out the tanks.
10) Released the rig at (*00:00 am/pm*).

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