Types of Well Completion Designs

Lecture 4

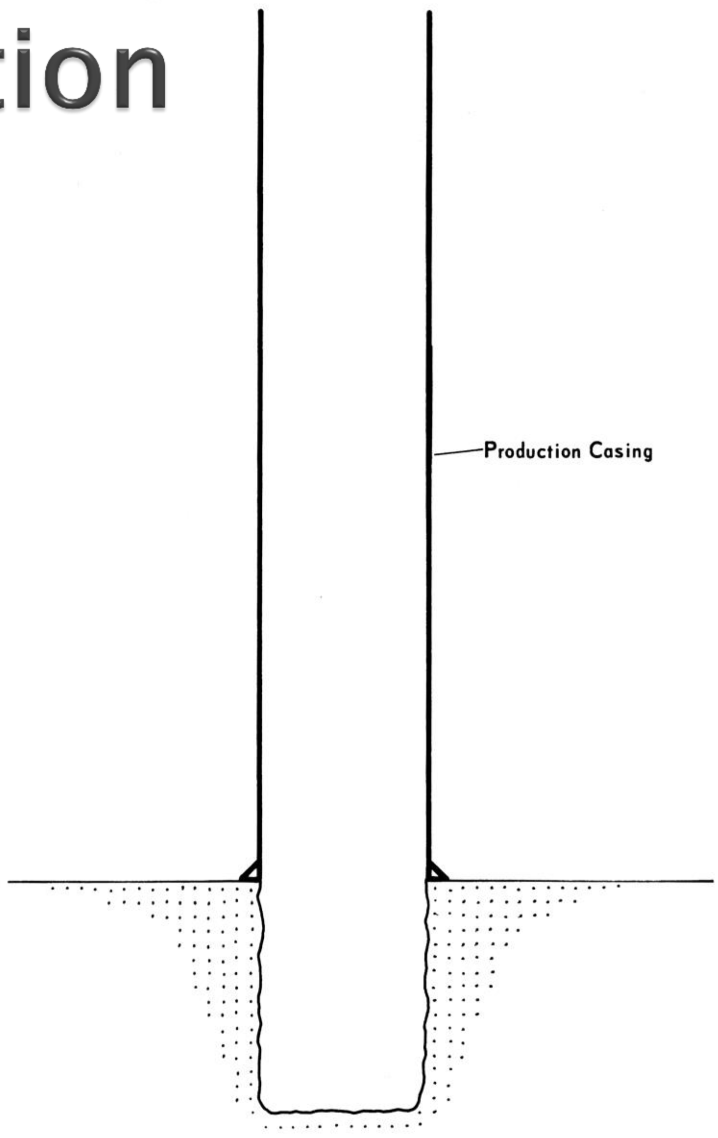
Completion Classifications

- There are a number of way of describing or 'classifying' completions
  - Location – land, subsea, platform, etc.
  - Basic design of the **lower completion** – open hole, cased & perforated, slotted liner, gravel pack
  - Lift requirements – selective for flowing well; rod pump or gas lift (etc) for lifted well
  - Geometry – vertical, deviated, horizontal, multilateral
  - Control – intelligent well
  - Number of tubing strings – single, dual

Openhole Completion

The openhole method call for production casing to be set above the zone of interest and prior to drilling same.

The well is completed with the producing interval open to the wellbore.



OPEN HOLE COMPLETION

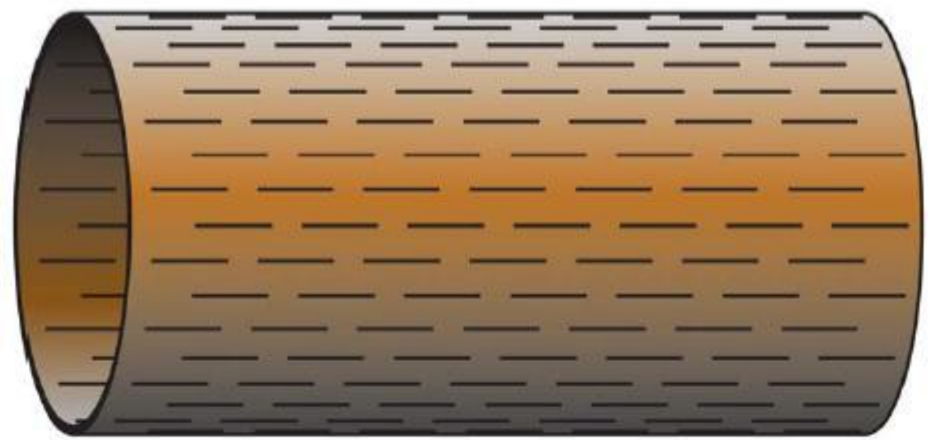
Openhole Completion

- Advantages
  - Elimination of perforating expense
  - Maximum wellbore diameter opposite pay
  - Easy to deepen well at a later time
  - Easily converted to a screen and liner or perforated liner completion
  - Depending on skin value, openhole completions theoretically provide ideal inflow capability

- Disadvantages
  - Excessive gas or water production difficult to control
  - Must run production casing before drilling zone
  - Producing interval cannot be selectively stimulated or produced
  - Open hole section may require frequent cleanout

Predrilled or Preslotted Liners

- Stop gross hole collapse
- Allow zonal Isolation packers to be deployed within the reservoir completion for upfront or later isolation
- Allow the deployment of intervention tools strings such as production logs (PLTs). Interpreting such logs can be difficult in high-angle wells.



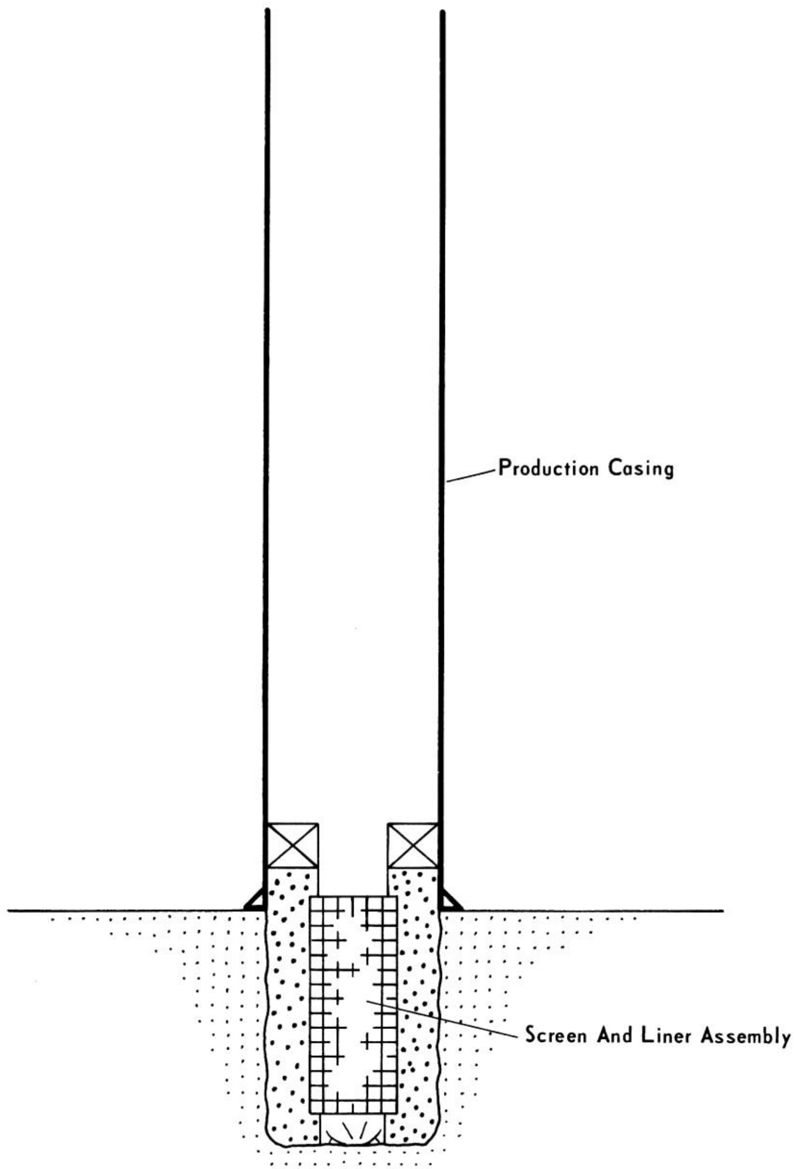
Predrilled/Slotted Liners

- Not normally a form of sand control as it is hard to make slots small enough to stop sand. If sufficiently small they are susceptible to plugging. Exceptions are use of slotted liners for steam assisted gravity drainage (SAGD).
- Pre-drilled liners are generally favored over pre-slotted as they have a much larger flow area and are stronger. Pressure drops through holes and plugging are far less a concern.
- A pre-drilled or pre-slotted liner can be installed with or without a washpipe and is similar to the deployment of a stand-alone screen.
- Without the requirement for sand control, the liner is usually installed in mud. The whole mud and filter cake is then produced through the liner.
- The washpipe is then relegated to contingency in case circulation is required to remove cuttings or other debris from the frong of the liner. It can also be used to set ECPs, displace solutions for the dissolution of the filter cake, etc.

Liner Completions

In a liner completion, casing is set above the zone and a liner is installed across the pay section.

The liner could be a screen or perforated pipe.



SCREEN AND LINER COMPLETION

Liner Completions

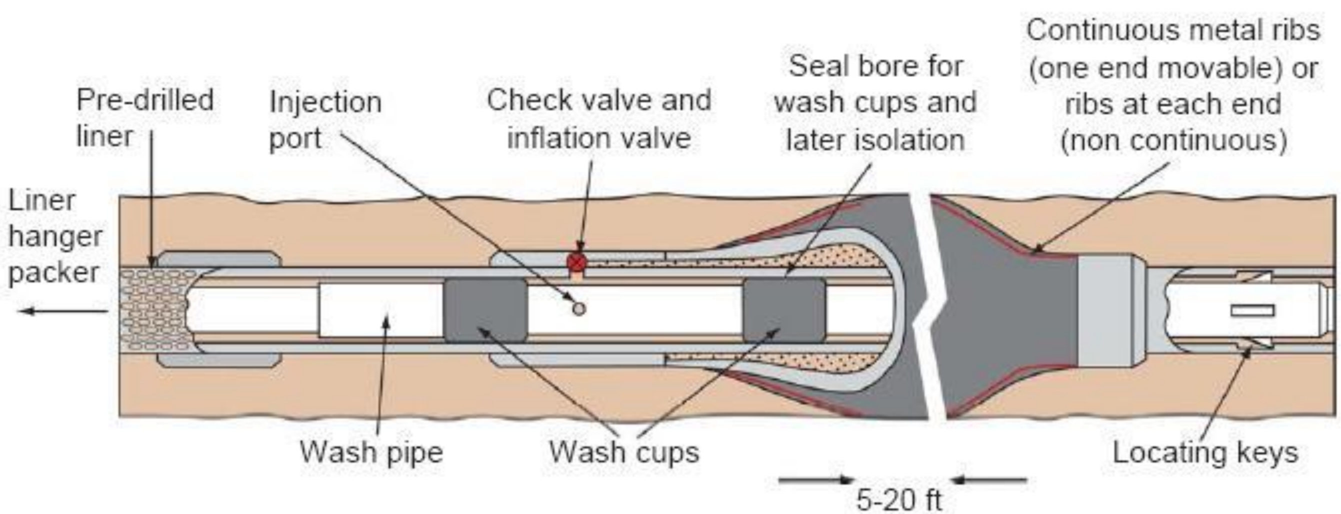
- Advantages
  - Same as openhole except that the design is adaptable to sand control techniques
  - Cleanout problems are avoided
- Disadvantages
  - Same as openhole (e.g. no selective production or stimulation over interval)
  - Well diameter across the pay is reduced and the well cannot be easily deepened

Standalone Screens (SAS)

- Used extensively throughout the world for sand control applications
- Low cost, easy to install but prone to plugging and other failures
- Can be wire-wrapped, pre-packed or premium screens (discussed later in sand control)

Zonal Isolation – ECP

- External Casing Packer (ECP) are inflatable packers used to isolate zones in openholes.
- The are run in pre-determined positions, often in conjunction with liner screens. Also run on tubing for stimulation of multiple zones.
- ECPs set from the bottom up via a washpipe. Used to be inflated with mud but can be inflated with cement, too.



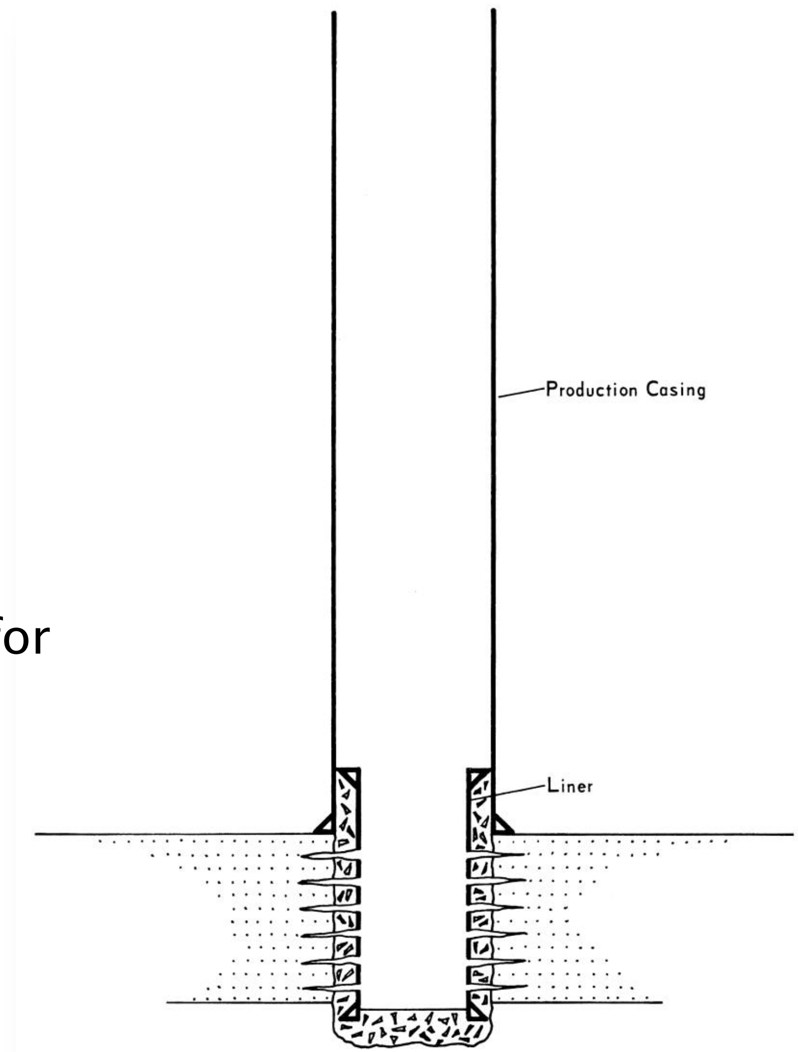
Swelleable Elastomer Packers

- Recent development in packers. The swelling takes advantage of a property of elastomers the previously was a limitation – swelling in the presence of oil or water.
- Main advantages over the ECP is cost and simplicity.
- With small clearances can hold up to 4000 psi.
- Swellable elastomers do take time to reach full expansion – normally around 7 days. So these packers are harder to test for pressure integrity than an ECP.

Cemented and Perforated Liner Completion

In a cemented liner the casing is set above the zone, the pay is drilled, and liner casing is cemented in place.

The liner is then selectively perforated for production.



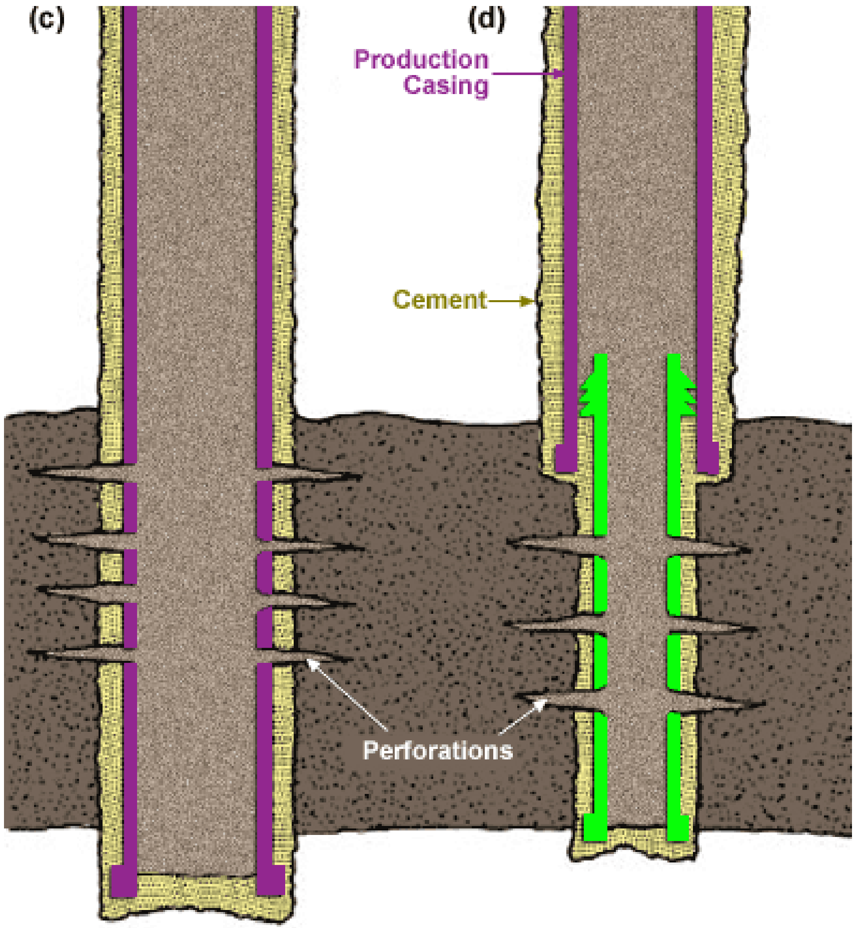
PERFORATED LINER COMPLETION

Cemented & Perforated Liner

- Advantages
  - Excessive gas or water production is more easily prevented or controlled
  - Formation can be selectively stimulated
  - Liner impedes sand influx, but adaptable to sand control techniques
  - Well can be easily deepened
- Disadvantages
  - Liner cementing can be more difficult than cementing primary casing
  - Additional cost of perforating, cementing, rig time

Cased and Perforated Completion

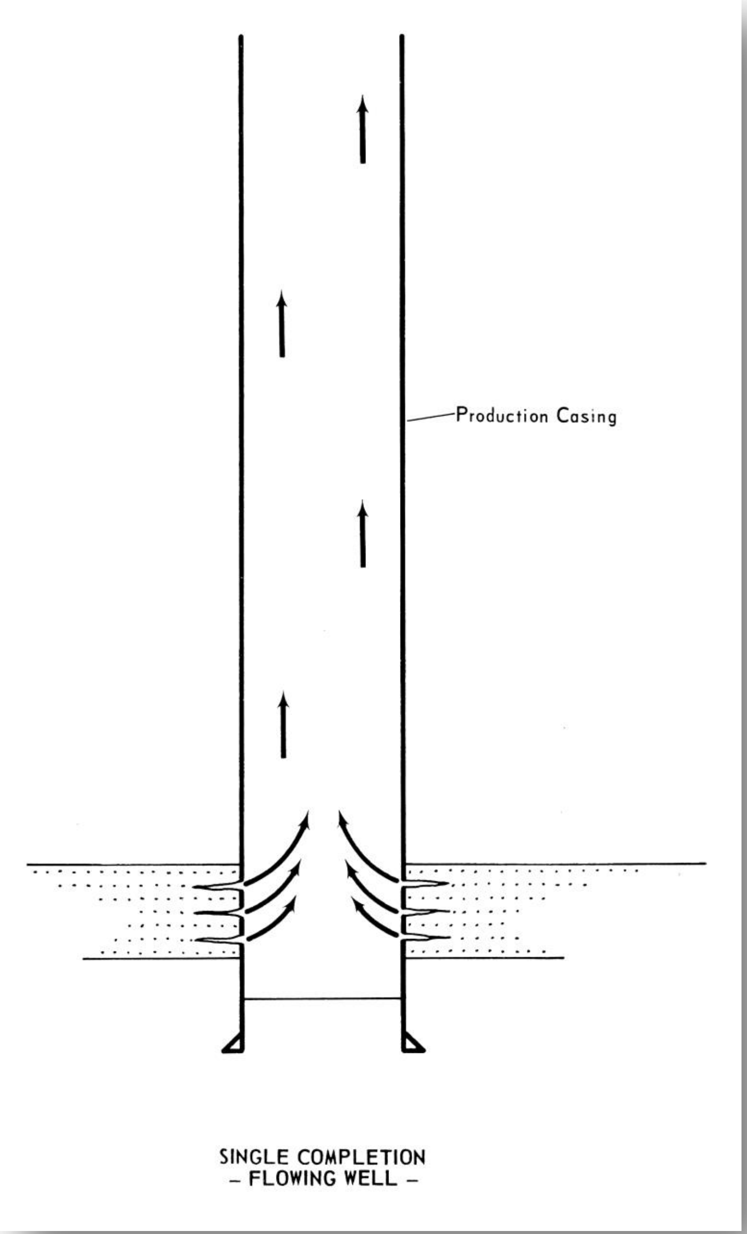
Production casing is cemented through the producing zone and the pay section is selectively completed.



Cased & Perforated Completions

- Advantages
  - Excessive gas or water more easily prevented or controlled
  - Formation can be selectively stimulated
  - Well can easily be deepened
  - Casing will impede some sand influx
  - Completion adaptable to sand control
  - Full diameter through the pay section
  - Logs available to pick casing point
  - Adaptable to all multiple completion configurations
  - Improved primary cementing (compared to liner)
  - Minimum rig time and logging expense
- Disadvantages
  - Perforating costs can be high
  - Log interpretation critical
  - Usually greater formation damage in pay section

Flowing Cased & Perforated Completion



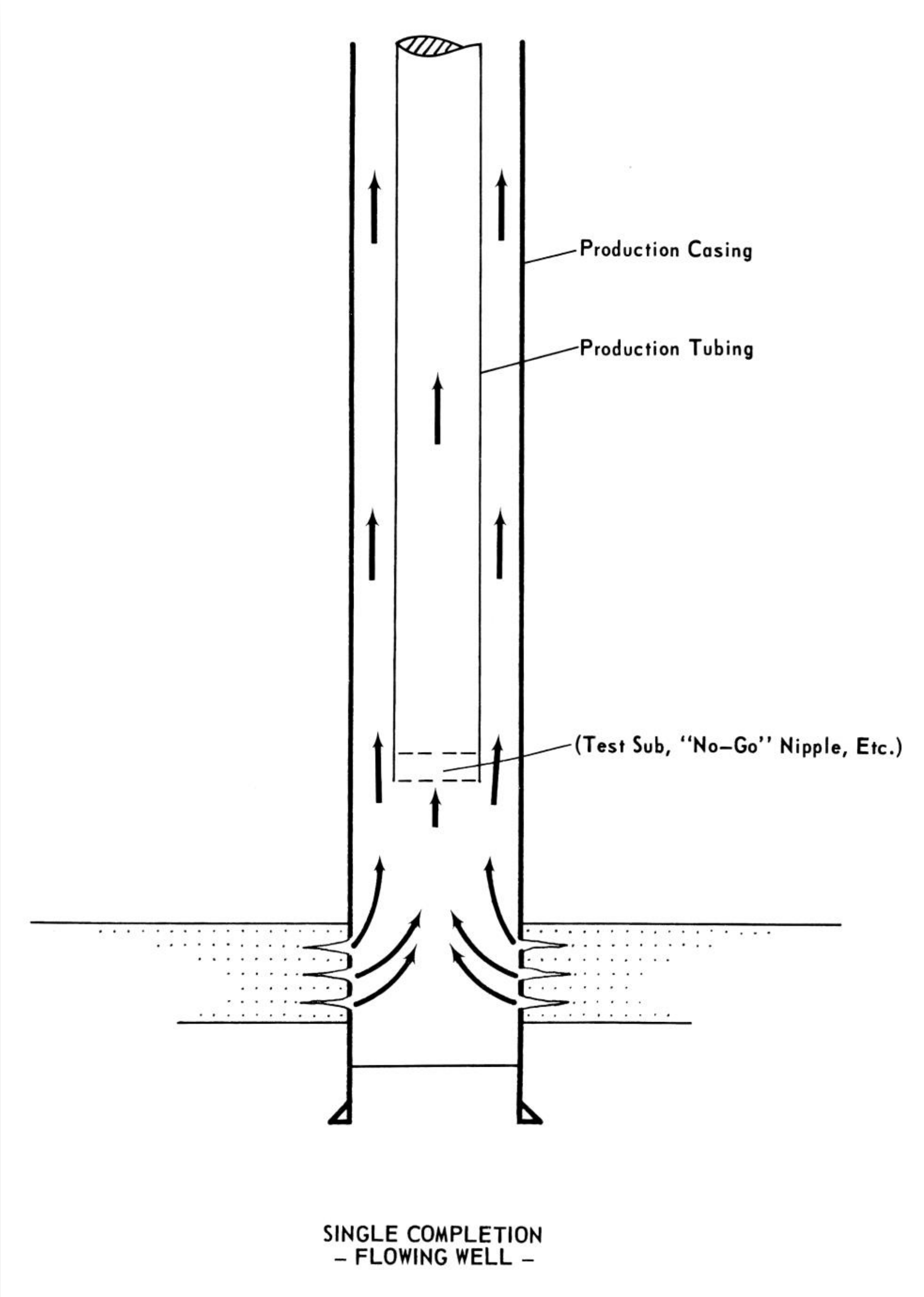
Flowing Well with Tubing

Flow up both the tubing and casing strings.

This design is only for wells capable of very high flowrates.

Landing nipple (no go) at bottom of tubing allows for tubing to be pressure tested

Tubing can be used as a kill string

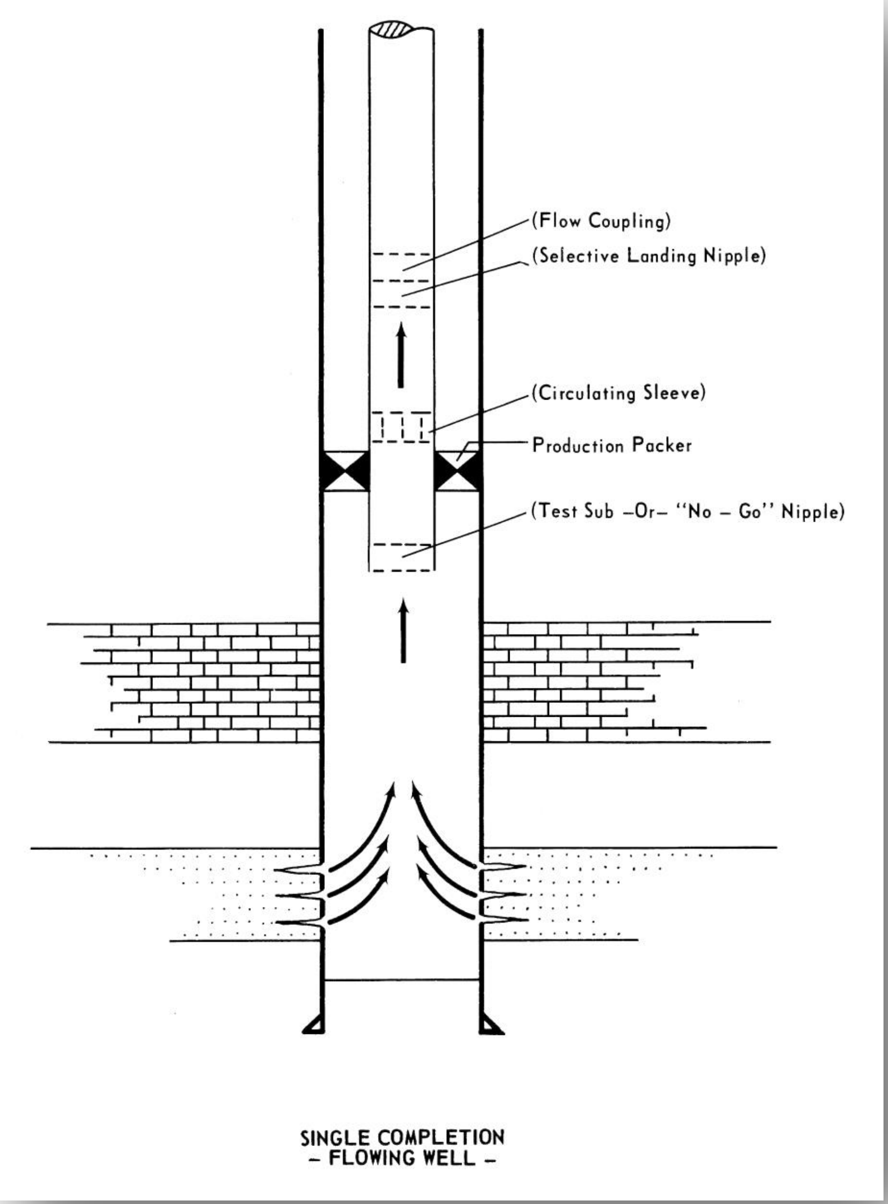


Flowing Single Completion

Both tubing and production packer are installed. Tubing restricts flow rates (compared to flowing up casing).

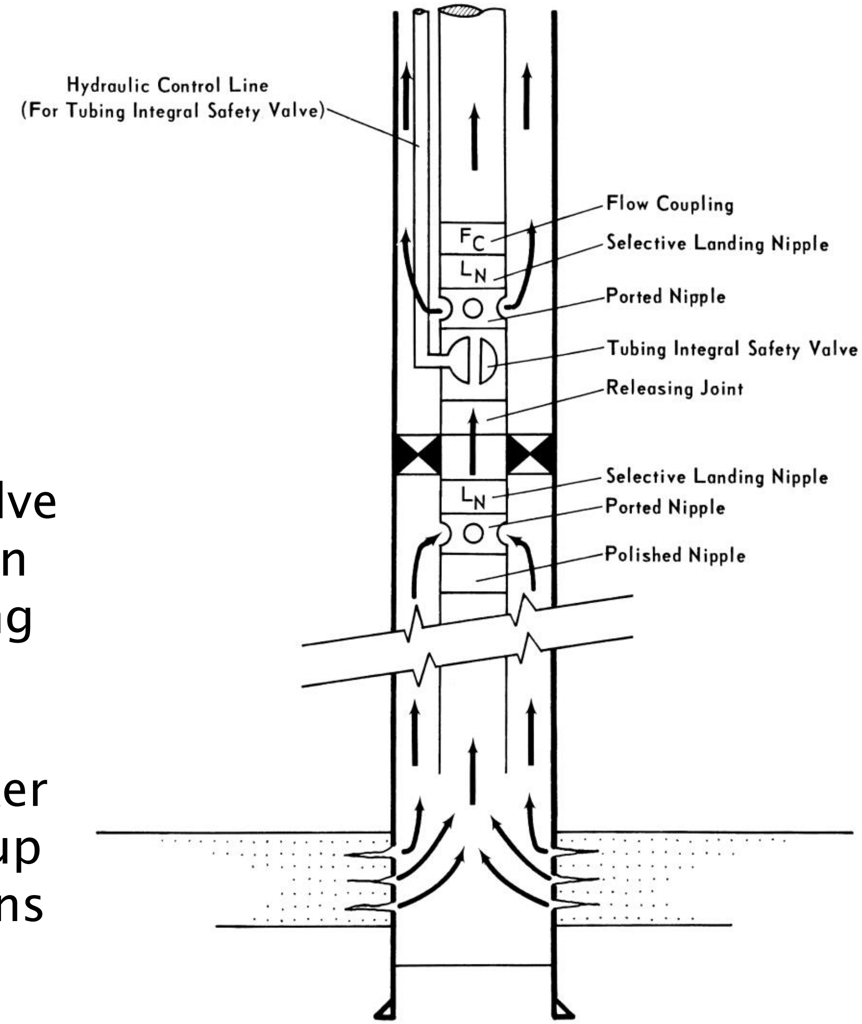
Packer installation may required for casing protection or barrier to flow. The ‘no go’ nipple can be used for a bottomhole choke, regulator or safety valve (storm choke).

The flow coupling is positioned to protect the landing nipple from erosion and the circulating sleeve is used to displace the tubing to a low density fluid after installation of the tree.



Single Completion – High Rate, Low Pressure

The production packer and safety valve are installed at some shallow depth in the well. Flow proceeds up the tubing and annulus to a point below the packer, enters the tubing through a ported nipple, flow through the packer and valve and then again continues up both the tubing and annulus by means of a second ported nipple.

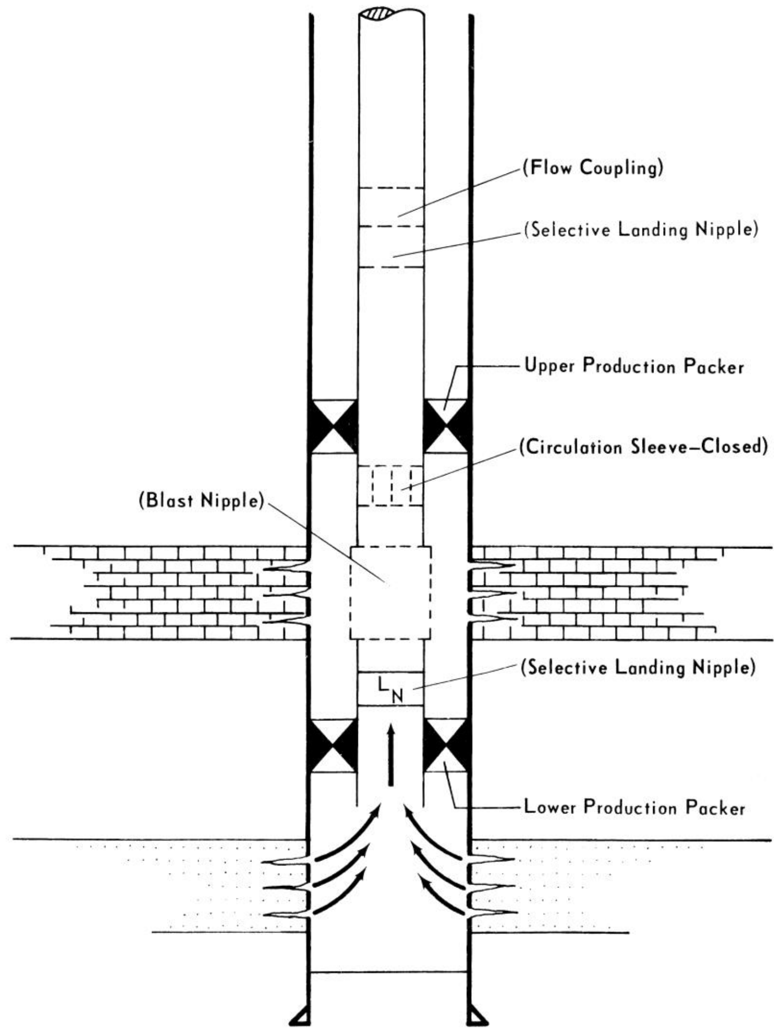


SINGLE COMPLETION – HIGH RATE, LOW PRESSURE FLOWING WELL

Single Selective Completion

The alternate zone is perforated on initial completion, but isolated between packers. It is placed on production when the lower zone is depleted by shifting the sliding sleeve or perforating the tubing opposite the zone

A blast joint is run opposite the zone between packers to delay tubing failure due to erosion



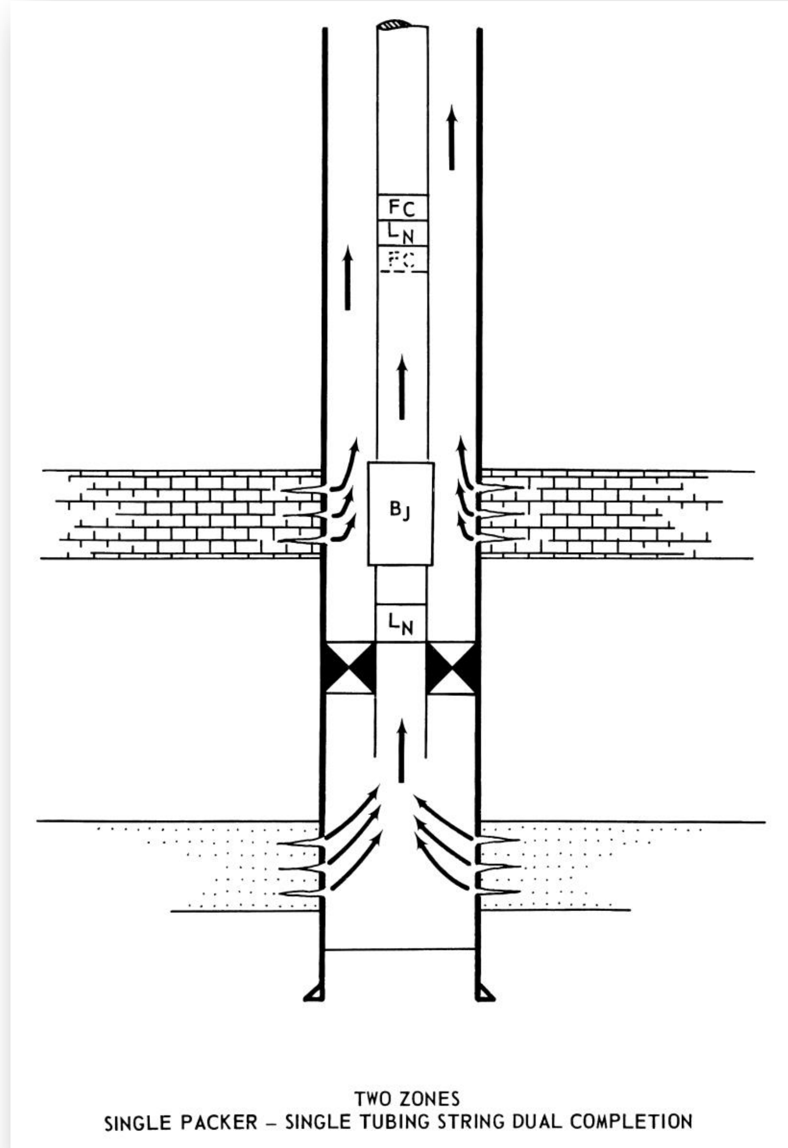
SINGLE WELL WITH ALTERNATE COMPLETION

Dual Zones with a Single String Completion

Most basic dual configuration. Production of the lower zone is up the tubing and upper zone flow is up the casing-tubing annulus.

Primary advantage is reduced cost.

Disadvantages are that it is difficult to artificially lift upper zone; casing is exposed to reservoir fluids; and the lower zone must be killed to workover the upper zone.

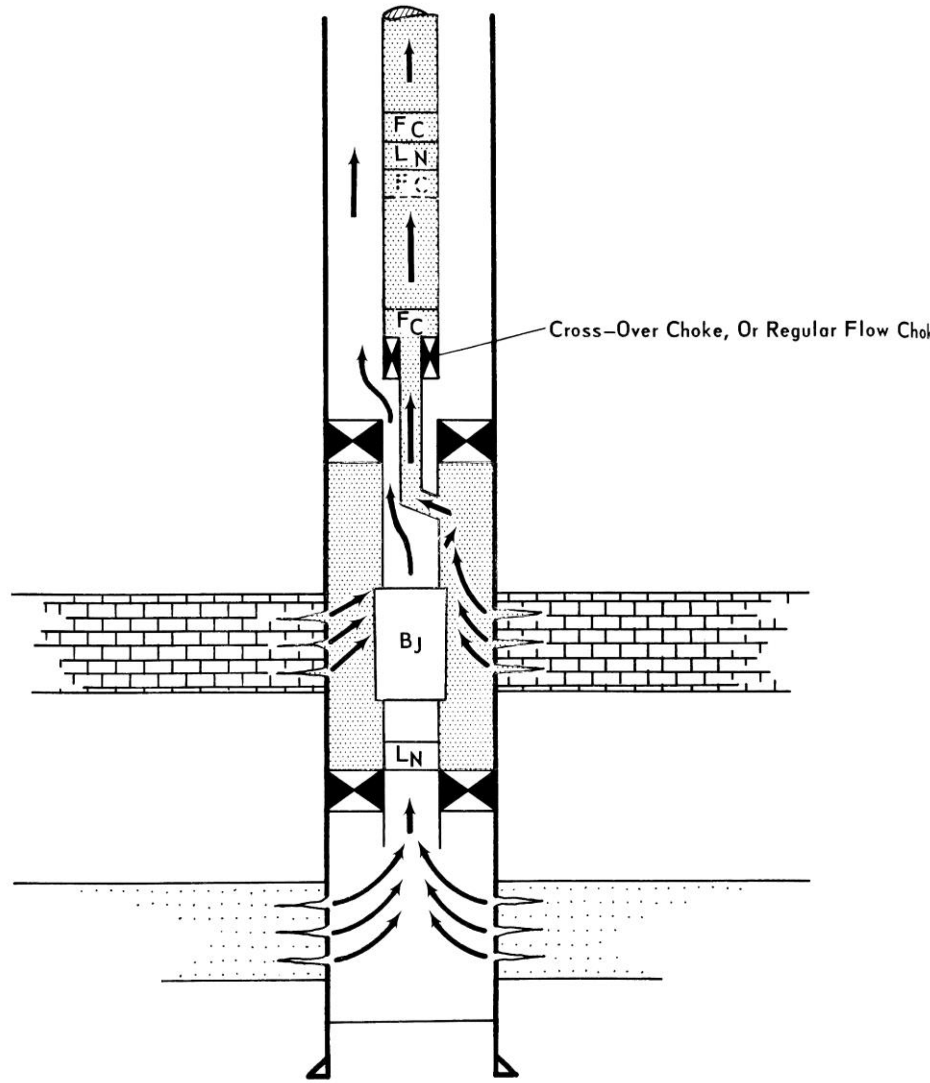


Two Zones Tubing/Casing Crossover

With this design it is possible to produce either zone up the tubing by utilization of a cross-over or regular flow choke.

This technique retains the disadvantages of casing exposure, plus inability to workover the upper zone without killing the lower zone.

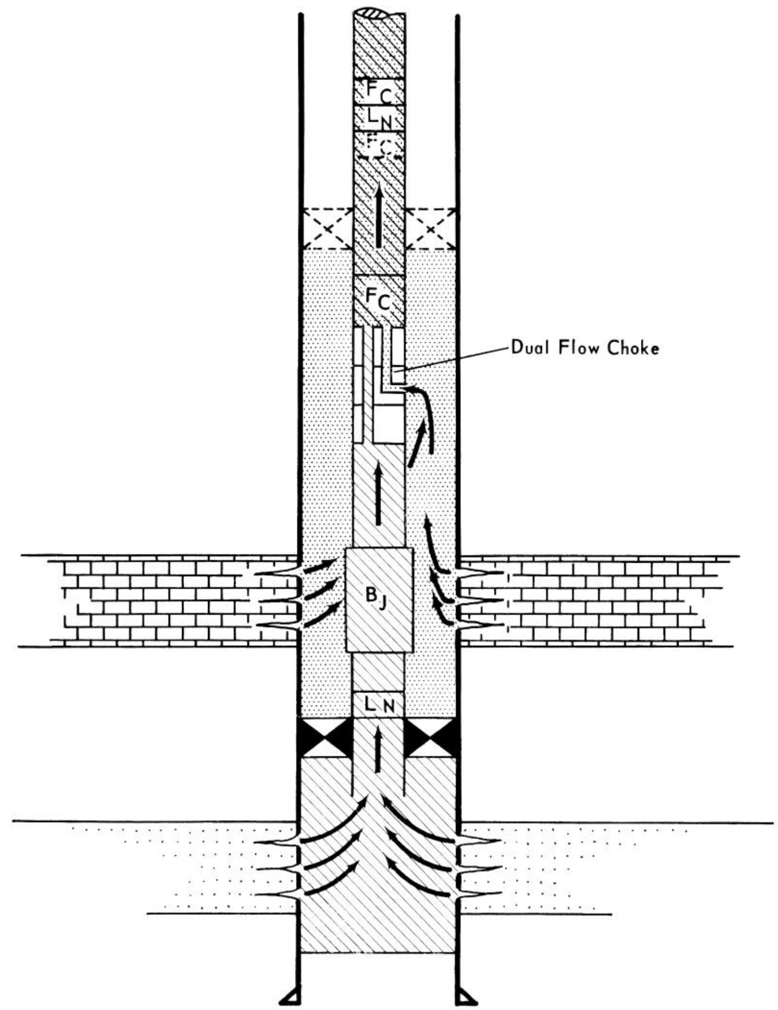
Does permit selectivity as to which zone is produced up the annulus.



TWO ZONES
TWO PACKERS – SINGLE TUBING STRING
TUBING/CASING CROSS-OVER DUAL COMPLETION

Single String, Dual Zone Completion

Downhole choke regulates flow from uppermost zone



TWO ZONES IN ONE TUBING STRING
– SIMULTANEOUS PRORATED FLOW DUAL COMPLETION

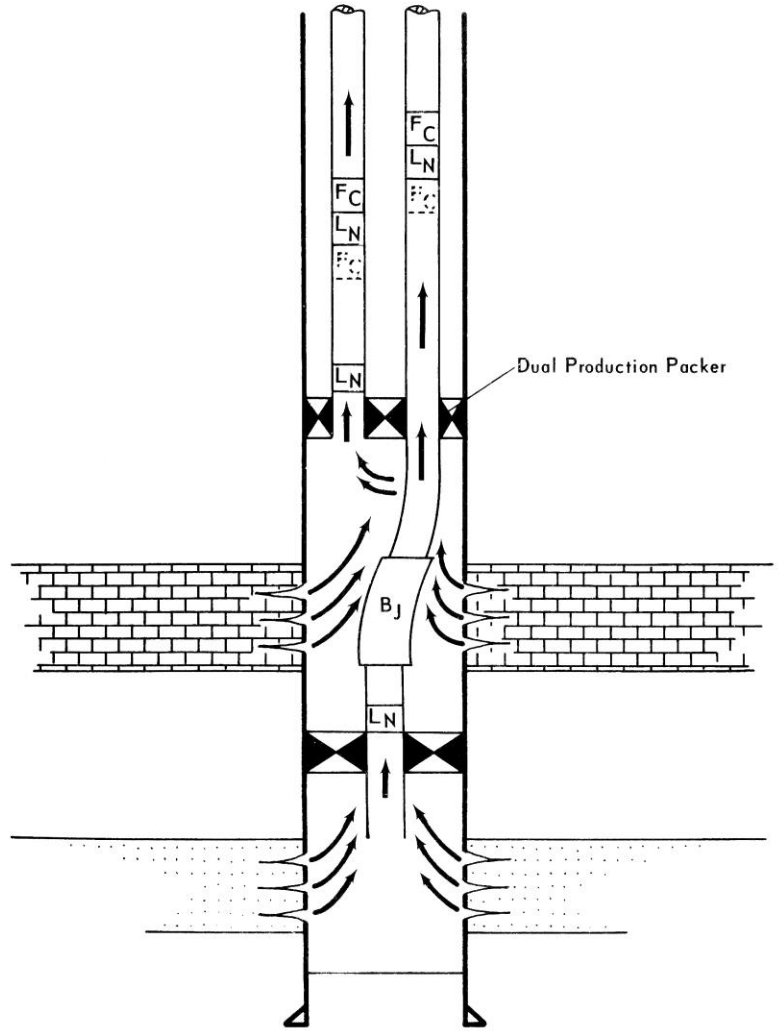
Dual Completion

Dual completion with two tubing strings. Production from lower reservoir is through the ‘long string’ and the upper reservoir flows to the ‘short string’.

Production packers separate zones.

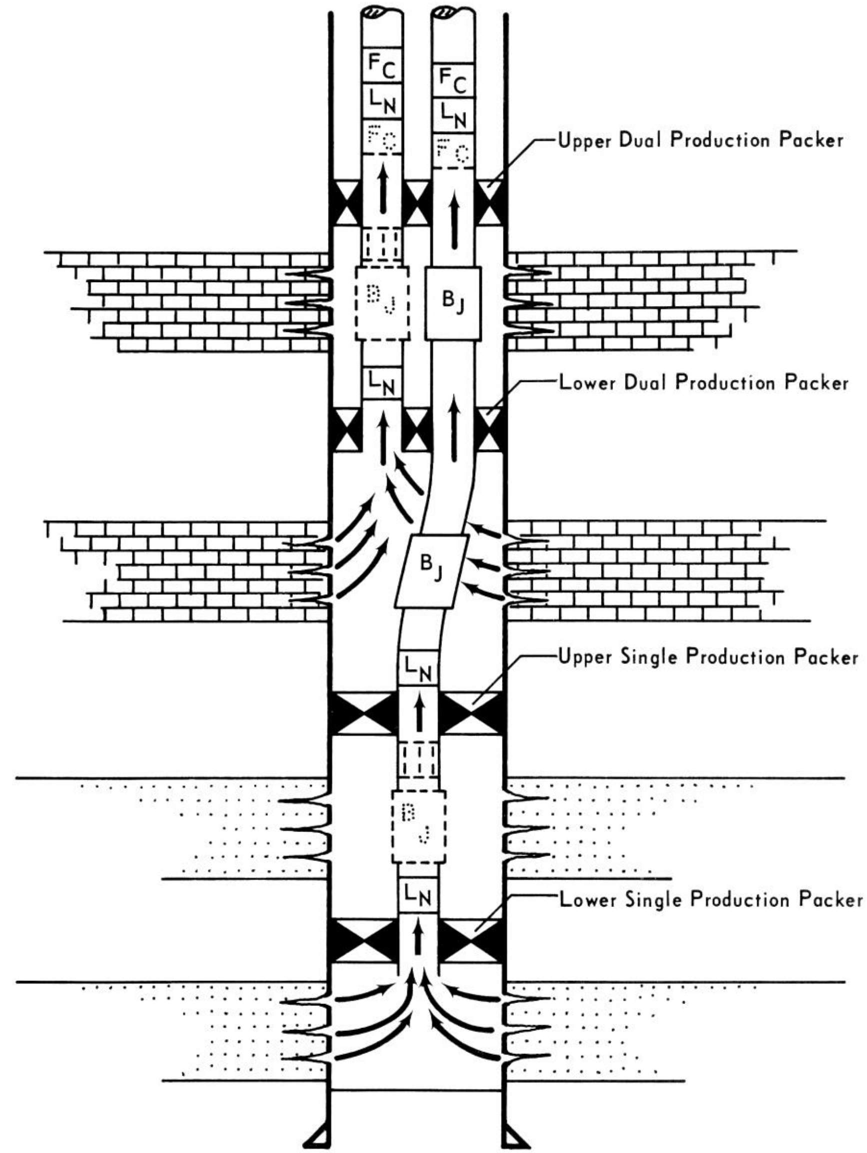
Casing is protected from reservoir fluids. Production from each zone is measured separately.

Workovers of dual expensive and they are more difficulty to install.



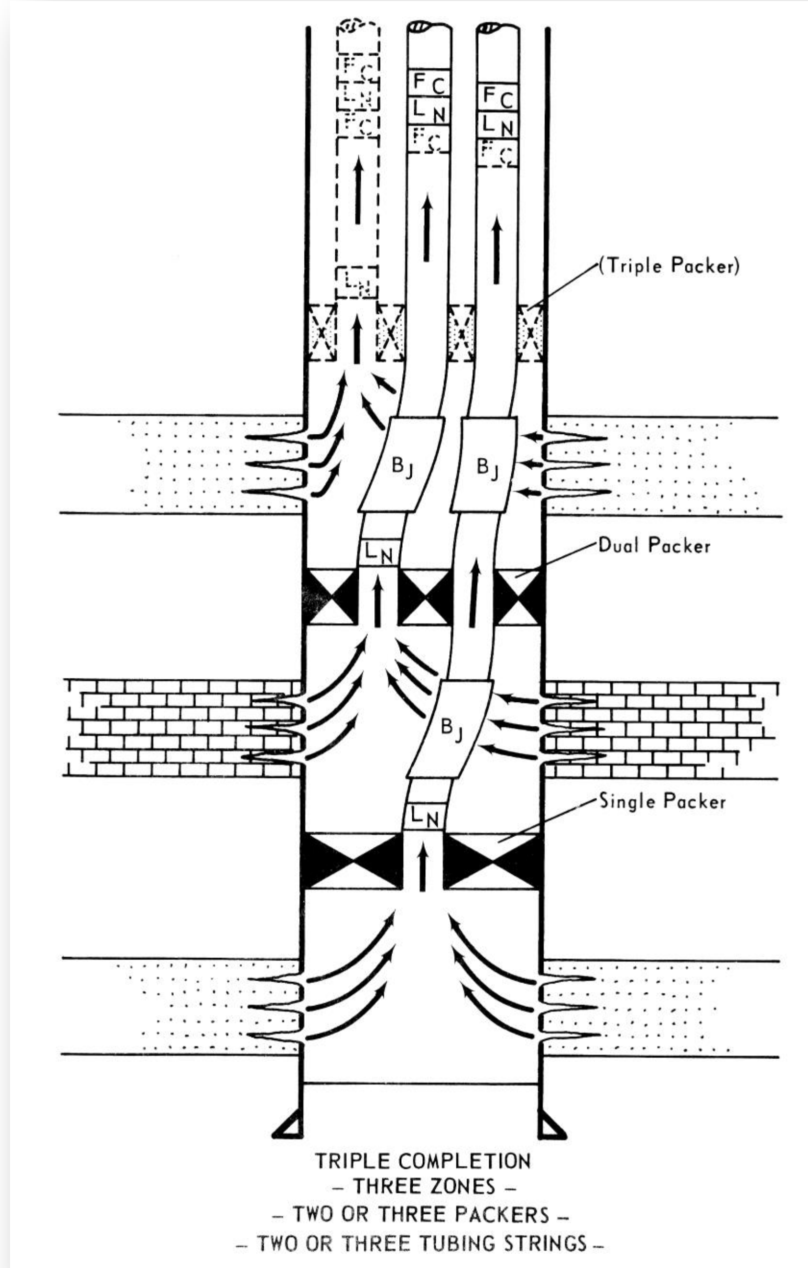
TWO ZONES
TWO PACKERS – TWO TUBING STRINGS
"PARALLEL" DUAL COMPLETION

Dual Completion Multiple Zones

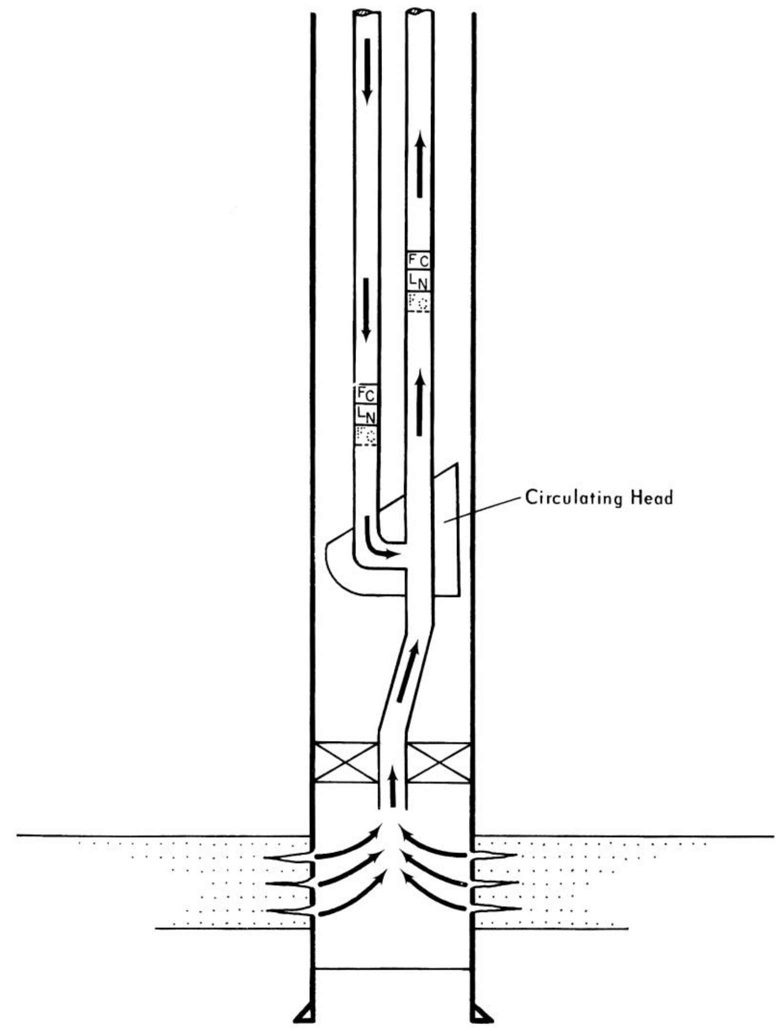


DUAL WELL WITH TWO ALTERNATE COMPLETIONS

Triple Completion



Extra String for Chemical Injection

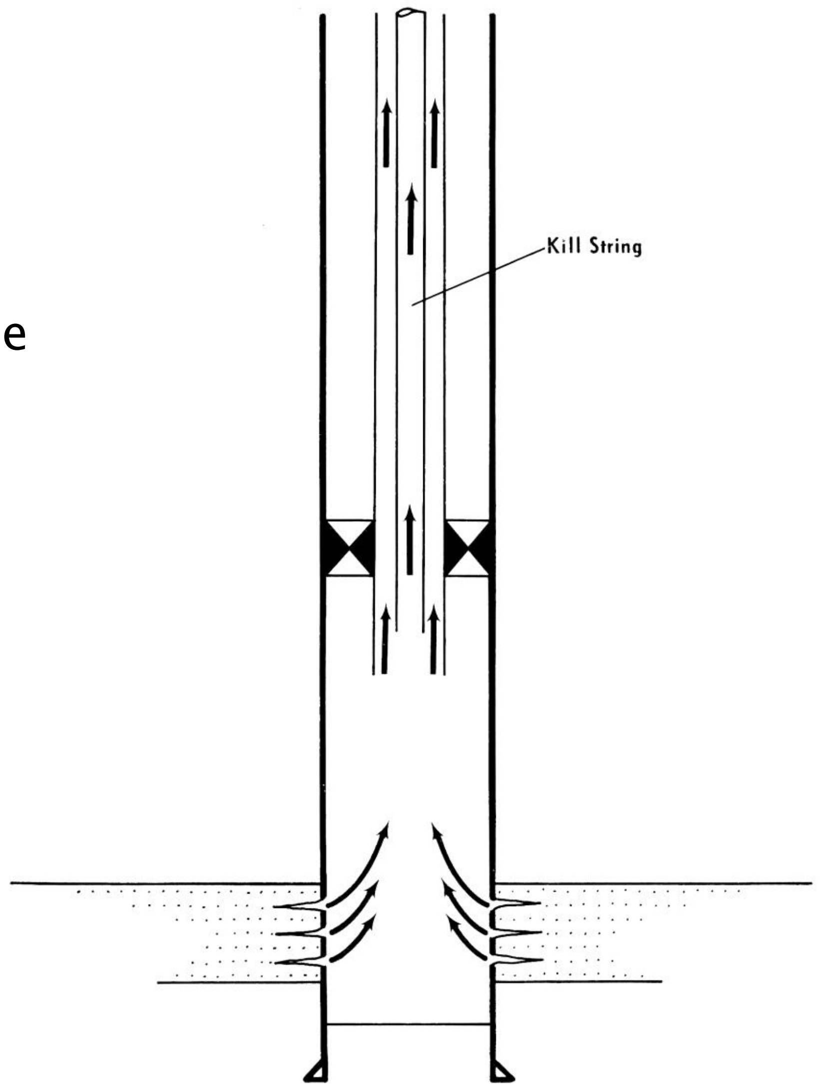


SINGLE COMPLETION WITH EXTRA TUBING STRING FOR CHEMICAL INJECTION

Velocity or Kill String

A small, concentric 'kill string' is used to circulate kill fluids to kill the well when required.

This design can also be used in wells to keep them from dying. In this case the inner tube is referred to as a velocity string.



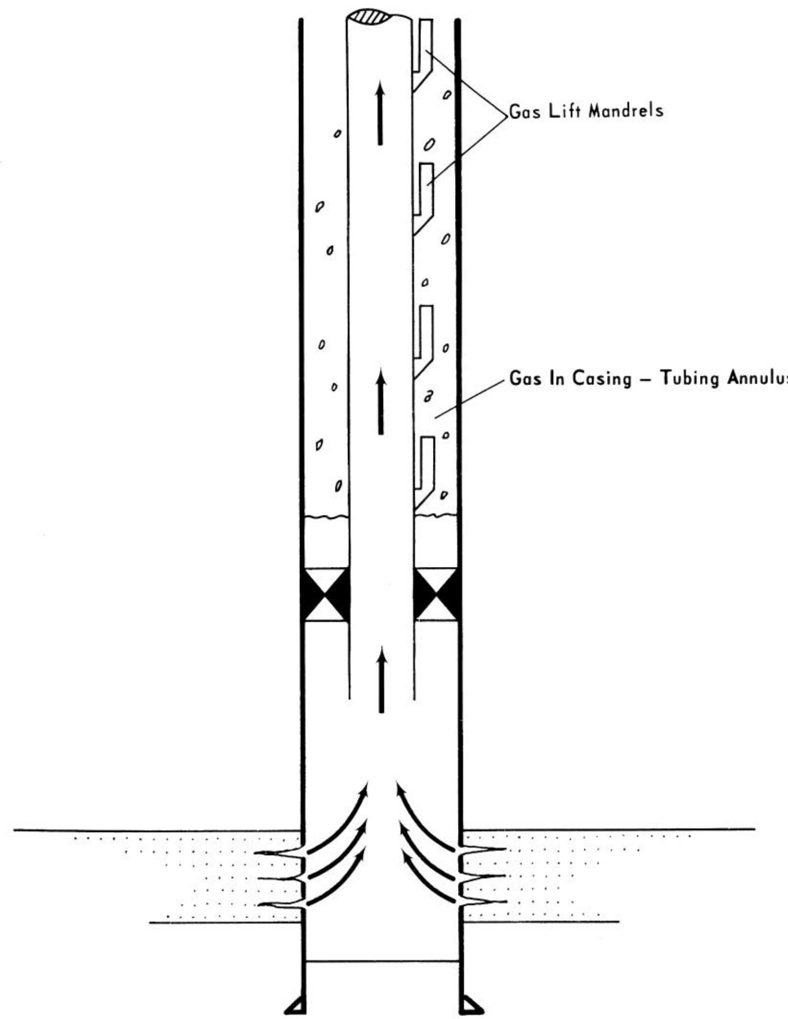
SINGLE COMPLETION WITH CONCENTRIC HIGH PRESSURE KILL STRING

Single String Gas Lift Completion

Side pocket mandrels are added in the tubing string above a packer.

Gas is injected into the tubing-casing annulus and enters the tubing through special valves inserted into the mandrels.

The gas reduces the density of the fluid in the tubing string cause the well to flow.



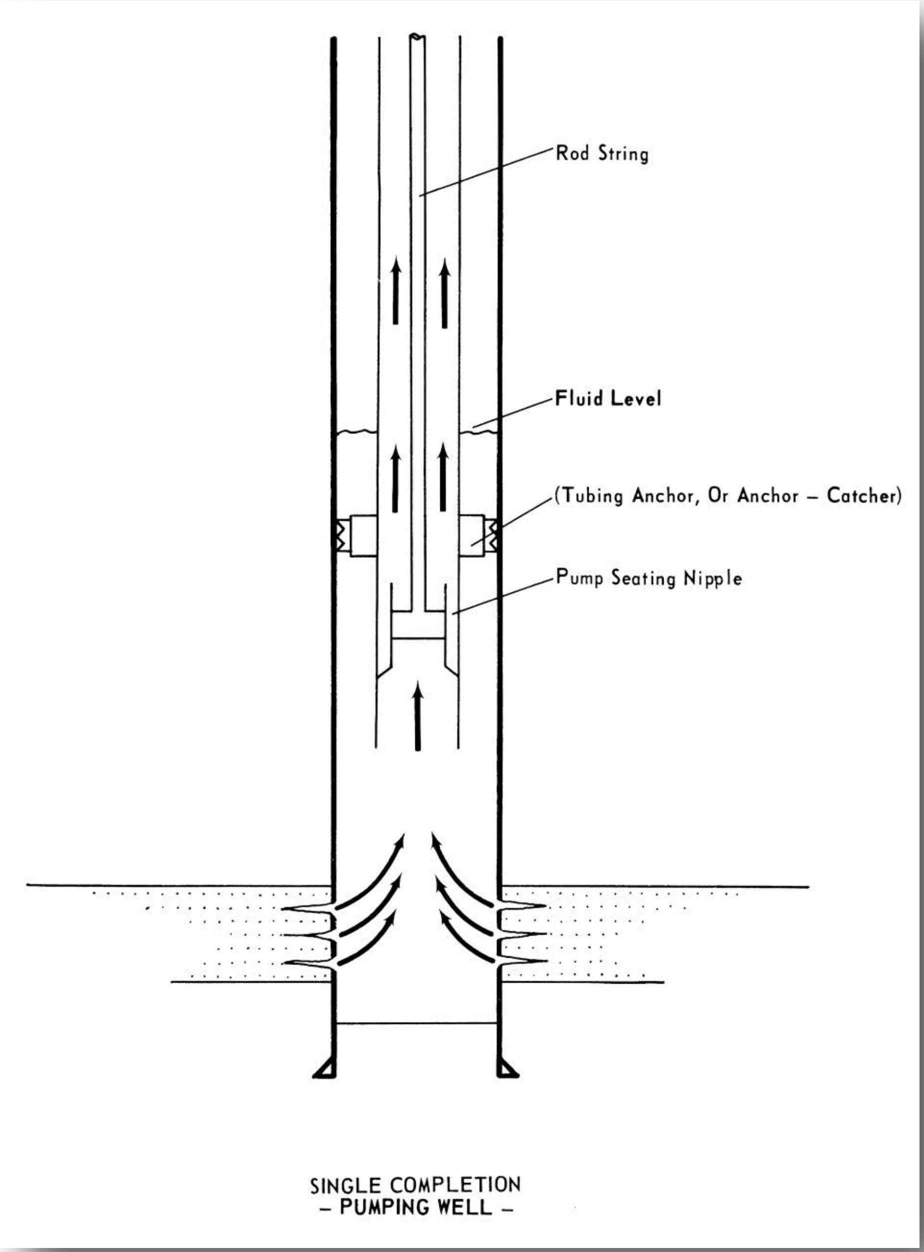
SINGLE COMPLETION
– GAS LIFT

Sucker Rod Pump Completion

Rod string is run inside tubing.

Pump barrel typically part of tubing but can also be an 'insert'.

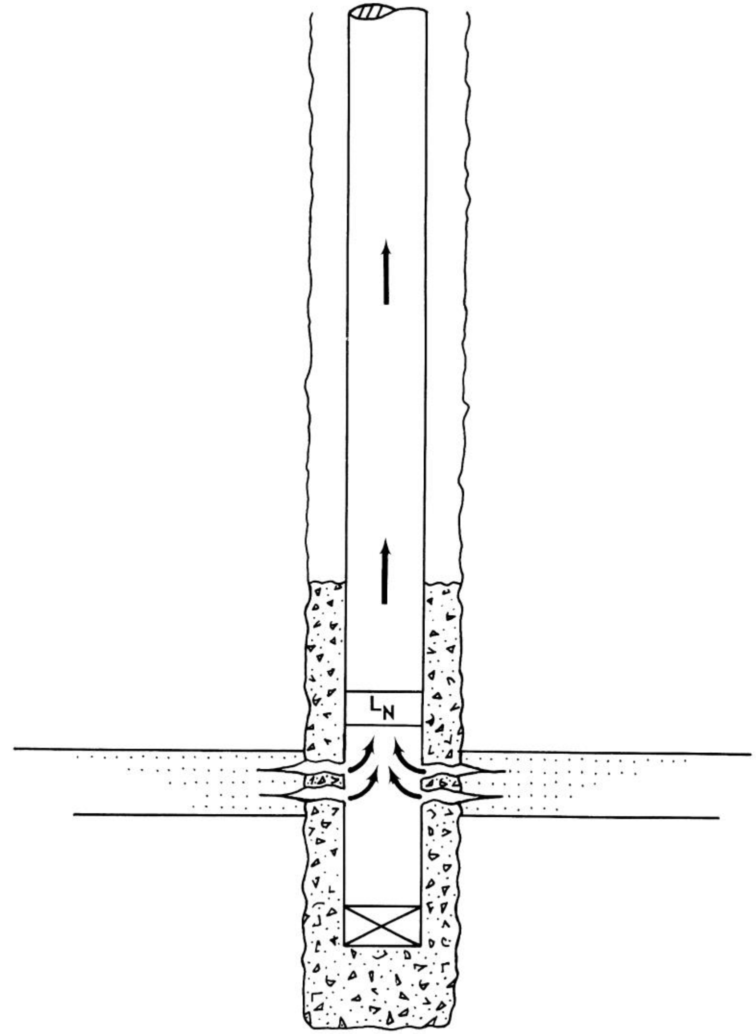
Tubing anchor attaches tubing to casing wall thereby eliminating tubing stretch during the pumping cycle.



Tubingless

Tubing cemented and serves as both casing and tubing.

Poor protection of the annulus if leak develops in pipe above level of bottom cement.



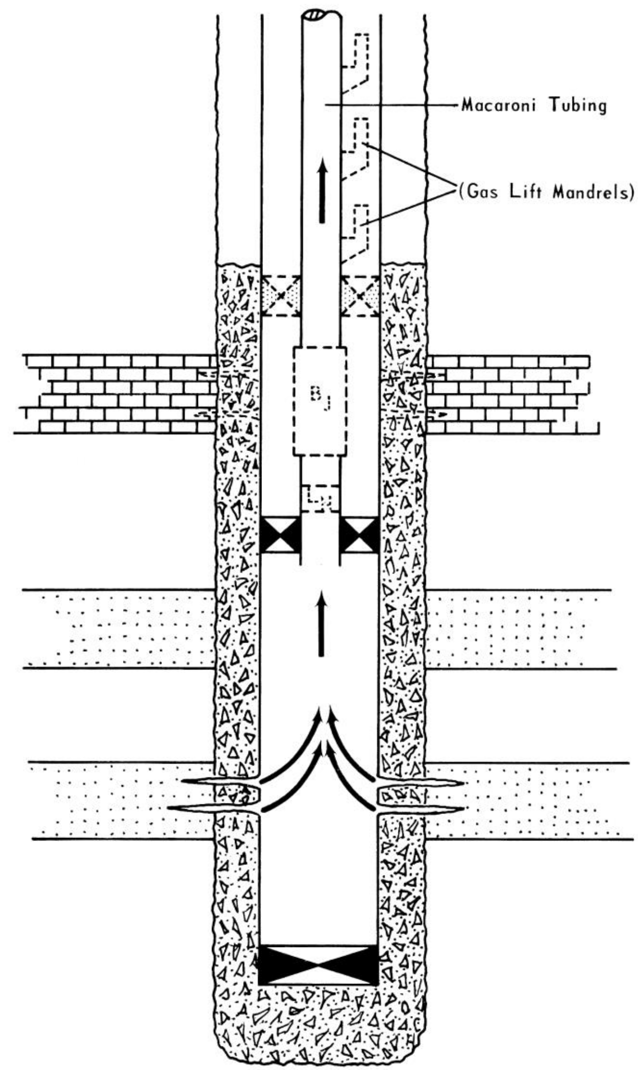
SINGLE TUBINGLESS COMPLETION
– FLOWING WELL –

Tubingless Completion

Reduced diameter ‘macaroni tubing’ used inside tubing string which is cemented in the hole.

Reduced diameter completions represent an attempt by the industry to lower completion investment costs.

Often, drilling costs may be higher initially so it may take multiple completions before cost savings can be realized.

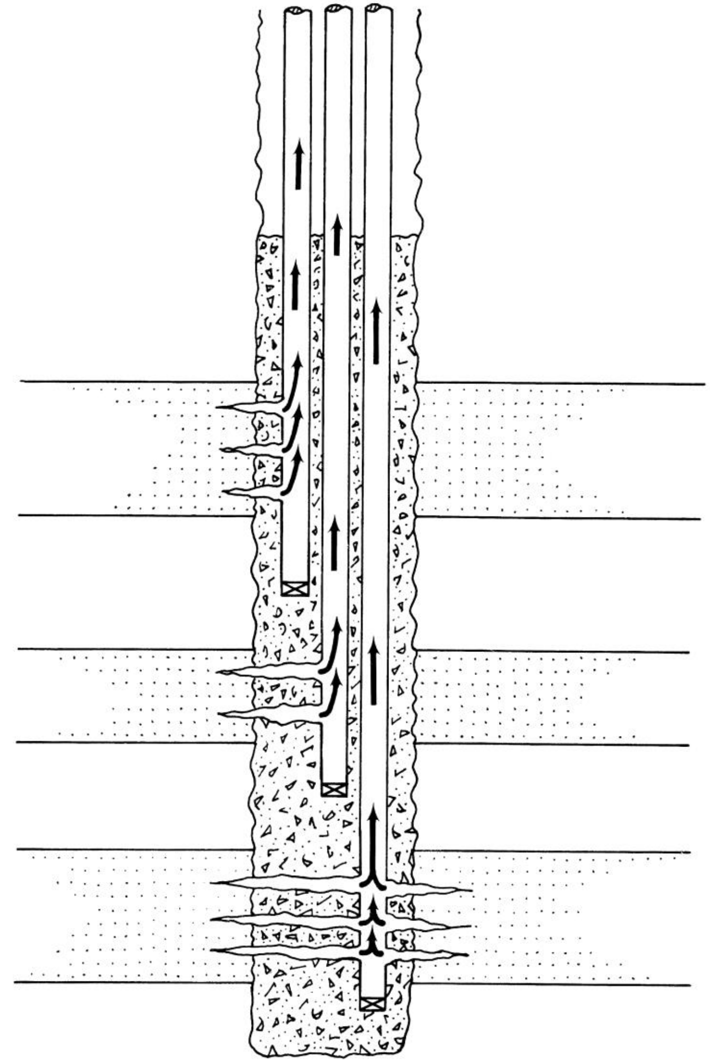


VARIOUS DESIGN POSSIBILITIES
FOR TUBINGLESS COMPLETIONS

Tubingless Completion

Same idea only worse.
Triple completion with three tubes.

This requires careful orientation of the perforation jobs (all must be 0 phased)

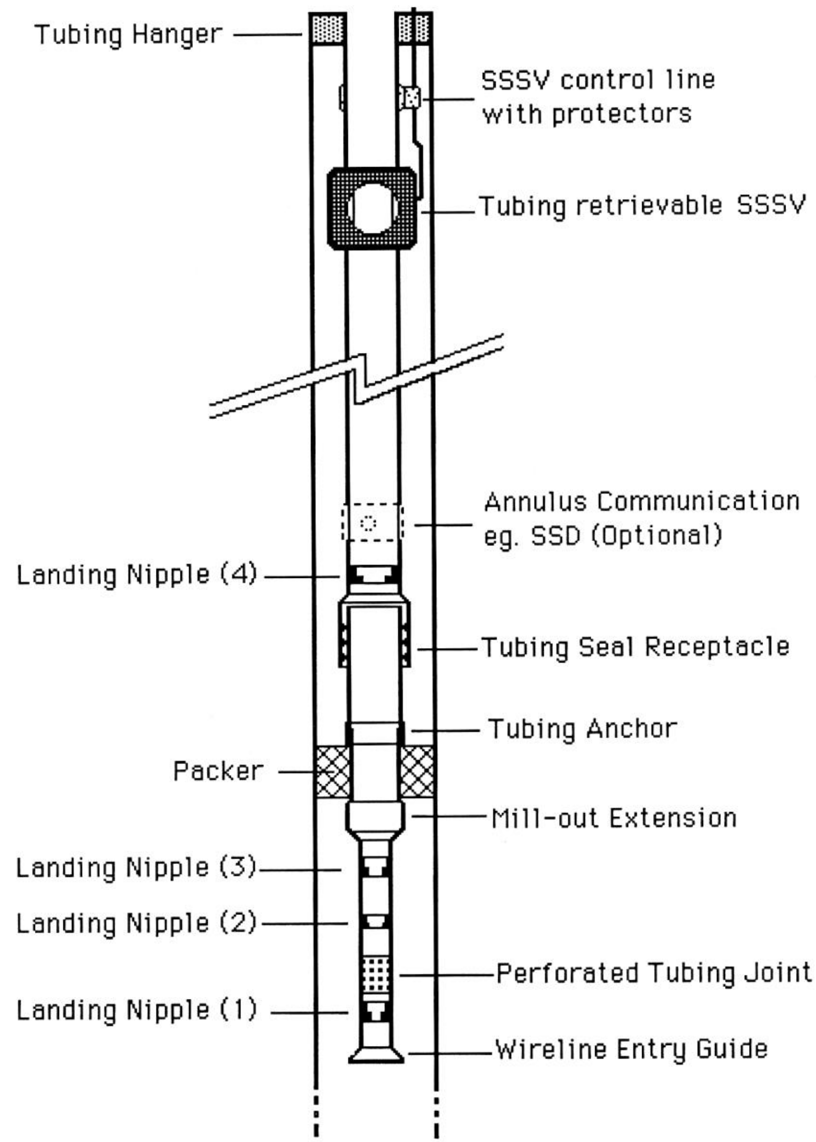


TRIPLE TUBINGLESS COMPLETION

Single String

Single string completion with the ability to remove the tubing at the point of the tubing seal receptacle.

This design has a permanent packer (you can tell because there is a mill out extension in the design).

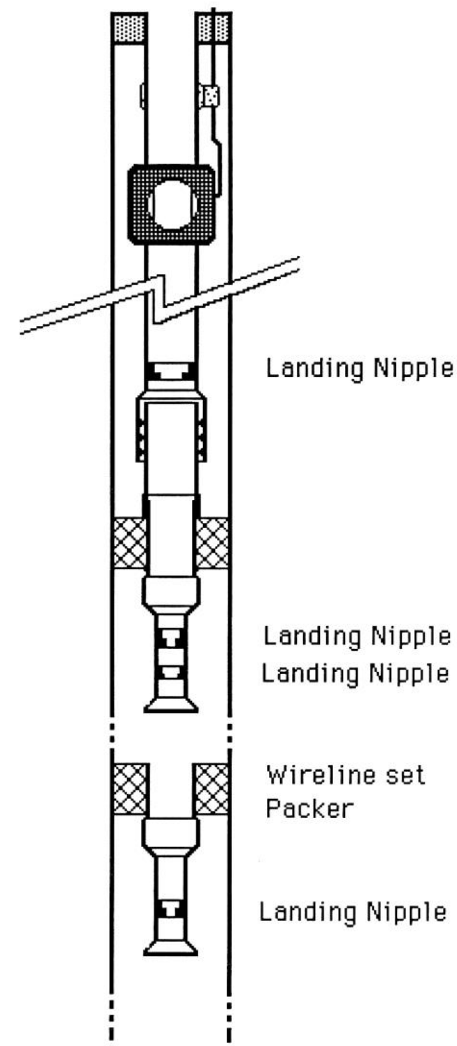


Dual Zones

Permanent packer with tailpipe on bottom. Allows lower zone to be shut off with wireline plug while still producing upper zone.

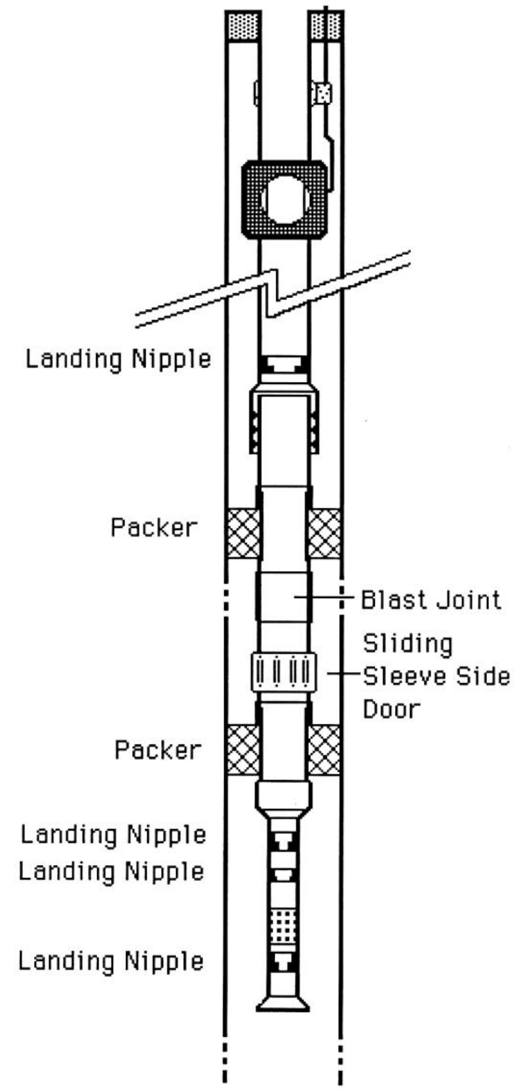
Can remove tubing at the tubing seal receptacle as in previous design, leaving plug in tailpipe of upper zone.

So, this is a selective completion in the sense that you can shut off the lower zone and produce upper only. But you cannot produce the lower only.



Single Completion
Two zones

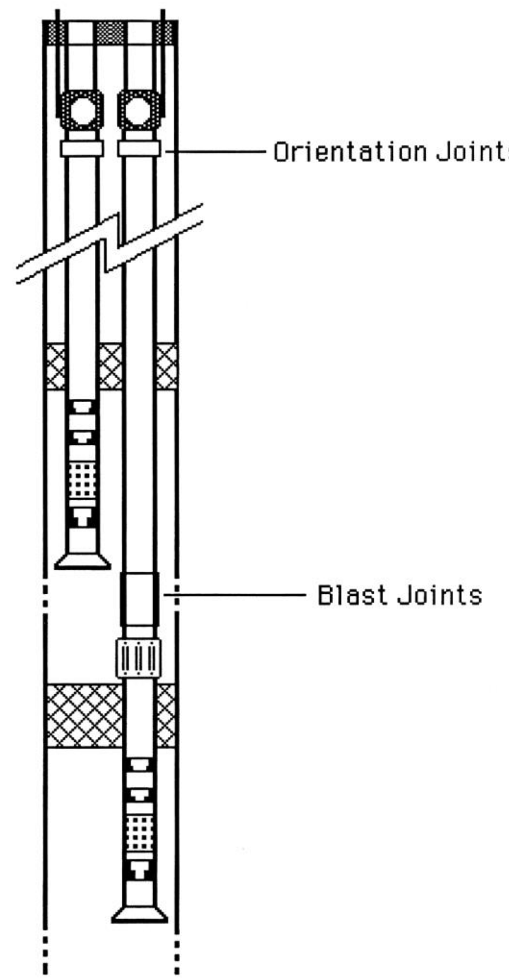
Just another schematic of a single selective completion



Single Completion
2 Zones

Dual Completion, 2 zones

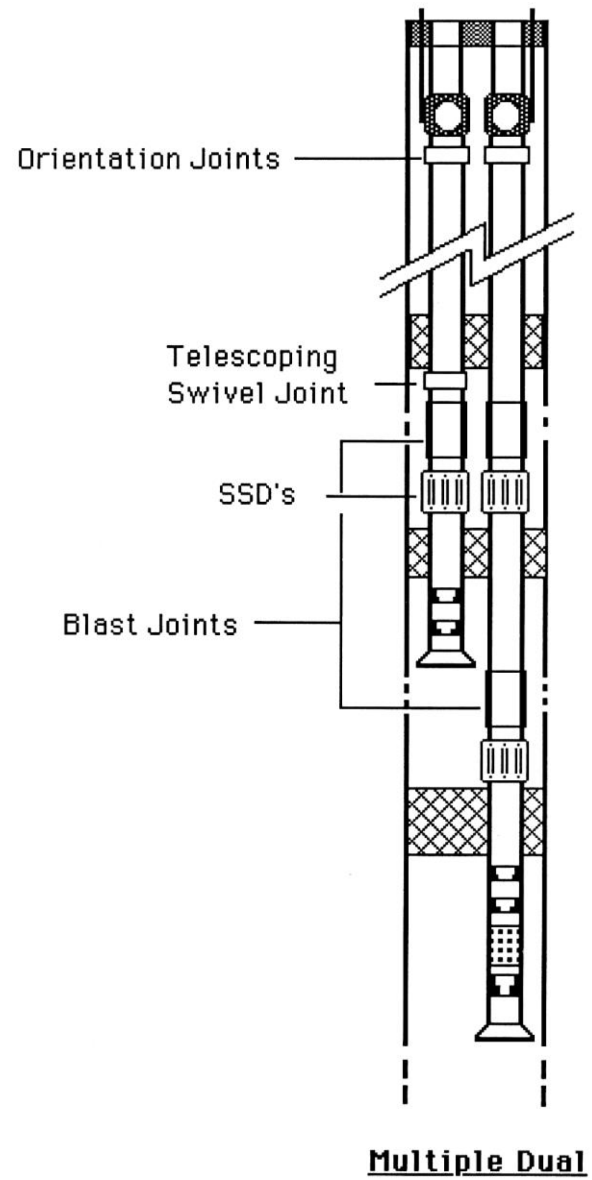
As before, two tubing strings. Long string generally uses a permanent packer with a tailpipe, then a dual bore retrievable packer is used up hole. Long string tubing stabs into permanent packer.



Simple Dual

Dual Completion, 3 zones

Same as previous design except now there are more sliding sleeves

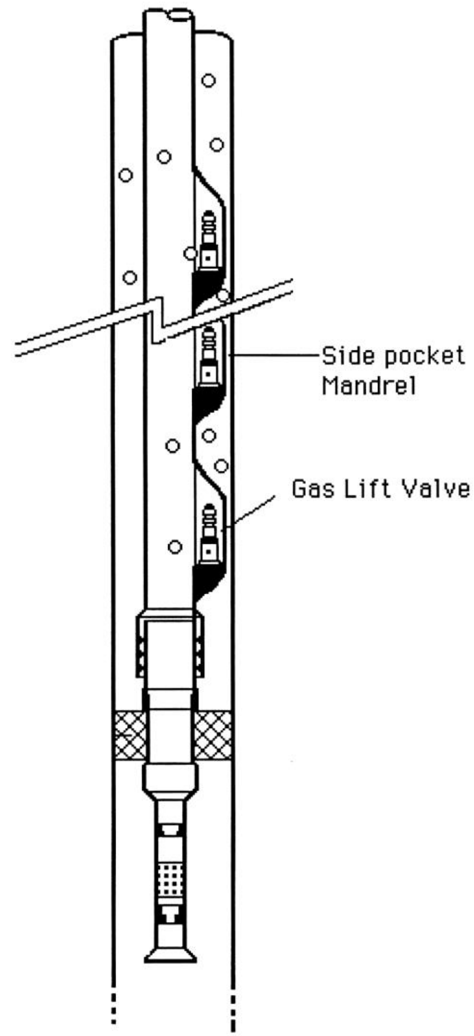


Gas Lift Completion

Always requires a packer

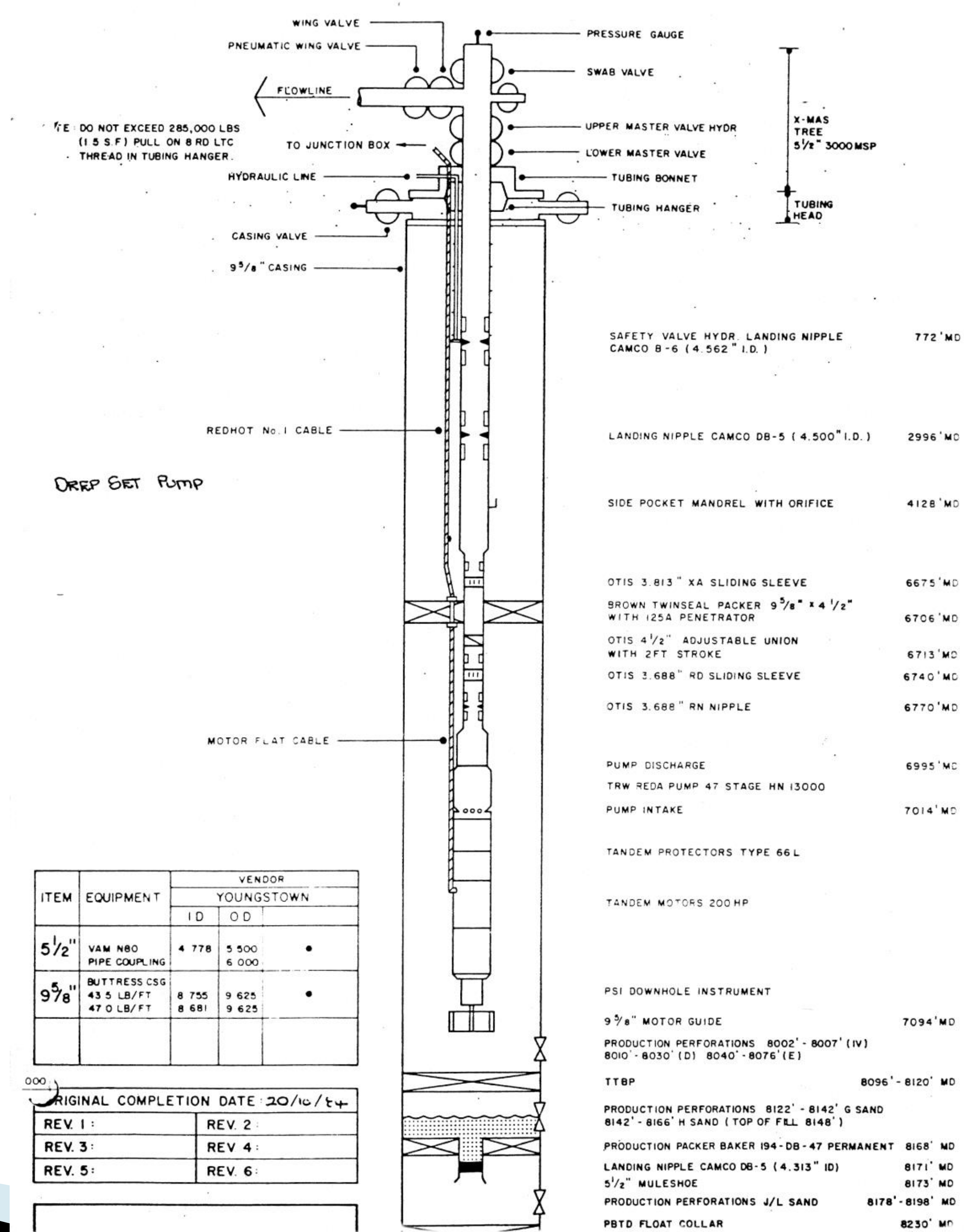
Gas lift valves are used in side pocket mandrels

This design utilizes a stab over tubing seal receptacle, permanent packer with tailpipe



Gas Lift Completion

An example electrical submersible pump completion above a bottom zone that has been sealed off by a bridge plug and cement

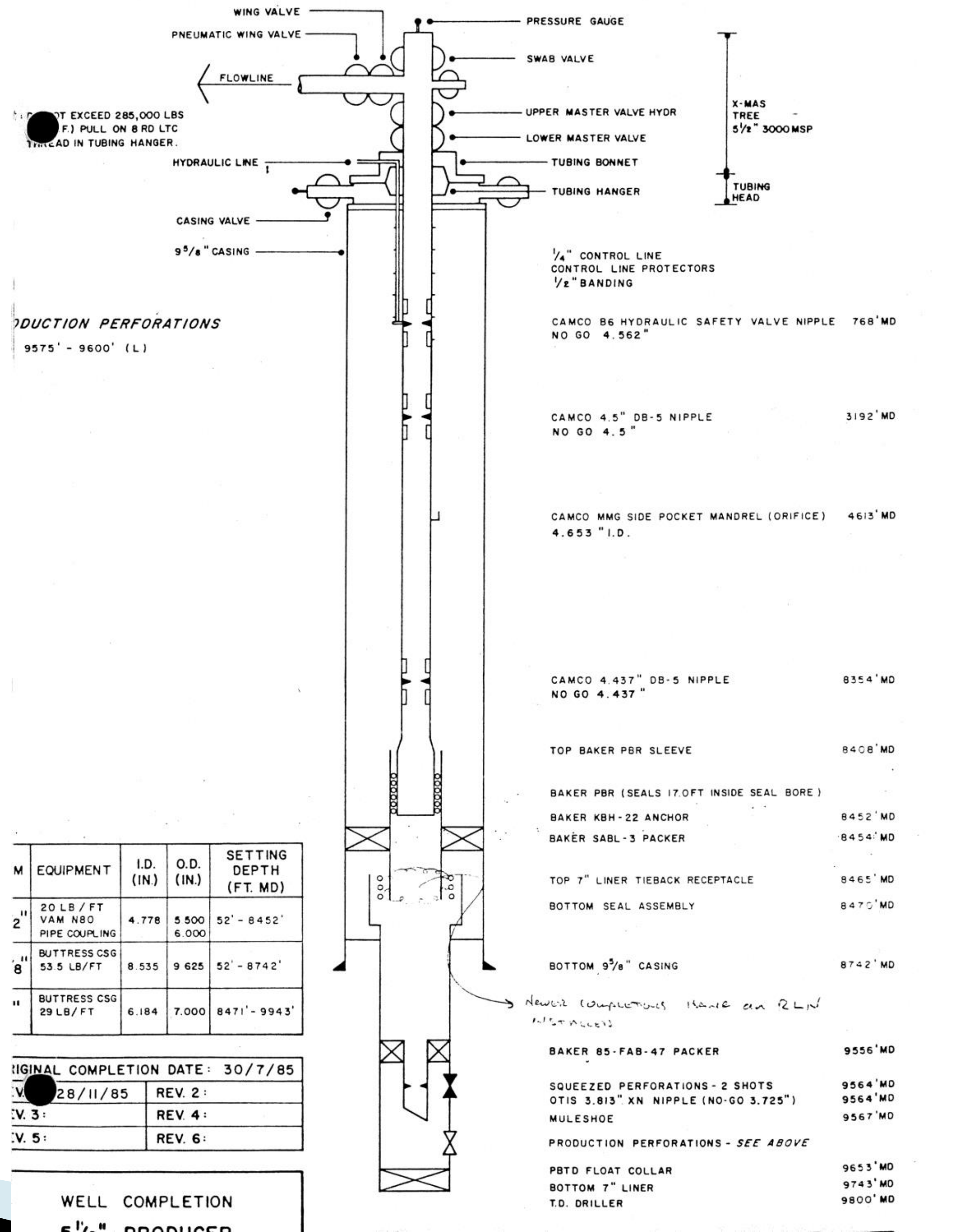


Flowing well completion.

Liner with polished bore receptacle (PBR). Packer with landing nipple in liner to allow lower zone to be shut off with plug.

Packer with stab in seal stack and polished bore set in top of liner.

Tubing with locator seals stabbed into packer.

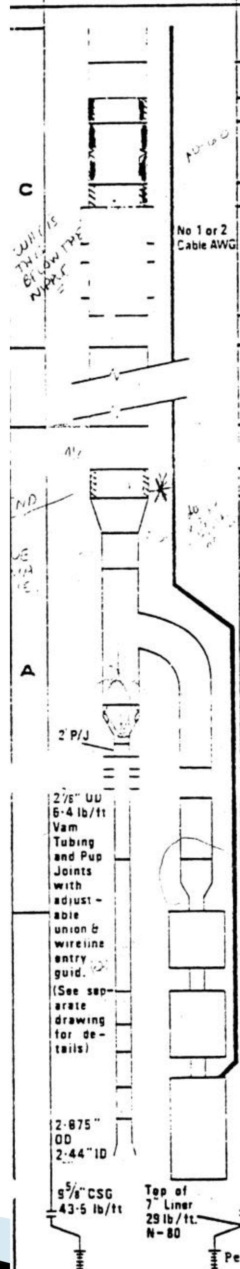


Typical completion running tally showing equipment item, description, threads, ID, OD, length and setting depth.

FIELD WELL COMPLETION EQUIPMENT

11/30a Cont. WITH WIRELINE ADAPTOR

E: OIL PRODUCER CASING SIZE: 9⅝", 43.5lb/ft, N80 LTC TUBING SIZE: 4½", 12.6lb/ft, N80 VAM



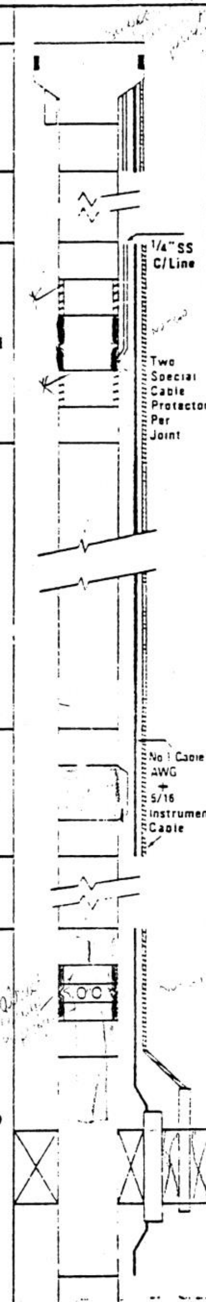
ITEM	THREADS	I.D. (ins.)	O.D. (ins.)	Length (ft.)	Depth (ft.)
					8444.15
Pup joint, 12.6lb/ft, N80	4½" Vam box x pin	3.958	4.862	6.03	8447.16
Baker flow coupling. (6')	4½" Vam box x pin	3.958	5.563	6.07	8453.19
Camco 4½" DB nipple for NO-GO DB lock 12.6lb/ft (assy no. 10255)	4½" Vam box x pin	3.958	4.862	NO-GO 1.10	8459.26
Baker flow coupling (6')	4½" Vam box x pin	3.958	5.563	6.06	8460.36
Camco 4½" Aut-1 adjustable union (24" max extension)	4½" Vam box x pin	4.000	5.563	5.09	8466.42
Pup joint, 12.6lb/ft, N80	4½" Vam box x pin	3. 958	4.862	5.81	8471.51
Prodn tubing/pup joints for space out of motor lead extension cable 12.6lb/ft, N80	4½" Vam box x pin	3.958	4.862	103.44	8477.32
Pup joint, 12.6lb/ft, N80	4½" Vam box x pin	3.958	4.862 ← 4.961?	3.86	8580.76
Baker flow coupling	4½" Vam box x pin	3.958	5.563	4.03	8584.62
X-over	4½" Vam box x 3½" EUE 8RD pin	2.992	4.862	1.36	8588.65
Pup joint 9.3lb/ft, N80	3½" EUE 8RD box x pin	2.992	3.500	4.96	8590.01
Wireline adaptor tool c/w wireline retrievable plug. Permits production logging with pump running. 2.272" ID landing nipple for 1.75" external fishing neck Monarch plug.	3½" EUE 8RD box x 3½" EUE 8RD pin (RHS) 2⅞" Vam pin (LHS)	2.272	8.450	2.35	8594.97
Pup joint 9.3lb/ft, N80	3½" EUE 8RD box x pin	2.992	3.500	1.58	8597.32
Pup joint 9.3lb/ft, N80 (10')	3½" EUE 8RD box x pin	2.992	3.500	3.90 8.07	8598.90
X-over 9.3lb/ft, N80	3½" EUE 8RD box x 2⅞" EUE 8RD pin	2.992 1.995	3.5	1.34	8610.87
Centrilift 513 series KA100, E127 or S175 pump	2⅞" EUE 8RD box		5.13	25.91	8636.78
Centrilift seal section, 513 series type GSBP			5.13	6.31	8643.09
Centrilift 544 series GMP motor. 225HP for KA100/E127 350HP for S175			5.--	29.60	8672.69 (MOTOR BOTTO. DIFFERS BY ±5' FROM EXAMPLE BECAUSE WE ARE MISSING A 2ND 5' PUP BELOW THE PACKER)

Bottom part of previous tally.

Depths won't be available until completion is run in the well.

WELL 11/30a

TYPE: OIL PRODUCER CASING SIZE: 9⅝", 43.5 lb/ft, N80, LTC TUBING SIZE: 4½", 12.6 lb/ft, N80



ASSEMBLY	ITEM	THREADS	I.D. (ins.)	O.D. (ins.)	Length (ft.)	Depth (ft.)
I	McEvoy SLA-3 hanger. 10" bowl with 4½" Vam female top and bottom. Female top with 4" nom CIW type H BPV threads to accept 2-way check valve (Pt no. 1107603). C/W electrical penetrator and ¼" C/L	4½" Vam box x 4½" Vam box	3.958		0.40	59.00
	Single joint of tubing 12.6 lb/ft, N80	4½" Vam box x pin	3.958	4.862	27.19	59.40
	Prodn tubing string. 12.6 lb/ft, N80	4½" Vam box x pin	3.958	4.862	936.74	86.59
H	Pup joint 12.6lb/ft, N80	4½" Vam box x pin	3.958	4.862	6.12	1023.33
	Baker flow coupling (4')	4½" Vam box x pin	3.958	5.563	4.05	1029.45
	Camco 4½" BA -6 SCSSSV landing nipple with 4" B-6 pack-off. 12.6 lb/ft (assy No. 10254)	4½" Vam box x pin	3.813 (3.75)	5.598	2.26 NO-GO	1033.5
	Baker flow coupling (6')	4½" Vam box x pin	3.958	5.563	6.07	1035.76
	Pup joint 12.6 lb/ft, N80	4½" Vam box x pin	3.958	4.862	6.09	1041.83
	Prodn tubing string 12.6 lb/ft, N80	4½" Vam box x pin	3.958	4.862	7261.09	1047.92
	Pup joint 12.6lb/ft, N80	4½" Vam box x pin	3.958	4.862	5.33	8309.01
E	Camco 4½" MMG side pocket mandrel with S14R shear out valve and RKP latch	4½" Vam box x box	3.89	7.031	8.86	8314.34
	Pup joint 12.6lb/ft, N80	4½" Vam pin x pin	3.958	4.862	5.19	8323.2
	Prodn tubing (1 stand -2or3 joints 12.6lb/ft, N80	4½" Vam box x pin	3.958	4.862	88.50	8328.39
	Pup joint 12.6lb/ft, N80	4½" Vam box x pin	3.958	4.862	6.05	8416.89
	Camco 4½" type DB-1 sliding sleeve with 3.687" DB landing nipple for DB Lock No.10260	4½" Vam box x pin	3.687	5.500	5.55 NO-GO	8422.94
	Pup joint 12.6lb/ft, N80 (10')	4½" Vam box x pin	3.958	4.862	11.14	8428.49
D	~~Otis~~ or Brown dual hydraulic set straight pull release packer. c/w electrical penetrator for pump and penetrator for Flopetrol DPTT gauge (gauge mounted above packer). Brown pkr : BIW penetrator. Otis pkr : Slingsby penetrator (see electrical diagram for details)	4½" Vam box x pin. Brown pkr : 125 A penetrator. Otis pkr : 115 A penetrator	4.000	8.430 MID PACKER	4.52	8439.63
	Pup joint 12.6lb/ft, N80	4½" Vam box x pin	3.958	4.862	5.01	8444.15

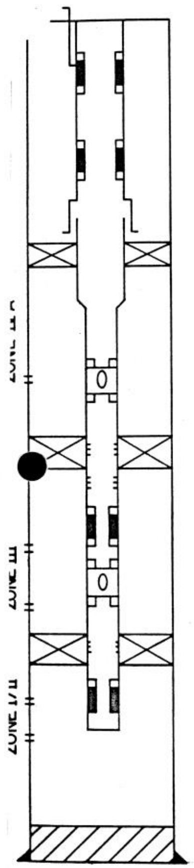
From the Ninian Field North Sea.

Another example of how the completion diagram may be made.

WELL C 41 COMPLETION

SLOT 24

Lower Reservoir Producer
North Fault



ITEM	MIN. I.D.	DEPTH	NOTES
FLOW COUPLING	4·778"	698'	
OTIS TRBV	4·562"	704'	No. 208 SERIES 10
FLOW COUPLING	4·778"	712'	
FLOW COUPLING	4·394"	11472'	
OTIS XN L/N	4·157" NO-GO	11476'	Pack Bore 4·313"
FLOW COUPLING	4·394"	11477'	
ELTSR	4·857"	11547'	
BAKER SAB	4·760"	11592'	
X/O TO 4½"	3·976"	11602'	
FLOW COUPLING	3·895"	11740'	
SLIDING SLEEVE	3·813"	11746'	OTIS XD
FLOW COUPLING	3·895"	11750'	
BAKER PACKER	–	11774'	FB-1 (G36 LOCATR. with 6' seals
FLOW COUPLING	3·895"	11810'	
OTIS RN L/N	3·456" NO-GO	11816'	Pack Bore 3·688"
FLOW COUPLING	3·895"	11818'	
FLOW COUPLING	3·895"	11840'	
SLIDING SLEEVE	3·313"	11845'	OTIS XD
FLOW COUPLING	3·895"	11849'	
BAKER PACKER	–	11874'	FB-1 (E36 LOCTR. with 14' seals)
FLOW COUPLING	3·895"	11882'	
OTIS RN L/N	2·907" NO-GO	11888'	Pack Bore 3·125"
MULE SHOE	3·993"	11889'	

REF: FDC / CNL FILE 26

PERFORATIONS	ZONE
11642' - 653'	IV A
11663' - 669'	IV A
11681' - 698'	IV A
11737' - 761'	IV A
11783' - 865'	III
11876' - 895'	II
11940' - 970'	I

REPERFORATED 8/84 W 4" CASING GUNS

PBTD 12045	6·184"	12045'	W.D. (SCHL.)

TREE No. ME182

KBE 620' (ML) 308 JTS; 180' (MSL) 4 JTS; 63' (THF)

DEVIATION 46° (MAX) AT 5191'; 30° AT TD

CASING 9⅝" GRADE N 80 WEIGHT 47/435 PPF SET AT 12085'

TUBING 5½" GRADE N 80 WEIGHT 17 PPF

TUBING 4½" GRADE L 80 WEIGHT 12·6 PPF

COMPLETED 23·3·82

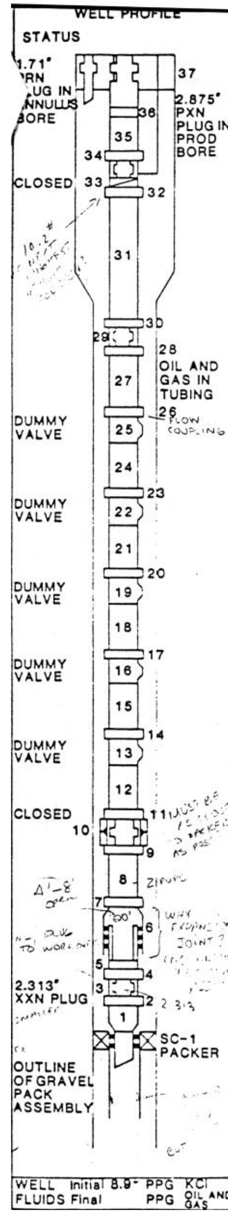
P.O.P. 24·3·82

STATUS AS OF WO 'E' 6·9·85

Example completion schematic and equipment detail from the Balmoral Field in the North Sea.

This is a gravel pack completion (for sand control).

This was also an early subsea completion (meaning the tree is on the seafloor)



WELL 16/21a-B4 RIG PACESETTER ONE

FIELD

COUNTRY U.K. NORTH SEA

Completion Witnessed By S. ROBERTSON

DATE 16th APRIL 1986

☐ New Completion ■ Re-Entry No.1

☐ Injector ■ Producer

SIZE	9-5/8	7-5/8	3-1/2	
WEIGHT	47	33.7	9.3	
GRADE	N80	N80	L80	
THREAD	BTC	BTC	HCS	
DEPTH	1010.98	11499	10914	

ITEM No.	EQUIPMENT	TESTED	DRIFTED	MIN I.D. (IN)	MAX O.D. (IN)	LENGTH (FT)	DEPTH (TOP OF)
37	VETCO PRODUCTION TBG. HCR. 9 (SER. NO. AB-168830-3)						MD(RKB)
	-ABOVE LANDING SHOULDER					2.38	550.33
	-BELOW LANDING SHOULDER					0.79	552.71
36	ONE JT. 3-1/2", 9.3lb/ft HCS TBG			2.92	3.5	30.23	553.50
	with VAM PIN x HCS PIN						
35	8 JTS plus 3 PUP JTS 3-1/2" 9.3 lb/ft			2.92	3.5	263.80	583.73
	HCS TBG						
34	FLOW COUPLING			2.93	3.85	6.10	847.53
33	CAMCO 3-1/2" TRDP-2AH-SSA-NS with			2.75	5.70	9.45	853.63
	2.75" "C" TYPE NO-GO LOCK (SERIAL NO BBS 118)						
32	FLOW COUPLING			2.93	3.85	6.08	863.08
31	20 JTS plus 2 PUP JTS 3-1/2", 9.3lb/ft HCS TBG			2.92	3.5	634.92	869.16
30	FLOW COUPLING			2.93	3.85	6.10	1504.08
29	OTIS 2.75" "X" LANDING NIPPLE			2.75	3.85	0.95	1510.18
28	FLOW COUPLING			2.93	3.85	6.08	1511.13
27	60 JTS plus 2 PUP JTS 3-1/2", 9.3lb/ft HCS TBG			2.92	3.5	1881.55	1517.21
26	FLOW COUPLING			2.93	3.85	5.99	3398.76
25	CAMCO MMG SPM with DUMMY VALVE			2.90	5.97	8.49	3404.75
	INSTALLED (SERIAL NO. BBM 223)						
24	54 JTS plus 2 PUP JTS 3-1/2", 9.3lb/ft HCS TBG			2.92	3.5	1695.00	3413.24
23	FLOW COUPLING			2.93	3.85	6.09	5108.24
22	CAMCO MMG SPM with DUMMY VALVE			2.90	5.97	8.51	5114.33
	INSTALLED (SERIAL NO. BMM 220)						
21	43 JTS plus 2 PUP JTS 3-1/2", 9.3lb/ft HCS TBG			2.92	3.5	1351.67	5122.84
20	FLOW COUPLING			2.93	3.85	6.09	6474.51
19	CAMCO MMG SPM with DUMMY VALVE			2.90	5.97	8.45	6480.60
	INSTALLED (SERIAL NO. BBM 226)						
18	26 JTS plus 2 PUP JTS 3-1/2", 9.3lb/ft HCS TBG			2.92	3.5	821.48	6489.05
17	FLOW COUPLING			2.93	3.85	6.10	7310.53
16	CAMCO MMG SPM with DUMMY VALVE			2.90	5.97	8.50	7316.63
	INSTALLED (SERIAL NO. BBM 222)						
15	32 JTS plus 2 PUP JTS 3-1/2", 9.3lb/ft HCS TBG			2.92	3.5	1009.43	7325.13
14	FLOW COUPLING			2.93	3.85	6.10	8334.56
13	CAMCO MMG SPM with DUMMY VALVE			2.90	5.97	8.49	8340.66
	INSTALLED (SERIAL NO. BBM 225)						
12	79 JTS plus 2 PUP JTS 3-1/2", 9.3lb/ft HCS TBG			2.92	3.5	2474.81	8349.15
11	FLOW COUPLING			2.93	3.85	6.08	10823.96
10	OTIS R.D. SLIDING SIDE DOOR (2.562")			2.56	4.31	3.37	10830.04
9	FLOW COUPLING			2.93	3.85	6.08	10833.41
8	2 PUP JTS 3-1/2",9.3lb/ft HCS TBG			2.92	3.5	12.01	10839.49
7	FLOW COUPLING			2.93	3.85	6.10	10851.50
6	CAMCO OEJ EXPANSION JT. (SERIAL NO.			2.93	5.62	34.85	10857.60
	BBE 116) LENGTH OF OEJ IN FULLY CLOSED POSITION - 27.76"						
5	2 PUP JTS 3-1/2", 9.3lb/ft HCS TBG			2.92	3.5	8.47	10892.45
	WELL HUD -11387 (DATE 15.4.86)				TOTAL-		

PERFORATED INTERVALS- 11080'-11102' MD(RKB) 7036.3'-7052.2' TVD (RKB)
11110'-11130' MD(RKB)(7058'-7072.6 TVD(RKB)

SAND UNITS PERFORATED- 5,4/3D,3C

SHOT DENSITY/GUN TYPE-12 SPF/SCHLUMBERGER TCP GUNS with 5" 22GM ULTRAPACK II CHARGES

RKB TO MSL- 83'

RKB TO TOP H-4 W/HEAD PROFILE- 550.00

Crazy design a friend of mine made in the Java Sea (Indonesia).

Their challenge is many zones…

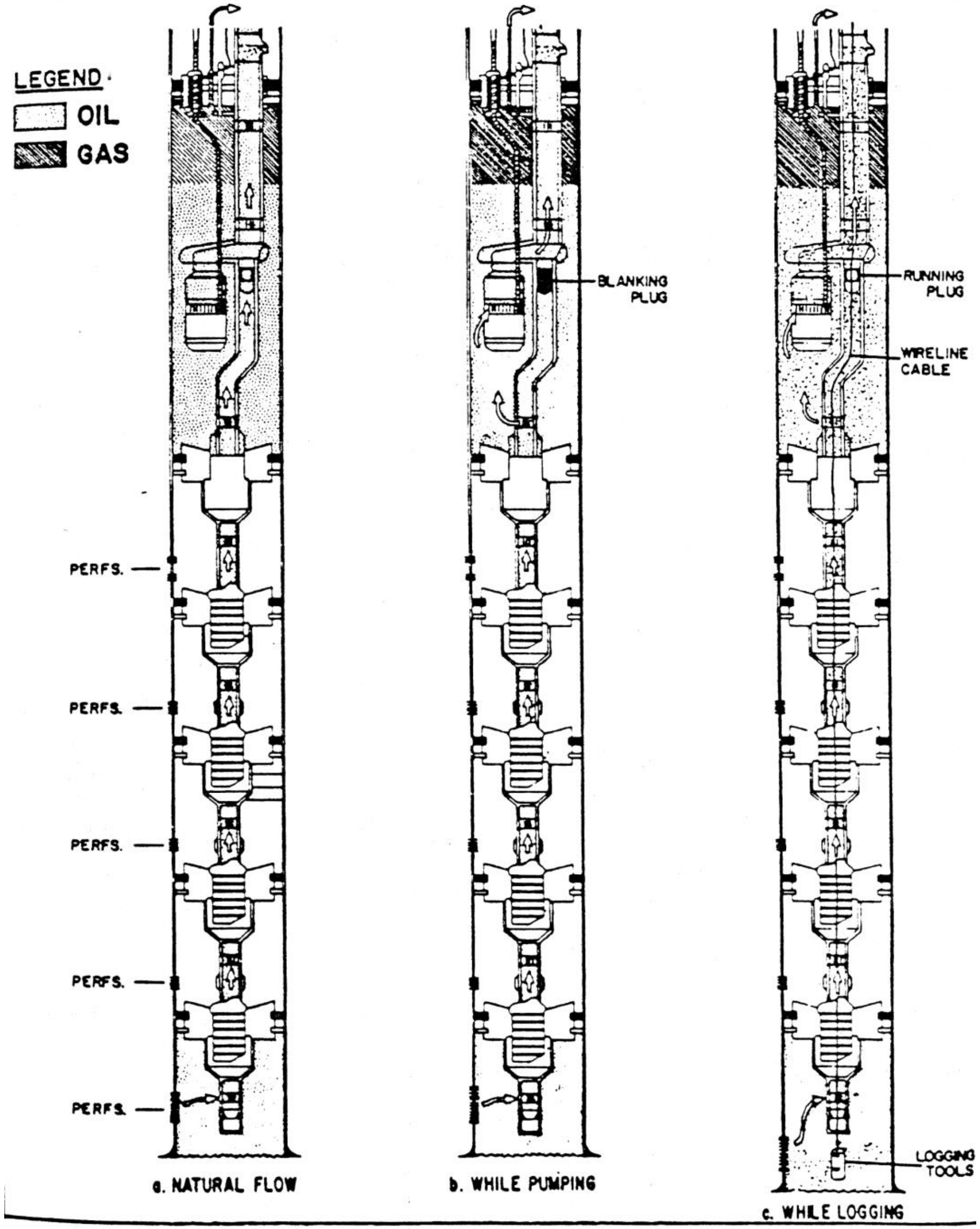


Figure 1-7 Northwest Java Sea Well Completion

Types of Completions Summary

- Completions are categorized in many ways but what you use is related to the functional requirements for the well
  - Land, offshore platform, TLP, subsea – all imply different requirements due to location
  - Flowing, Gas lift, rod pump, ESP, Plunger Lift – if the well cannot flow one of the artificial lift methods must be used
  - Gravel pack, screens, high rate water pack, frac pack – types of completions where sand control is necessary
  - Geometry – vertical, deviated, extended reach, horizontal
  - Number of zones – single, dual
  - Uniform tubular size – monobore
  - Order of producing multiple zones – comingled, selective
  - How flow is controlled – wireline, remotely (intelligent completions)
  - Combinations of these – Multi-zone, horizontal fractured well completions (shale plays)