Elements of Tubing Selection

- Usually requires a nodal analysis program and some very good information about the well’s productivity over time.
- An error in the flow data can cause a quick error in the tubing sizing.

Production Tubing Design

1. Max and optimum flow rate
2. Max surface pressure (flowing and shut-in)
3. Corrosion potential over life of string
4. Erosion potential over life of the string
5. Stimulation factors
6. Tensile strength
7. Burst and collapse

Tubular String- 8 Design Factors

- **Tension – tube must stand its own weight in the running environment. Tubing must stand additional loads when pulling out or setting packers and forces due to temperature and pressure changes.**
- **Burst – maintain integrity with high internal tubing pressures with little or no annular pressure support.**
- **Collapse - maintain integrity with high annulus pressures with little or no internal pressure support.**
- **Compression – tube must stand compressive loads when setting some packers and in highly deviated wells or dog legs.**

Tubular String- 8 Design Factors

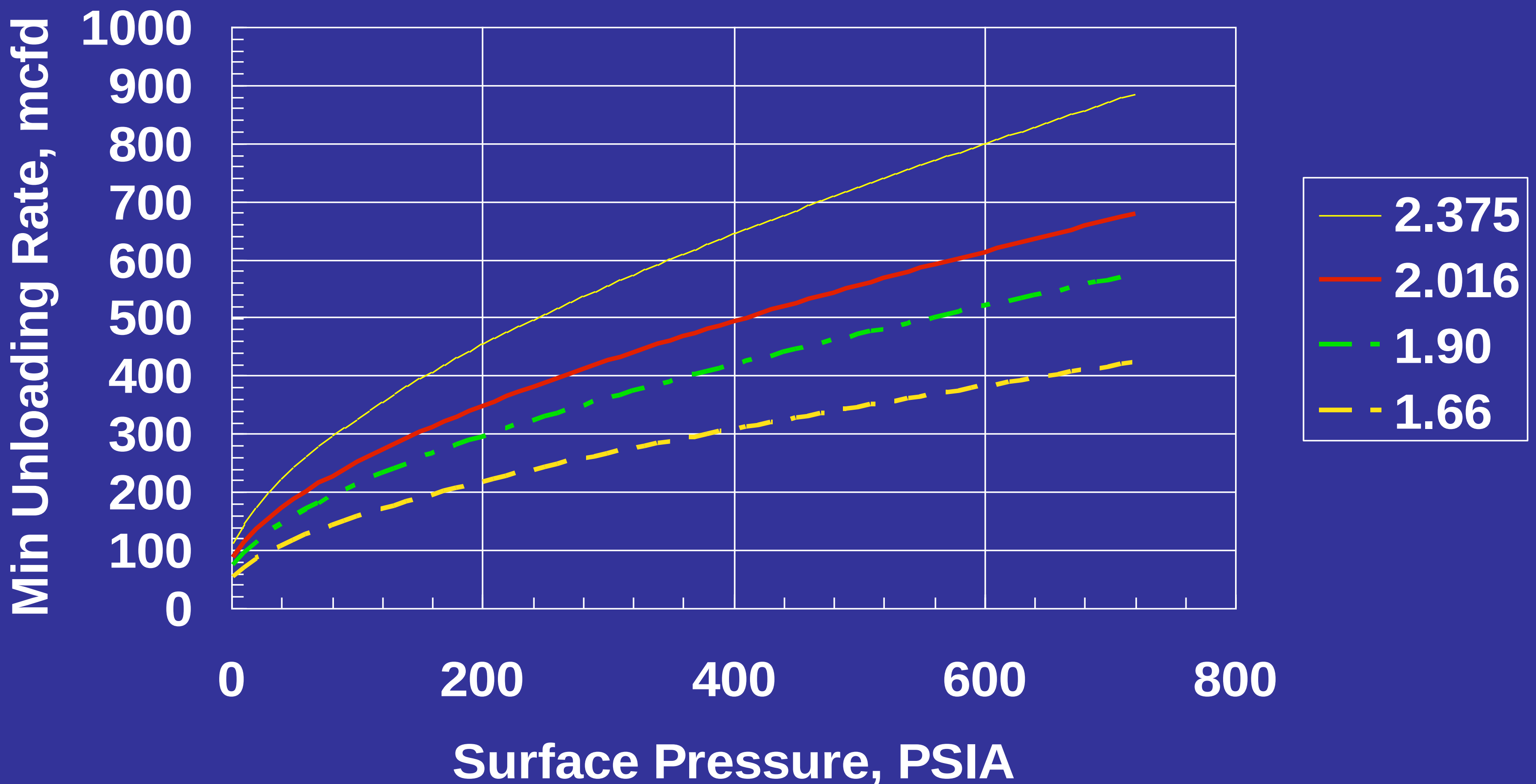
- **Couplings –** **free from leaks, maintain ID clearance, strength through bend areas and in compression and tension loads.**
- **Corrosion -** **tube must be designed to counter corrosion reactions with flowing fluids over its lifetime. CO_2, H_2S, acid, cracking, etc.**
- **Abrasion/Erosion –** **equipment must withstand abrasion and erosion loads over lifetime**
- **Stimulation Loads –** **The tubular must withstand loads from acids, fracturing or other stimulations**

Tubing Size Factors

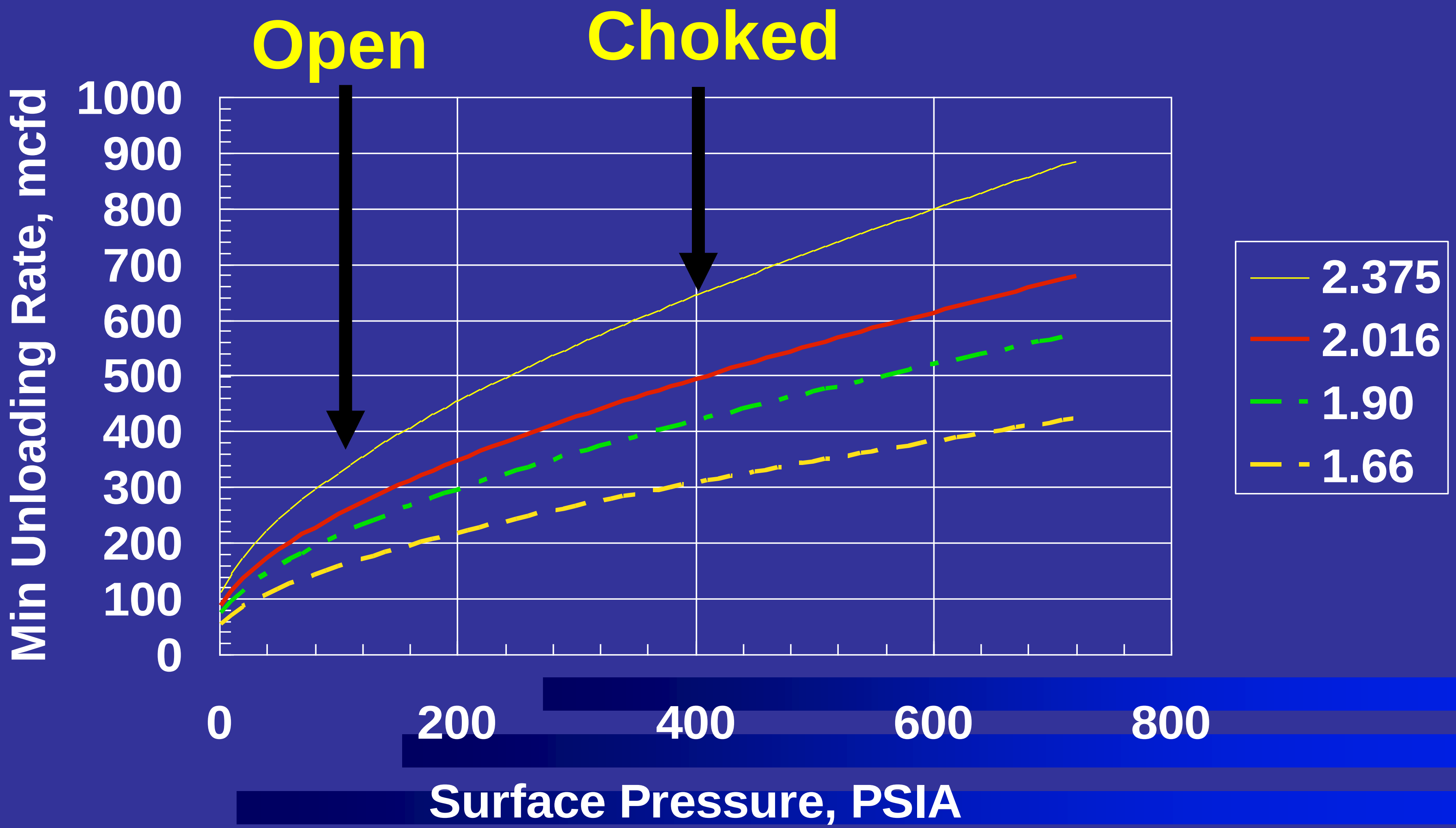
- Sized for natural gas lift – optimum use of expanding gas – IPR and TPC curves.
- Sized to prevent deposits – minimum flow level = 3.5 ft/sec.
- Sized to prevent liquid abrasion – maximum relative to density and reactivity.
- Sized to prevent particulate erosion – maximum relative to particulate size and velocity.

Typical Critical Unload Rates Mscf/d)

(based on Turner Correlation)

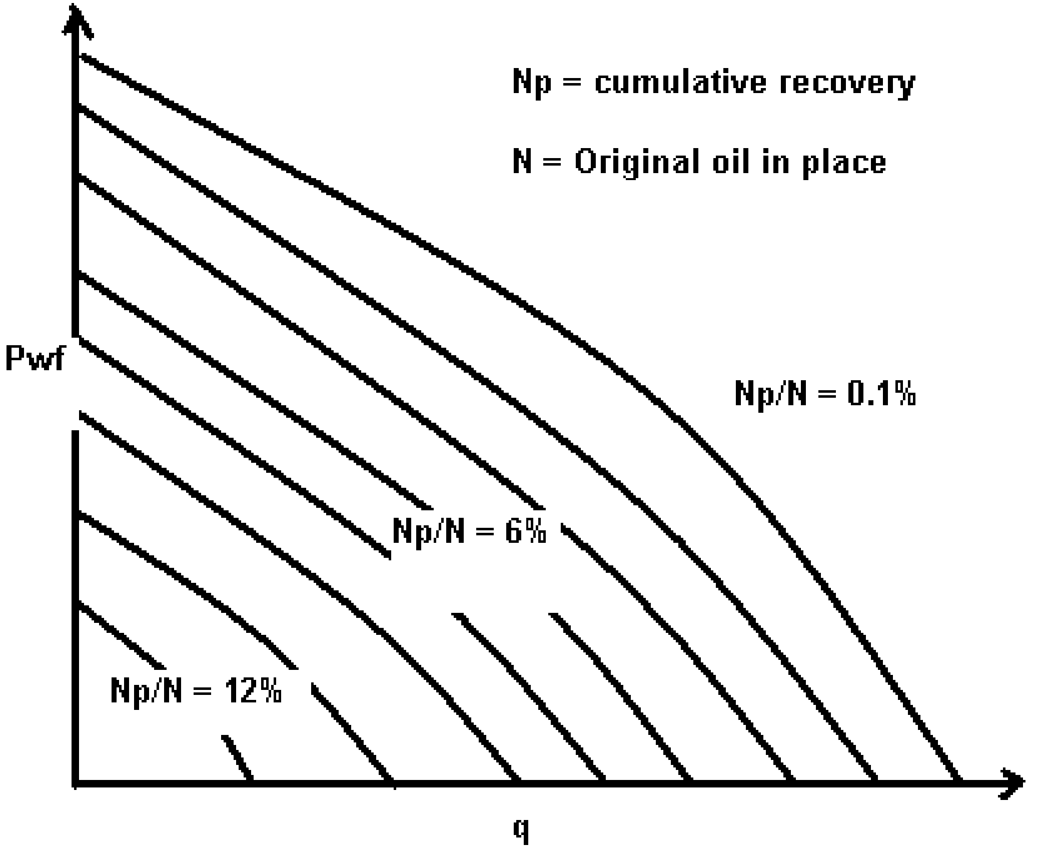


Effects of a Choke on Critical Rate

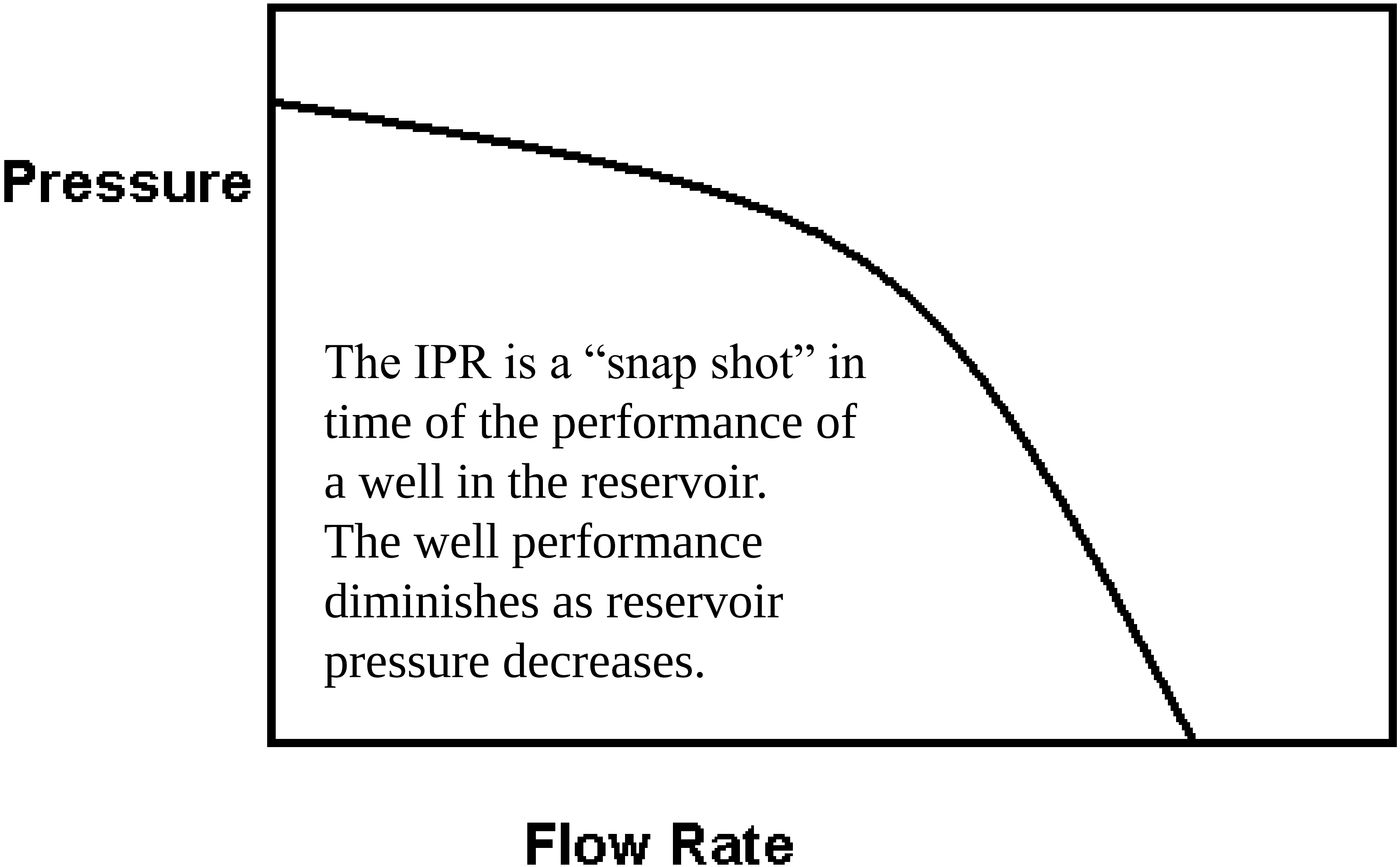


Inflow Performance Relationship

- For non linear (2 phase) flow

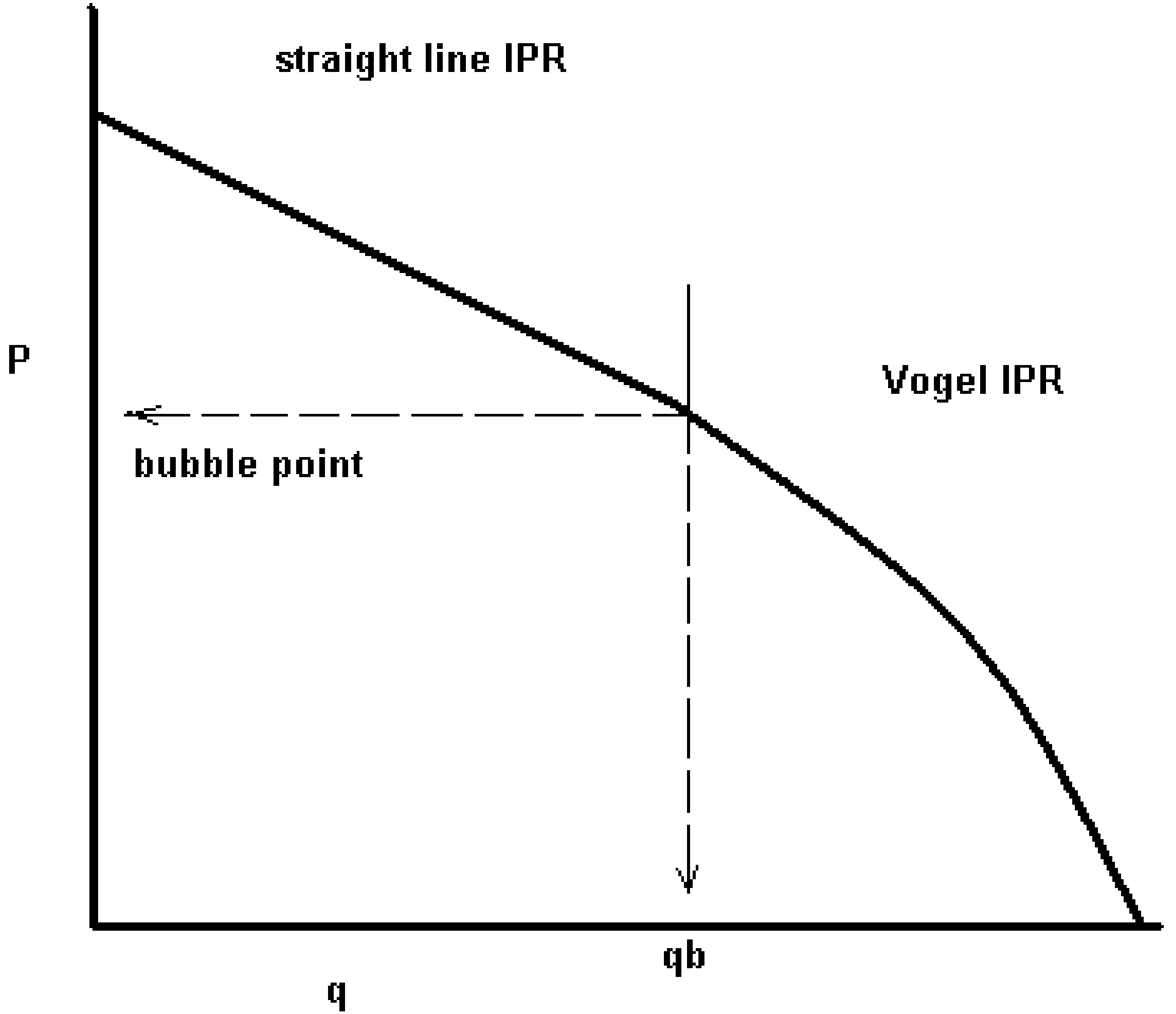


Inflow Performance Relationship, IPR



The IPR is a “snap shot” in time of the performance of a well in the reservoir. The well performance diminishes as reservoir pressure decreases.

When the average reservoir pressure is above the bubble point and the flowing bottom hole pressure is below the bubble point, a combined approach using straight line and Vogel will describe the process.



Vogel Calculations

- Vogel IPR Curve:

  $(q/q_{max}) = 1 - 0.2\,(P_{wf}/P) - 0.8\,(P_{wf}/P)^2$

- Straight line IPR

  $(q/q_{max}) = 1 - (P_{wf}/P)$

P_{wf} = bottom hole flowing pressure

P = maximum shut-in bottom hole pressure

Which Curve?

- If a sample of formation fluid (pressurized) is taken and analyzed for bubble point, then the decision can be made of what relationship to use.

Gas Well IPRs

- In gas wells, both fluid viscosity and compressibility are pressure dependent.
- Model is also complicated by high velocities around the wellbore that produce turbulent flow.
- Darcy model assumes laminar flow and is not valid for the pressure drops produced by turbulence in gas wells.

Non-Linear IPR (Gas)

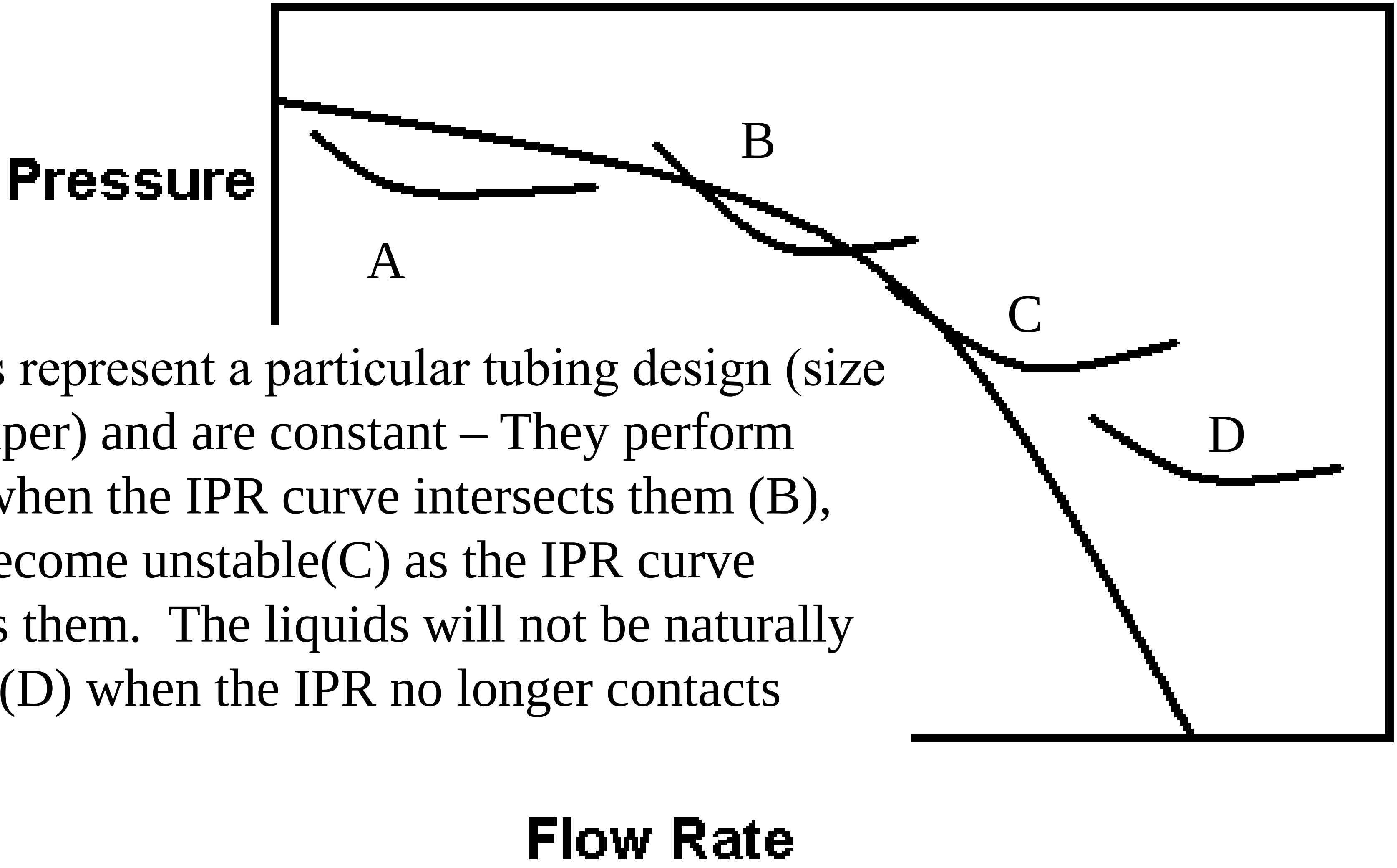
- $P^2 - Pwf = aq + bq^2$
  - Where
    - aq = pressure drop due to laminar (Darcy) flow
    - bq2 = pressure drop due to turbulent (non-Darcy) flow

The constants a and b can be derived from multi-rate well test or alternatively estimated from known reservoir and gas properties.

Tubular Sizing – IPR & TPC

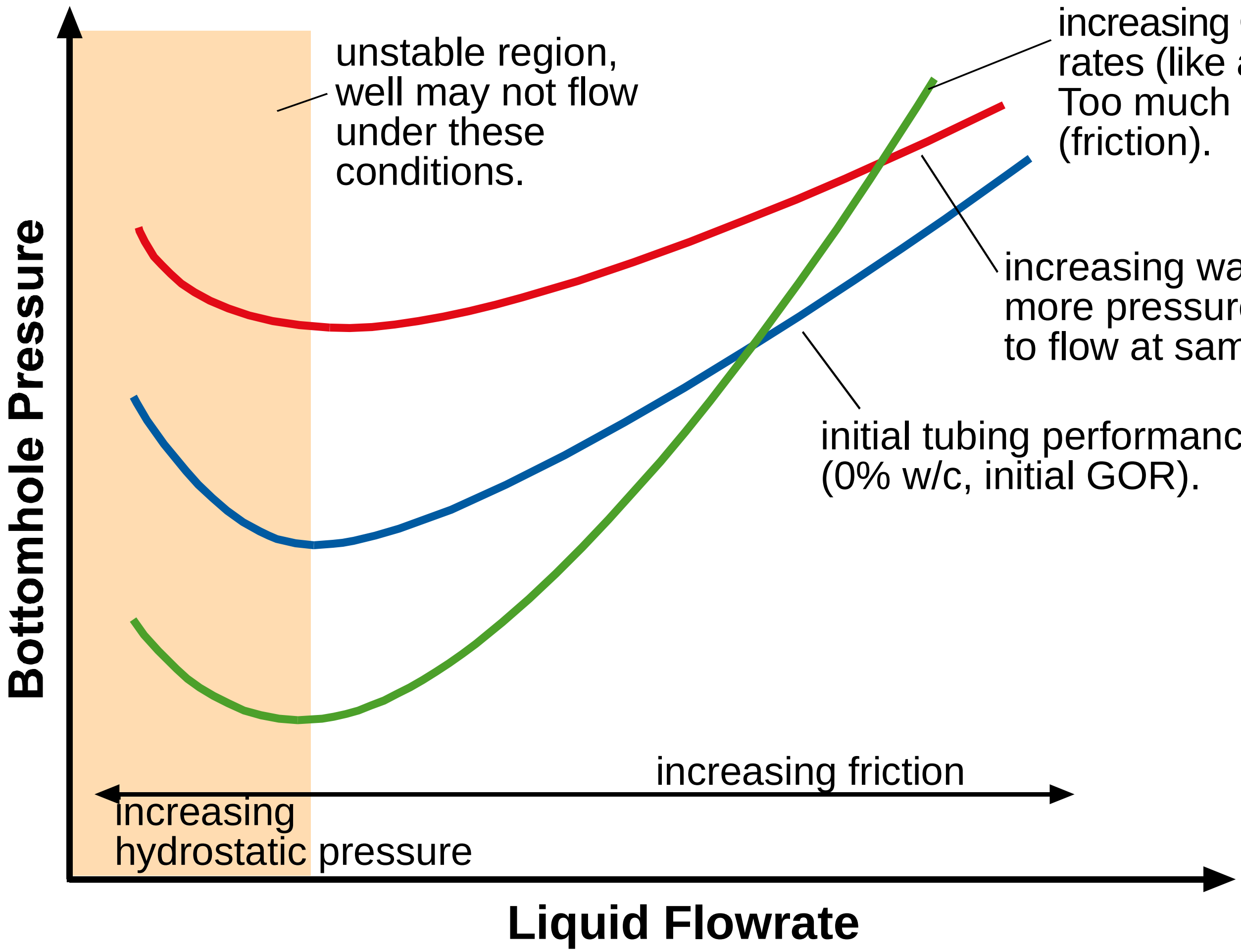
- Nodal analysis packages
- Tubing performance and Inflow performance curves

Tubing Performance Curves with Inflow Performance Relationship



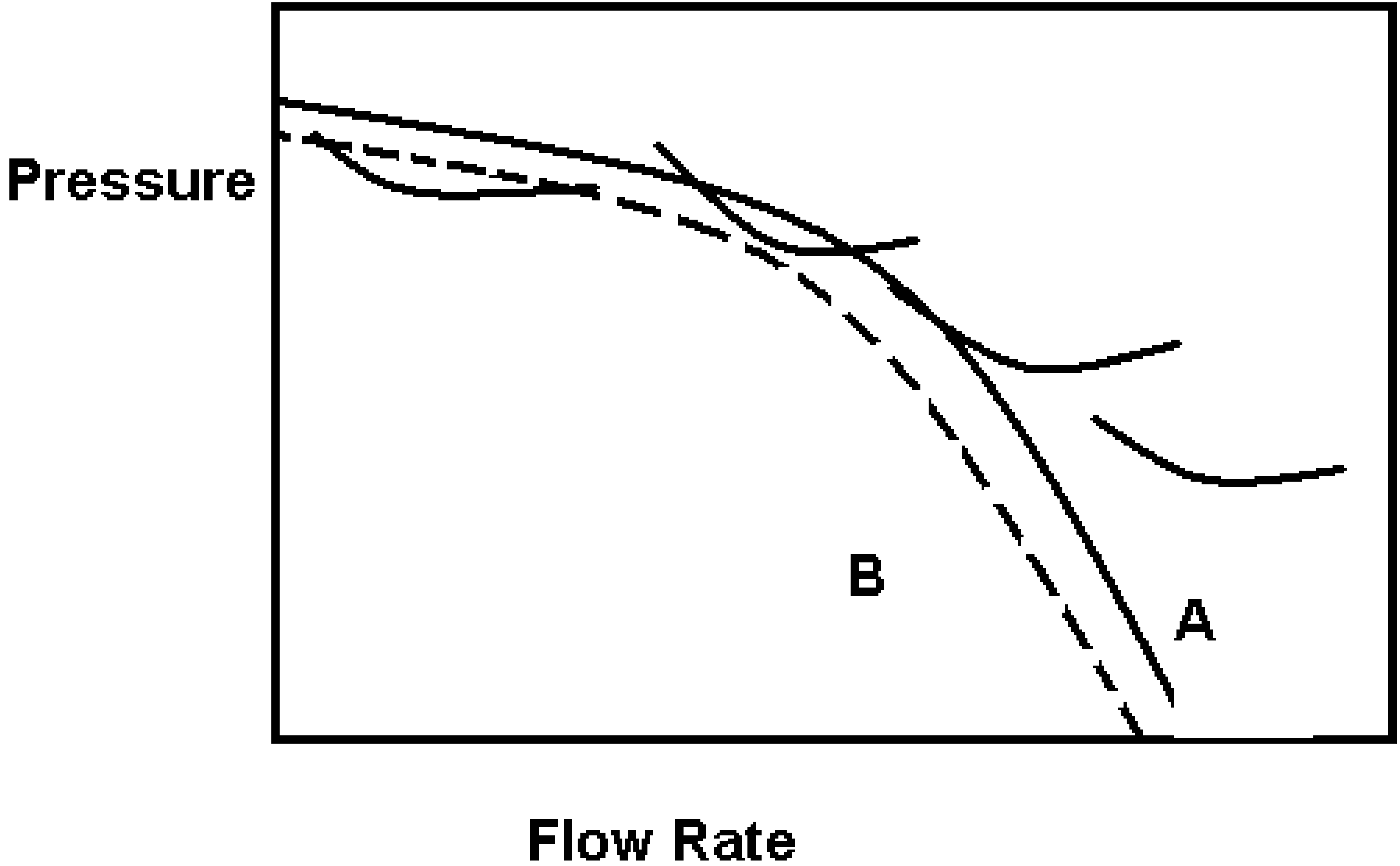
TPC's represent a particular tubing design (size and taper) and are constant – They perform well when the IPR curve intersects them (B), and become unstable(C) as the IPR curve passes them. The liquids will not be naturally lifted (D) when the IPR no longer contacts them.

Tubing Performance Curves



TUBING PERFORMANCE RELATIONSHIP

IPR Change After Some Reservoir Depletion



Where Do You Calculate CR… Surface or Bottom Hole?

Pres: 400#
Temp: 60 deg F
Tbg: 1 ¼" CT
Rate: 200 mscfd

Wellhead
Critical Rate: 180 mscfd

DON'T CALCULATE CRITICAL RATE AT SURFACE ONLY!!!

10,000' 1 ¼" CT

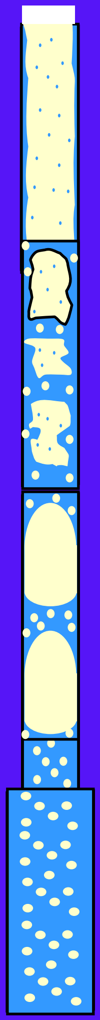
Pres: 900#
Temp: 200 deg F

Bottom of CT
Critical Rate: 220 mscfd

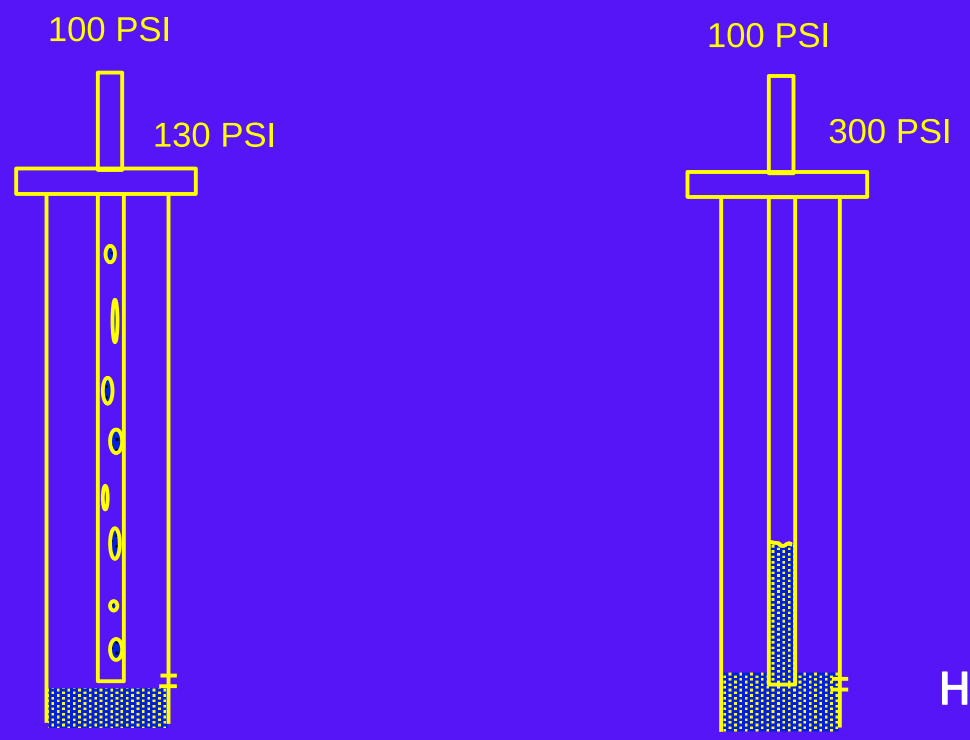
10,500' 3 ½" Csg to Perfs

Pres: 1100#
Temp: 200 deg F

Casing
Critical Rate: 1500 mscfd



Loaded Well Effects on IPR



Low FBHP

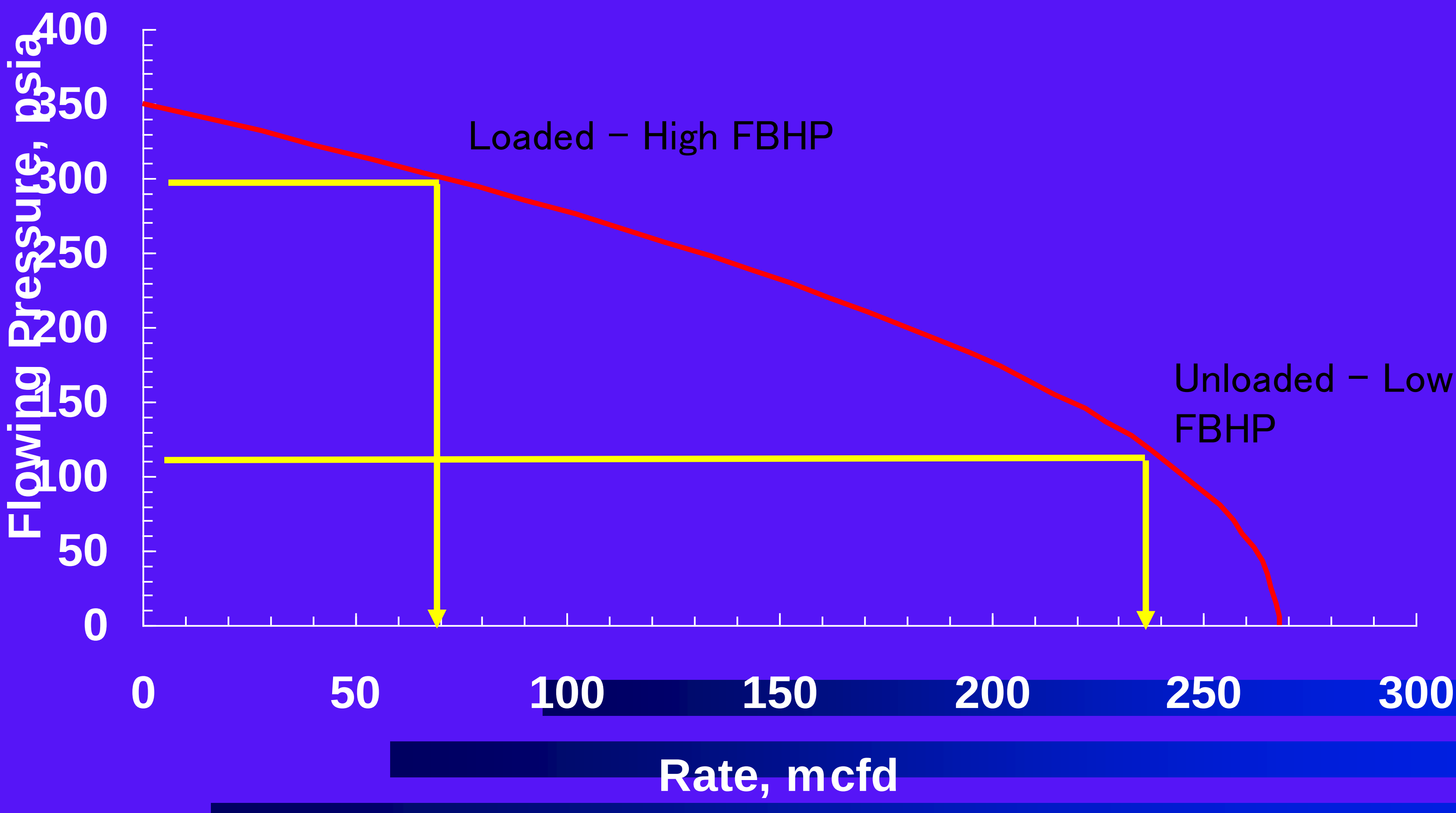
High FBHP

Normal

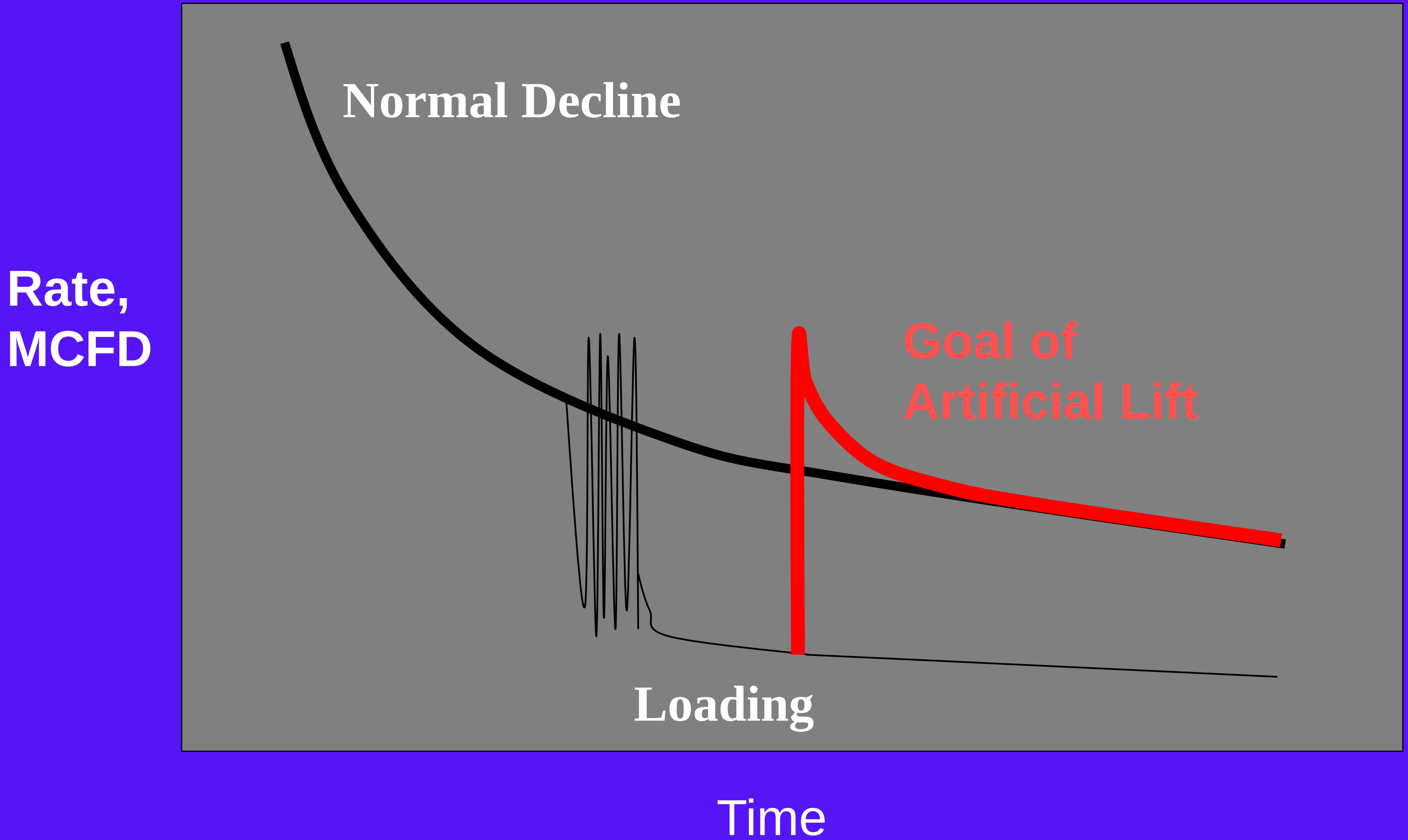
Loaded

Typical IPR Curve for a Gas Well

Loaded vs Unloaded

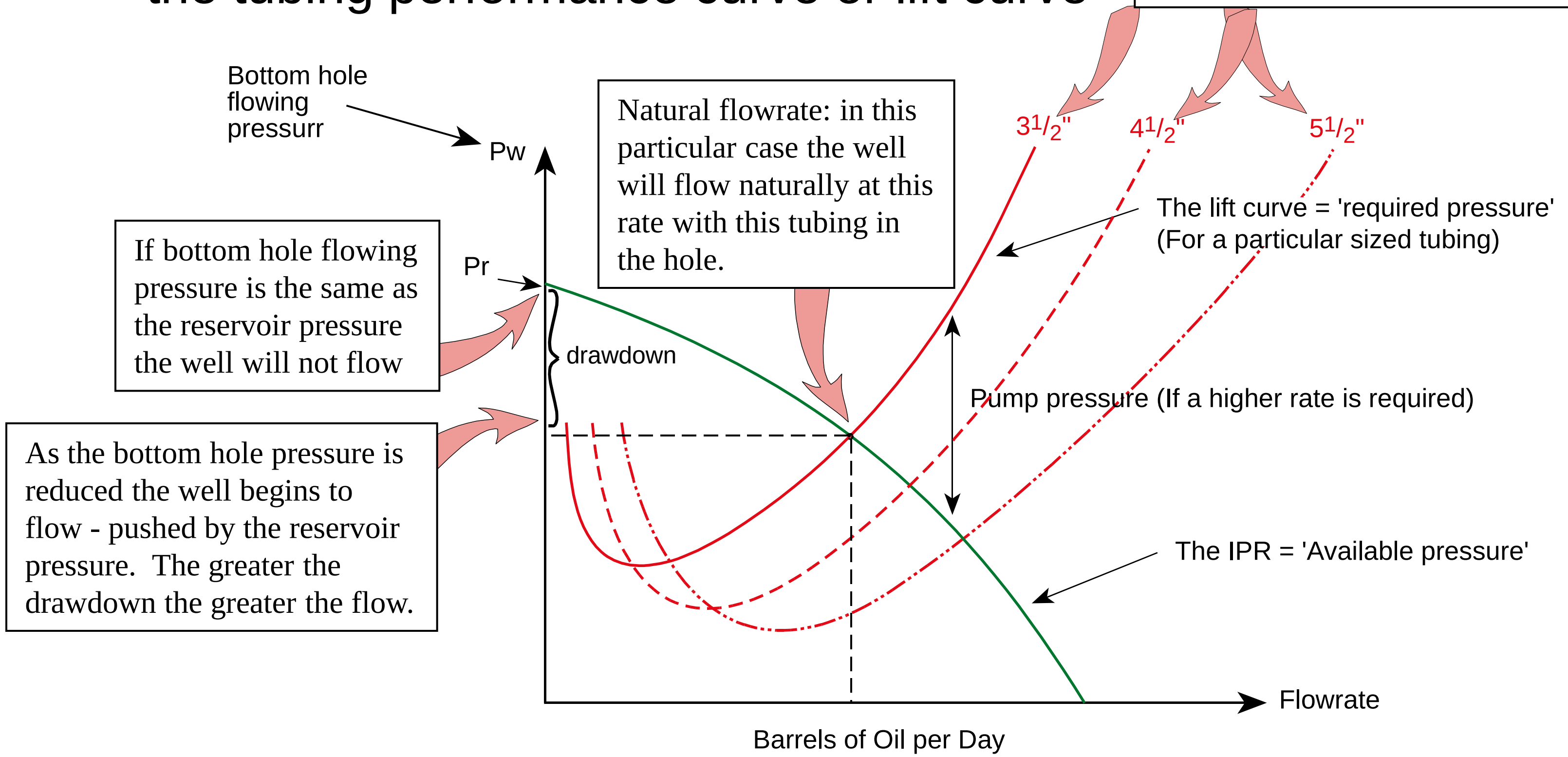


Effects of Artificial Lift on Production Decline



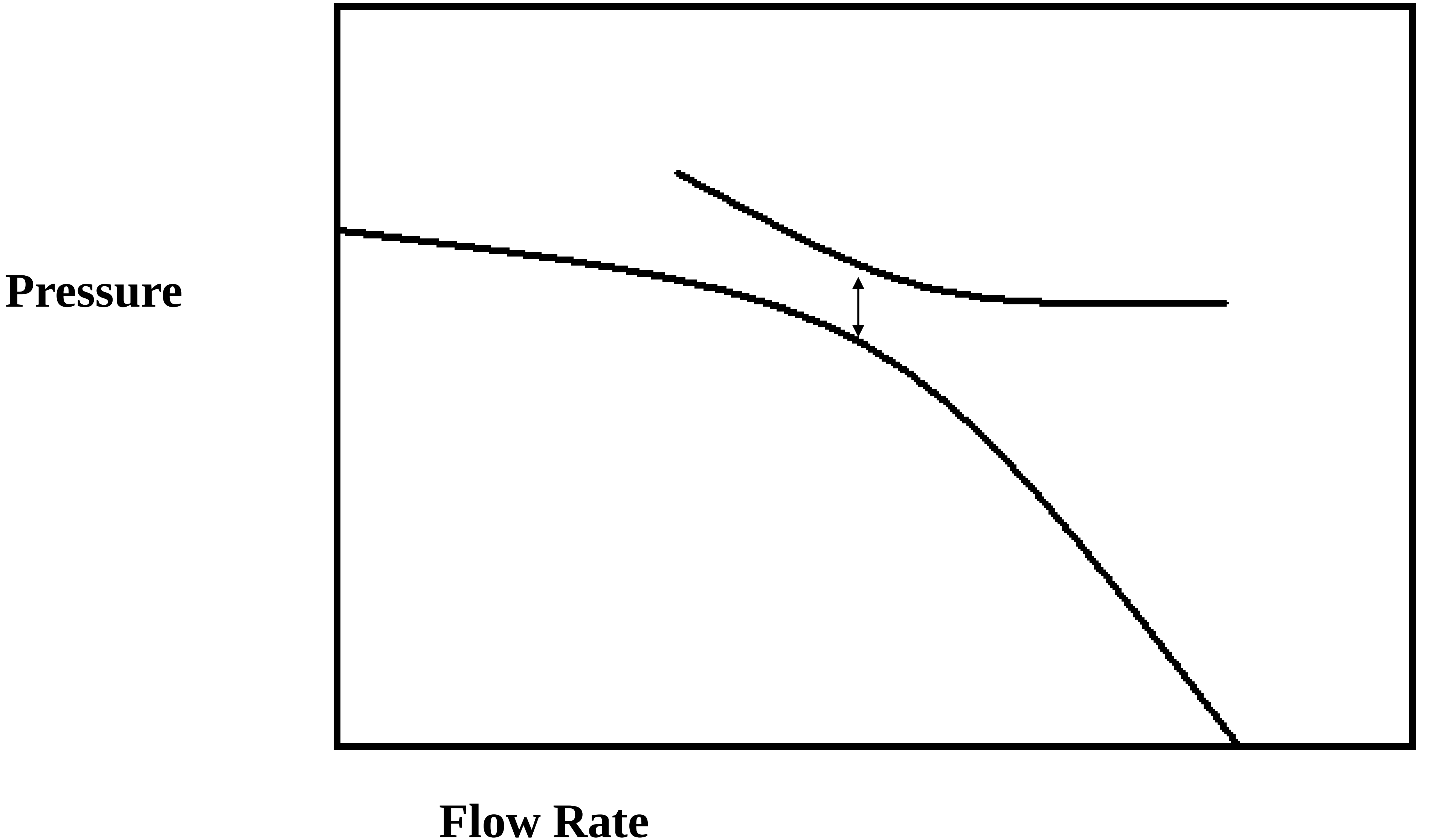
Production Rate and Tubing Sizing

- The pressure drops are plotted against flowrate to give
  - inflow performance relationship or IPR
  - the tubing performance curve or lift curve

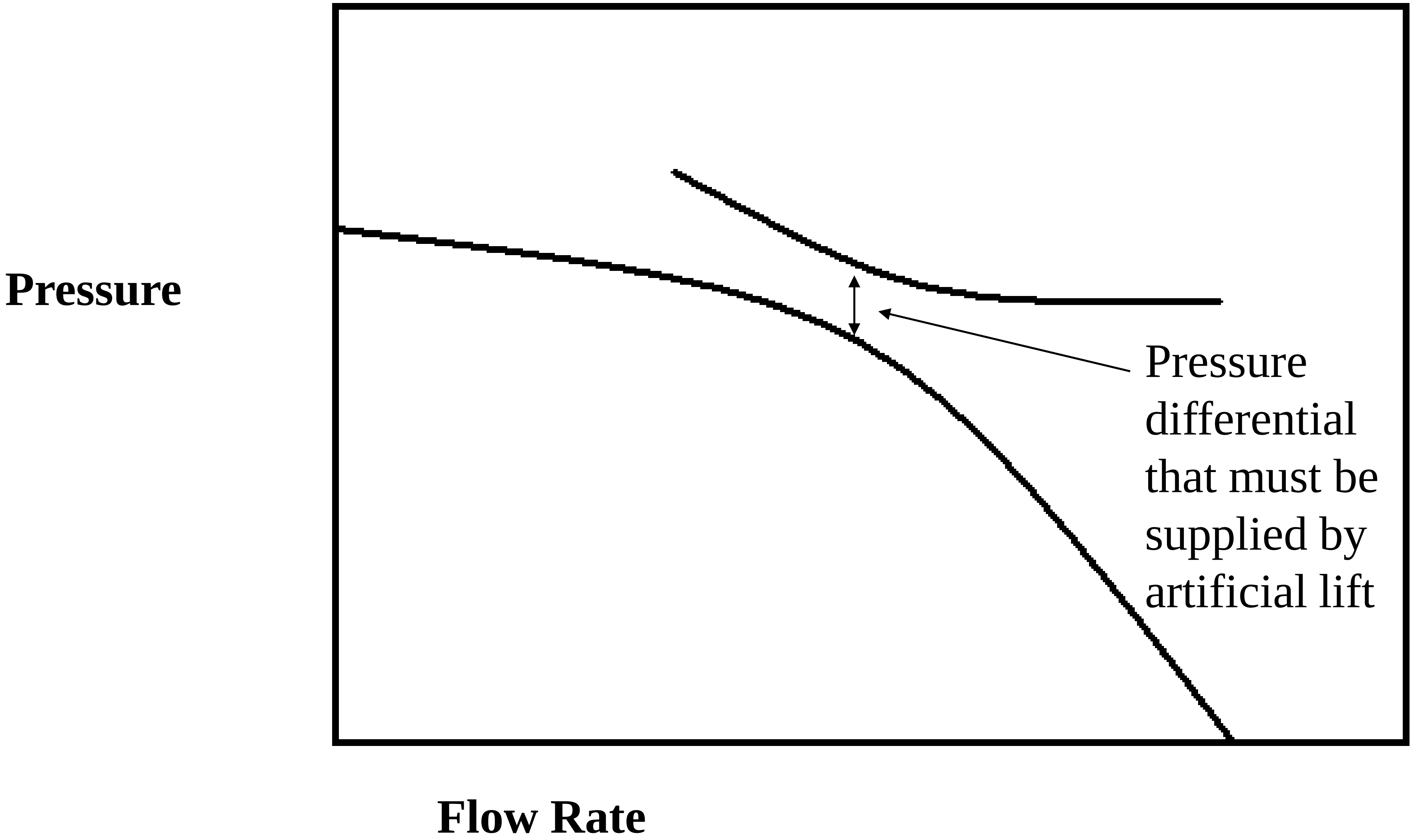


Inflow Performance Relationship (IPR) and tubing Performance Curves

What Happens When TPC and IPR Curves no longer meet?



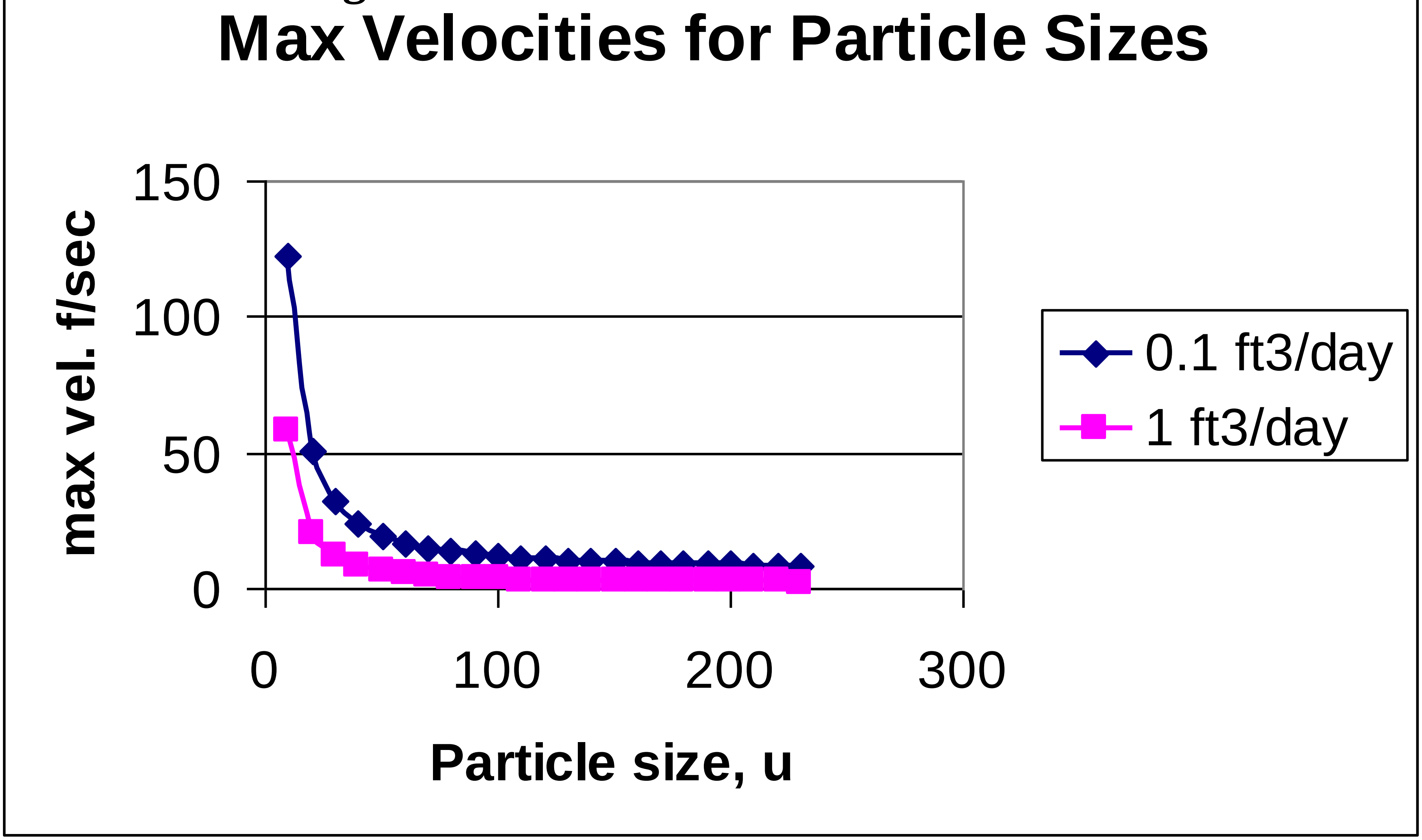
What Happens When TPC and IPR Curves no longer meet?

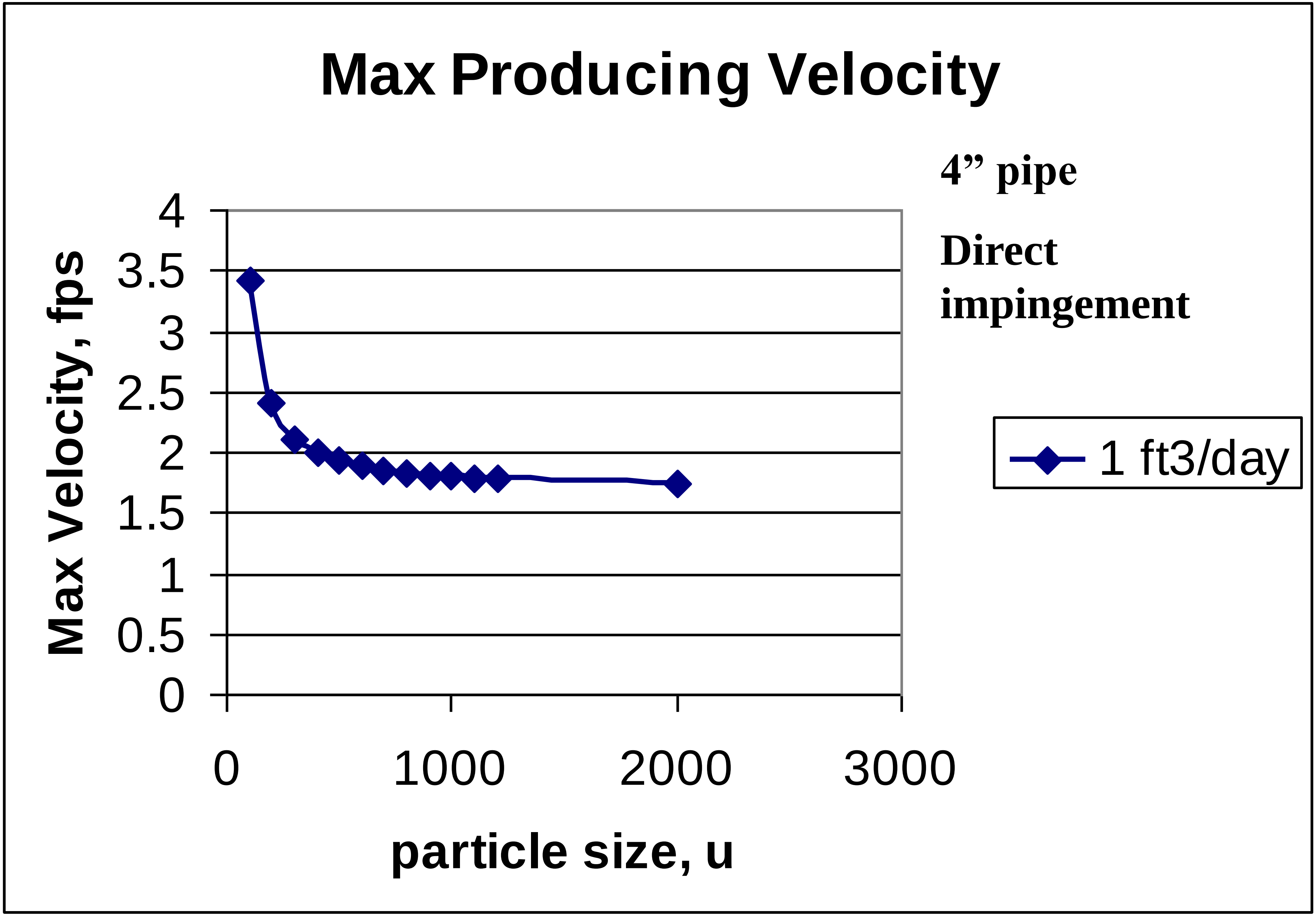


The Most Critical Problem?

- Solids in the flow.
  - Important factors:
    - **velocity of solids**
    - **density of solids**
    - **type of solids**
    - **size of solids**
    - **impengement surface (angle and type)**

Maximum flowing fluid velocity for increasing particle diameters. Although smaller particles do less damage than larger particles (less mass), the sheer number of small particles can still do a significant amount of damage.





Max Producing Velocity
4” pipe
Direct impingement
1 ft3/day
Max Velocity, fps
0
0.5
1
1.5
2
2.5
3
3.5
4
0
1000
2000
3000
particle size, u

Primary Erosion Locations

- sharp turns in the flow path
- where gas velocity is maximum
- eddy current and similar patterns
- constrictions in the flow path

Bubbles and Droplets

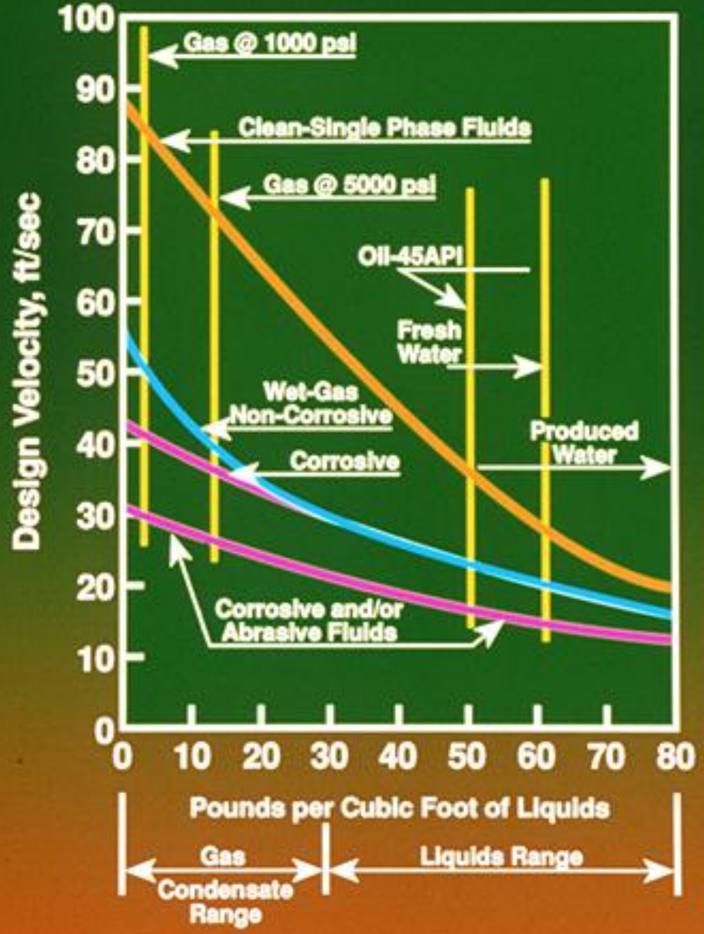
- Two problems:
  - cavitation: creation and collapse of bubbles. High energy area - striking erosion, even at low critical velocity phases.
  - bubble/droplet impact (mists, entrained drop). Problems: impingement of droplet or bubbles break down the corrosion resistant layer over the surface of the metal.

Maximum Velocities For Fluids

Conditions	Tubing Pressure 1000 psi	5000 psi
-		
Wet, non corrosive gas	85 fps	75 fps
Wet, corrosive gas	50 fps	40 fps
Wet,corros. & abrasive	30 fps	25 fps

There may be minimum velocities needed to prevent biofilms or other static fluid problems.

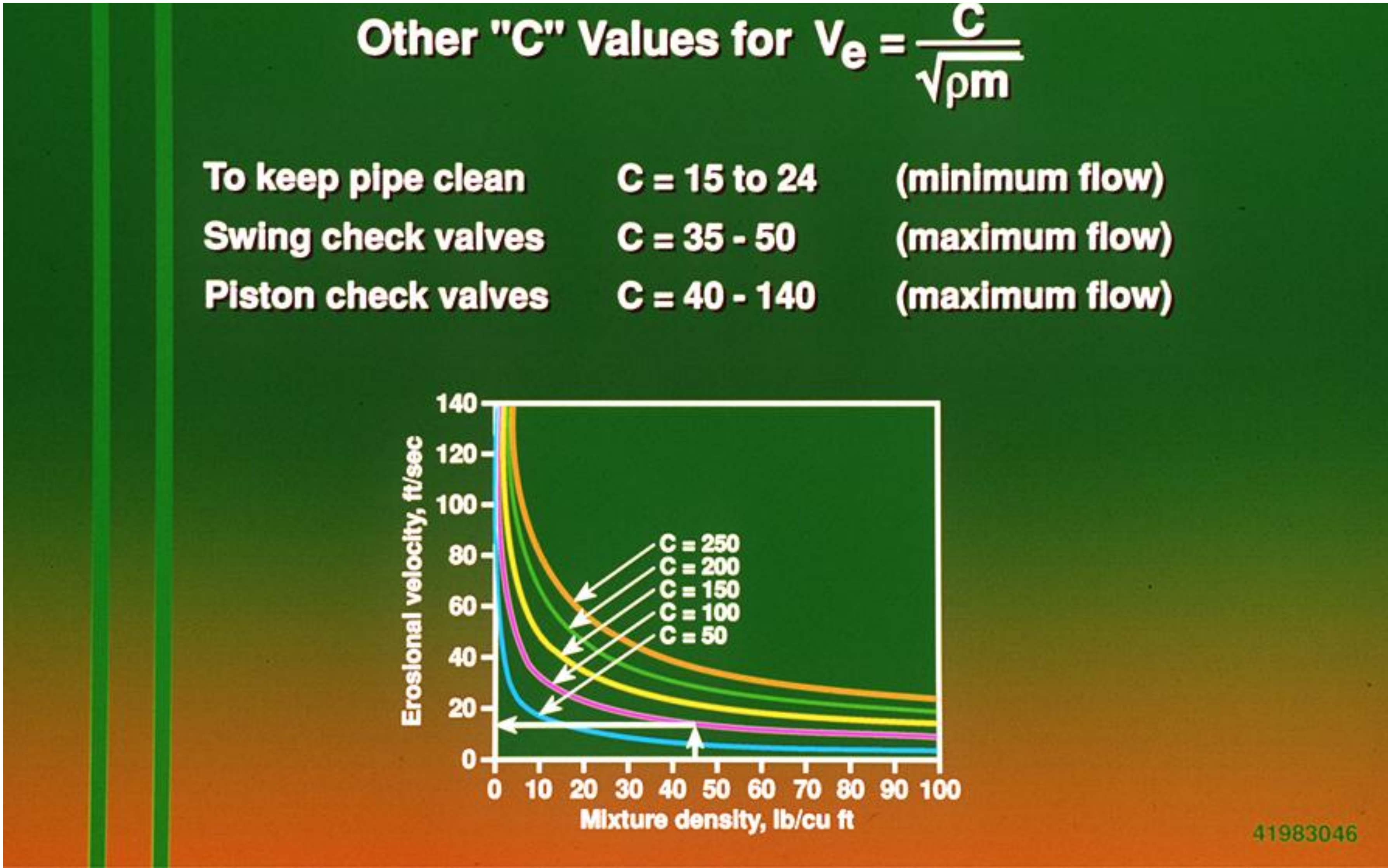
Tubing Design Velocities



Note the effect of increasing flowing fluid density on corrosion rate.

Also – presence of solids in the flowing fluids very significantly lowers the maximum permissible flow rate.

Critical or maximum velocities for flow using the API RP 14E equation. The variable is the C factor – for short lived projects, this factor may be 200 or more. It may also rise when CRA pipe is used or when coatings are compatible with flow.

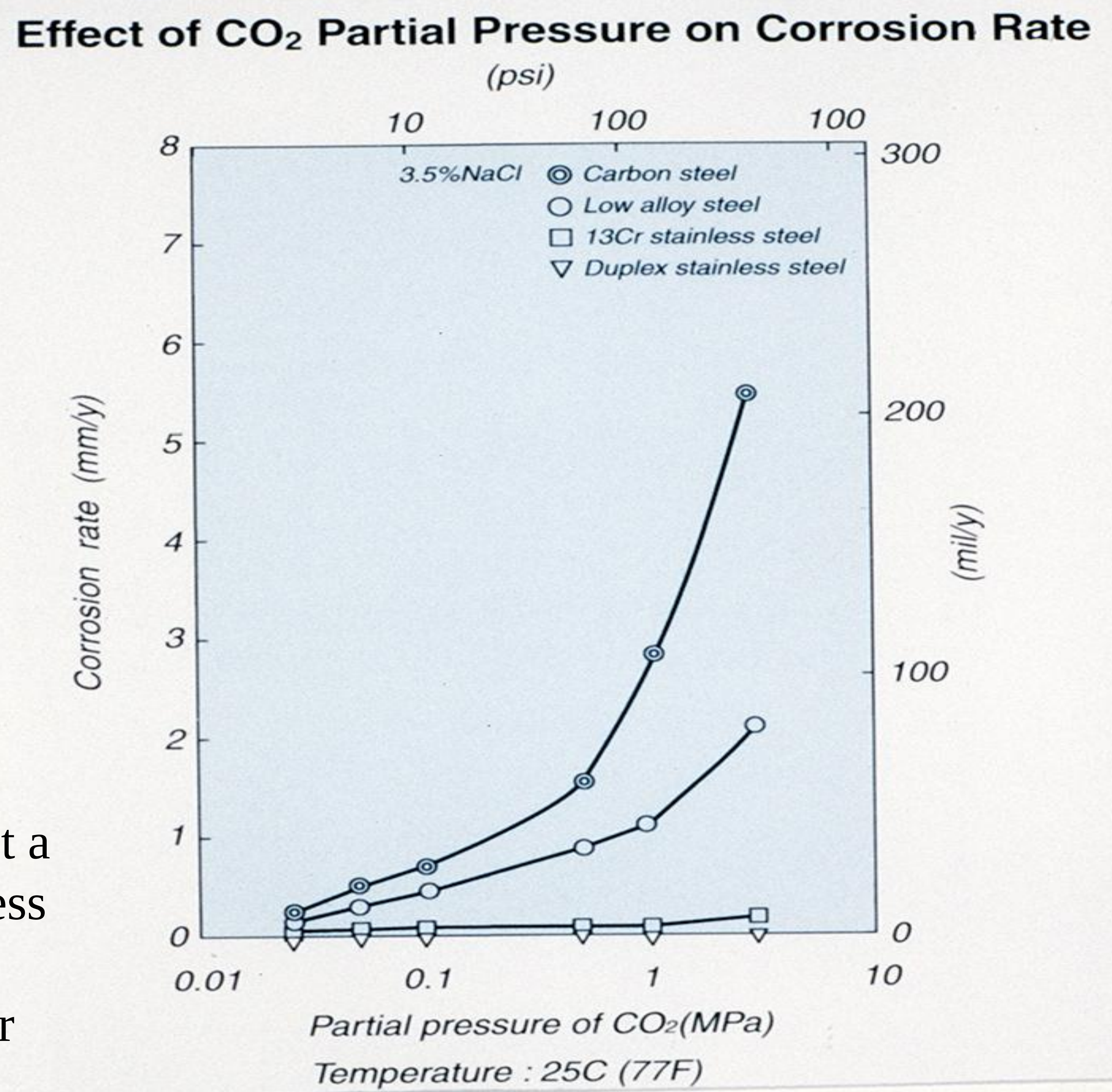


Corrosion Resistant Alloys

Steel	Location	Relative Cost
Carbon Steel	Wytch Farm, UK	1
13%Cr	S.N.Sea, Trinidad	3
Super 13%Cr	Rhum, Tuscaloosa	5
Duplex SS	Miller, T. Horse	8-10
Austenitic SS	Miller, Congo - Liners	12-15
Nickel Alloys	Middle East (825)	20
Hastelloy	Gulf Of Mexico (G3)	>20

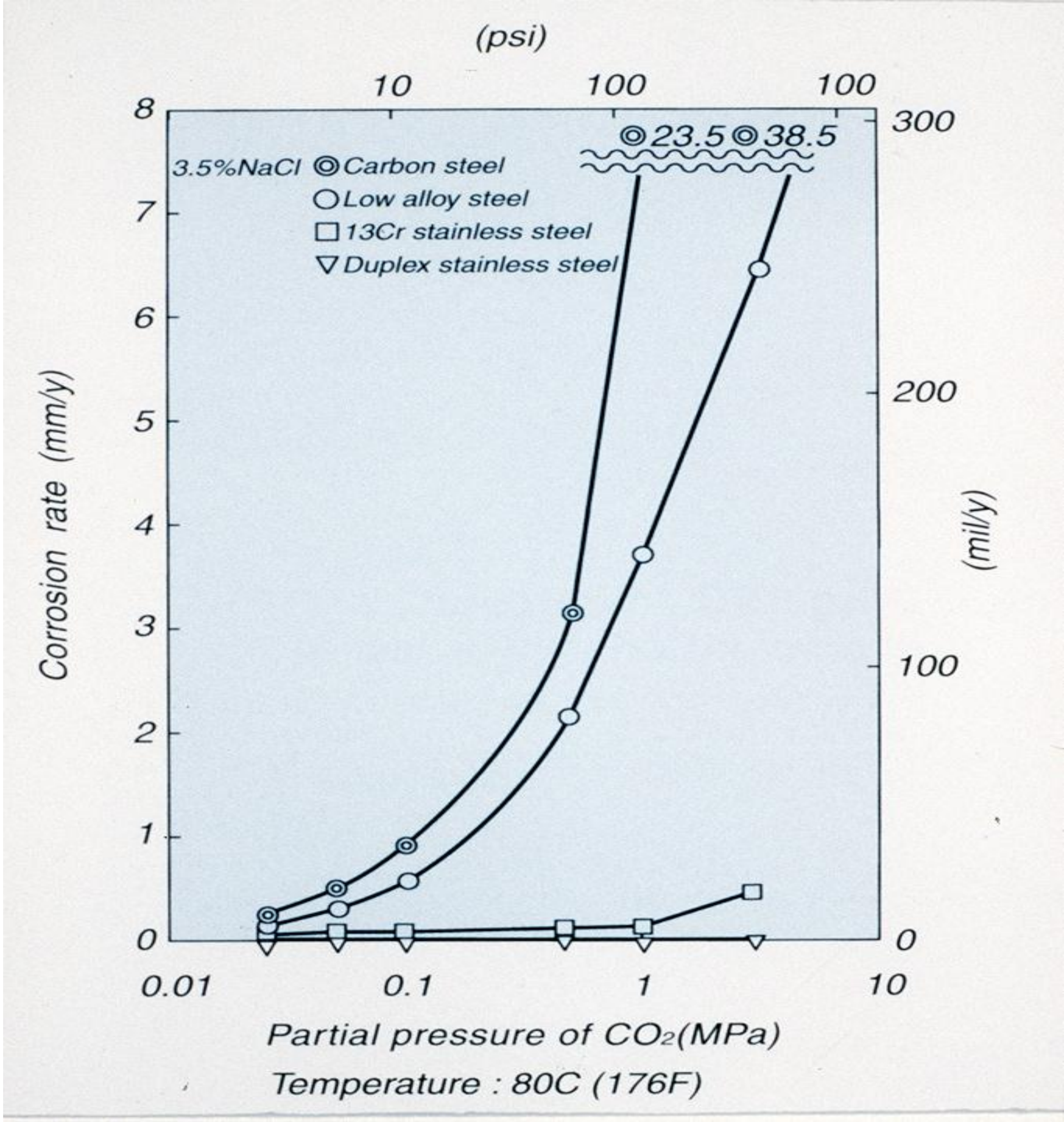
The corrosion rate of CO2 is a function of partial pressure, temperature, chloride presence of water and the type of material.

Corrosion rate in MPY – mills per year is a standard method of expression, but not a good way to express corrosion where pitting is the major failure.



Note the effect of the temperature on the corrosion rate.

Cost factors between the tubulars is about 2x to 4x for Chrome-13 over low alloy steel and about 8x to 10x for duplex (nickel replacing the iron).



Tubing Selection Criteria

- Sweet Non CO2 Service
- Sweet CO2 Service
- Sour Service
- High flow rates (high C factors)
- Erosive Service
- Stimulation tolerant
- Water injection wells

Tubular Selection Criteria

- Embrittlement
  - **hydrogen**
  - **chloride stress cracking**
- Weight Loss Corrosion
  - **H_2S-CO_2-H_2O-NaCl systems**
  - **CO_2-H_2O-NaCl**
- **Localized Corrosion**
- **Acidizing**
- **Galvanic**
- **Strength**
- **Cost and availability**

Sweet Well Materials

Equip.	Low Alloy Steels	Chrome or low CRA	Duplex, Super Duplex, 718, 725, 825 or 925
Well Heads	Acceptable	Acceptable	Severe Conditions
Tubing Hanger	Acceptable	Acceptable	Severe Conditions
Tubing	Most low perf. apps. CO_2 pp limits use	CO_2 service, limited protect. to O_2 & high Cl^- brines	Severe Conditions
Profiles		8 chrome common	Severe Conditions
ScSSVs		Application dependent	Severe Conditions
Packer	Strength & corrosion?	Application dependent	Severe Conditions
Sand Screens		Typical to 60C/140F,	Alloy 825

Source – Best Prac. Aug 2001, John Martins, et.al.

Sour Service Materials

Equip.	Low Alloy Steels	Chrome or low CRA	Duplex, Super Duplex, 718, 725, 825 or 925
Well Heads	Acceptable in low corrosion	Acceptable within NACE guidelines	Low temp / low strength apps.
Tubing Hanger	Acceptable in low corrosion	Acceptable within NACE guidelines	Low temp / low strength apps.
Tubing	Most low perf. apps. CO_2 pp limits use	NACE guidelines, O_2 & Cl brine limited protect.	Low temp / low strength apps.
Profiles		8 chrome common	Low temp / low strength apps.
ScSSVs		Super 13 and mtls within Nace guidelines	Low temp / low strength apps.
Packer	Strength & corrosion?	Application dependent	Low temp / low strength apps.
Sand Screens		SS316L Typical to 60C/140F,	Alloy 825

Materials for Injection/Disposal Service

Equip.	Low Alloy Steels	Chrome or low CRA	Linings
Tubing	Accept. in low O_2 (<20 ppb)	Chrome 13 not normally recommended	Good if within temp limits
Profiles		8 chrome common, higher alloy better	
ScSSVs		CRA selected for application	
Packer	Strength & corrosion?	CRA selected for application	

Special Applications – Deliquification of Gas Wells

- Turner and Coleman analysis

Turner Critical Velocity For Gas Wells

$V_{\mathbf{crit}} = 1.92\ [(\sigma^{\mathbf{1/4}}\ (\rho_{\mathbf{L}}\text{-}\rho_{\mathbf{g}})^{\mathbf{1/4}}\ /\ \rho_{\mathbf{g}}^{\frac{1}{2}})]$

$V_{\mathbf{crit}}$ = minimum gas velocity, ft/sec

σ = surface tension, dynes/cm

$\rho_{\mathbf{L}}$ = liquid density, lb/ft$^{\mathbf{3}}$

$\rho_{\mathbf{g}}$ = gas density, lb/ft$^{\mathbf{3}}$

σ = surface tension, dynes/cm: condensate is 20 and water is 60 dynes/cm

$\rho_{\mathbf{L}}$ = liquid density, lb/ft$^{\mathbf{3}}$: condensate is 45 and water is 67 lb/ft$^{\mathbf{3}}$

$\rho_{\mathbf{g}}$ = gas density, lb/ft$^{\mathbf{3}}$: function of pressure and temperature

Critical Velocity to Keep a Gas Well Unloaded - (Turner, W.O., Dec. 1966)

$$v_{gcond} = [4.02(45-0.0031p)^{0.25}]/[(0.0031)\,p^{0.5}]$$

$$v_{gwater} = [5.62(67-0.0031p)^{0.25}]/[(0.0031)\,p^{0.5}]$$

where:

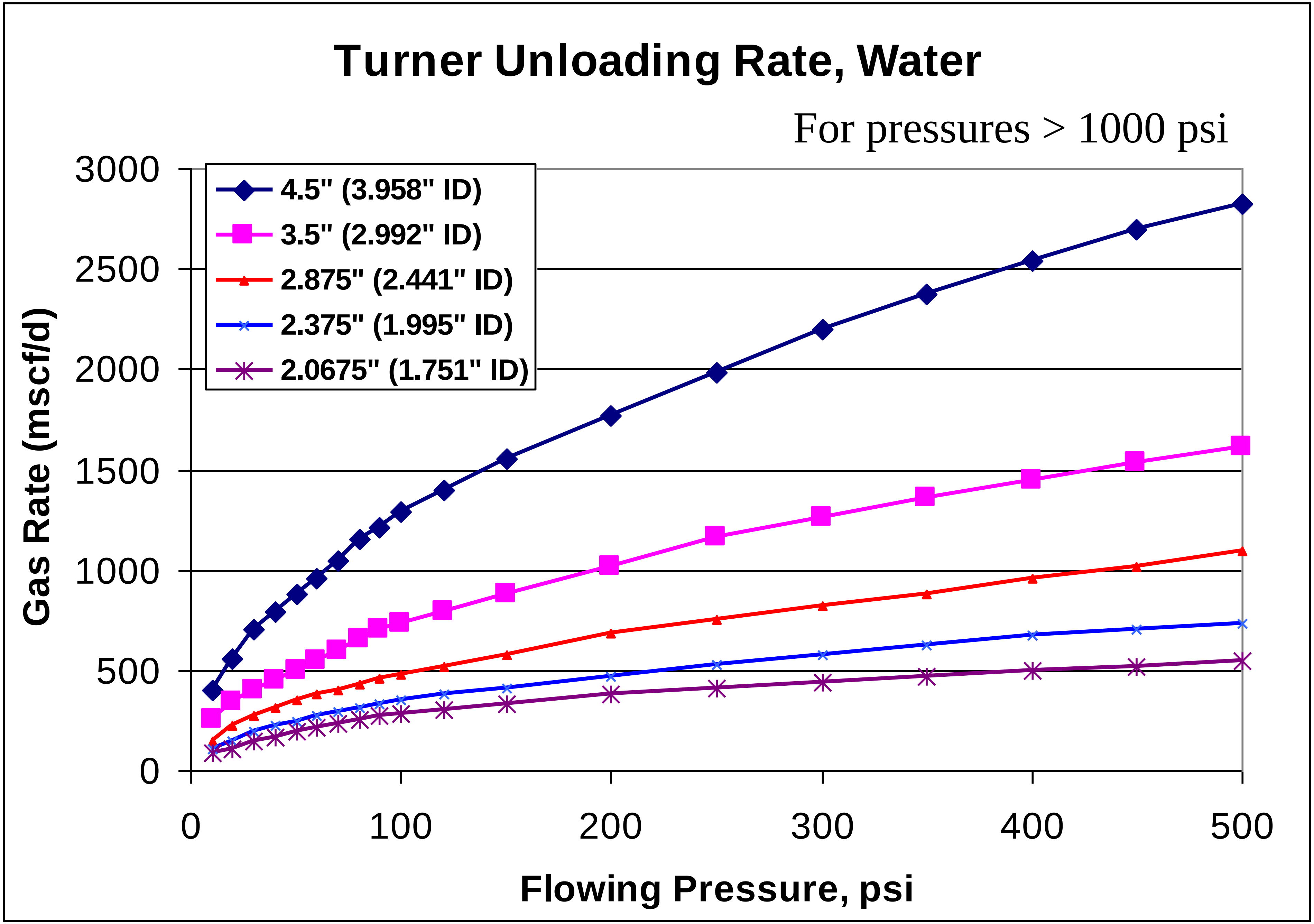
v = critical gas velocity in tbg for unloading, fps

p = surface pressure of well, psia

Gas is 0.6 gravity and gas temperature is 120F (49C)

For flow velocities above the critical rate, liquid drops are carried upward by the gas for well deviations less than about 20 degrees. For flow below the critical, water may not be carried out of the well or may produce in slugs. The well may continue to flow, but at a reduced rate due to the back pressure exerted by the liquid head.

SPE: Turner, et. al., JPT Nov 1969.



Source – J. Lea, Texas Tech, Turner Correlations.

Critical Gas Flow Rate

$Q = [3.06\ p\ v_g A]\ /\ [(T+460)Z]$

where:

- **Q = critical gas flow rate in mm scf/d, to lift liquid**
- **p = surface pressure in psia**
- **vg = critical gas vel, fps (water or condensate)**
- **A = cross sectional area of the tubing, ft2, =**
- **A = [3.14 d^2] / [(4) (144)]**
- **T = avg flowing temp in ^oF**
- **Z = gas factor**

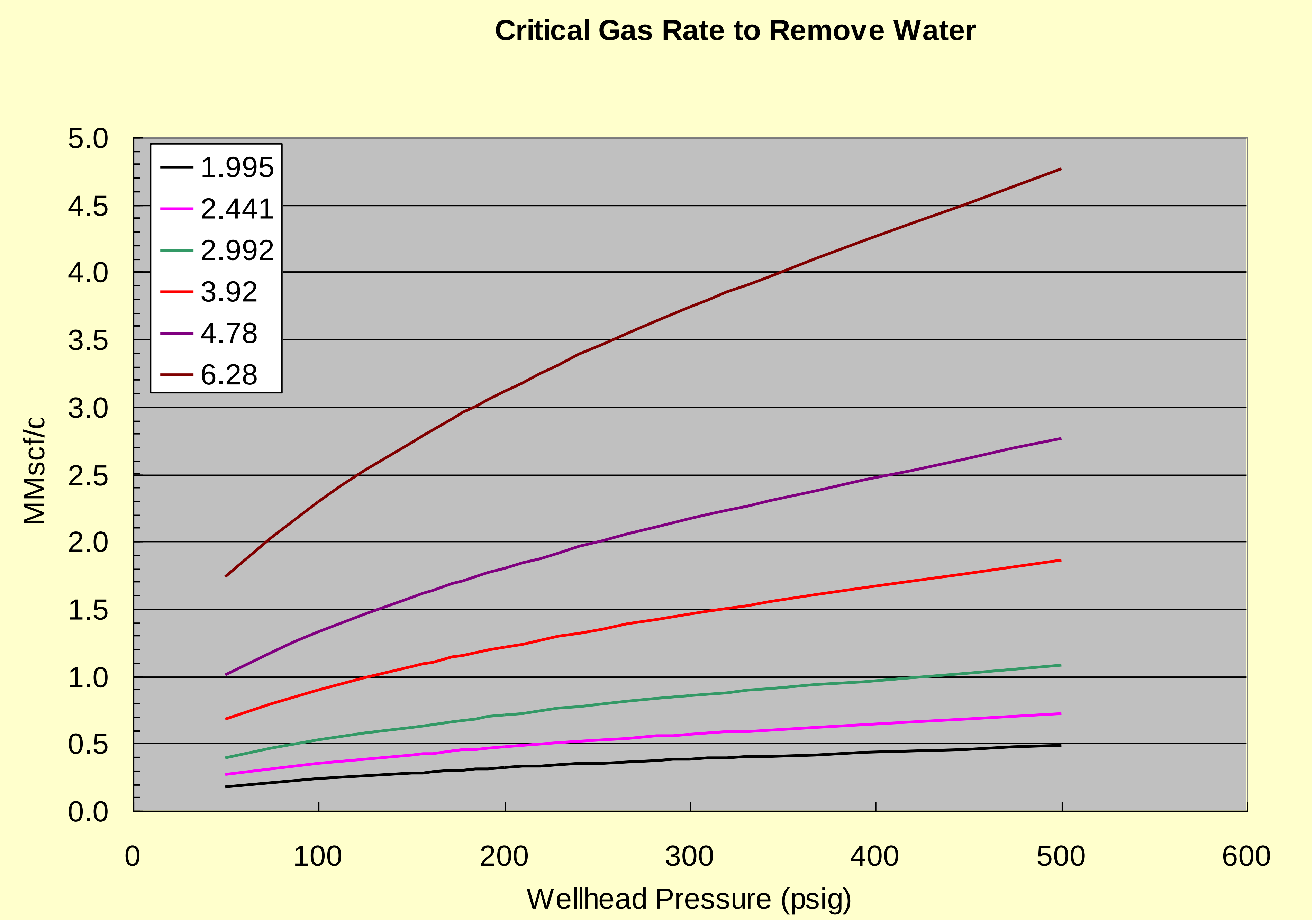
For Pressures greater than 1000 psi

Critical Diameter for Lift

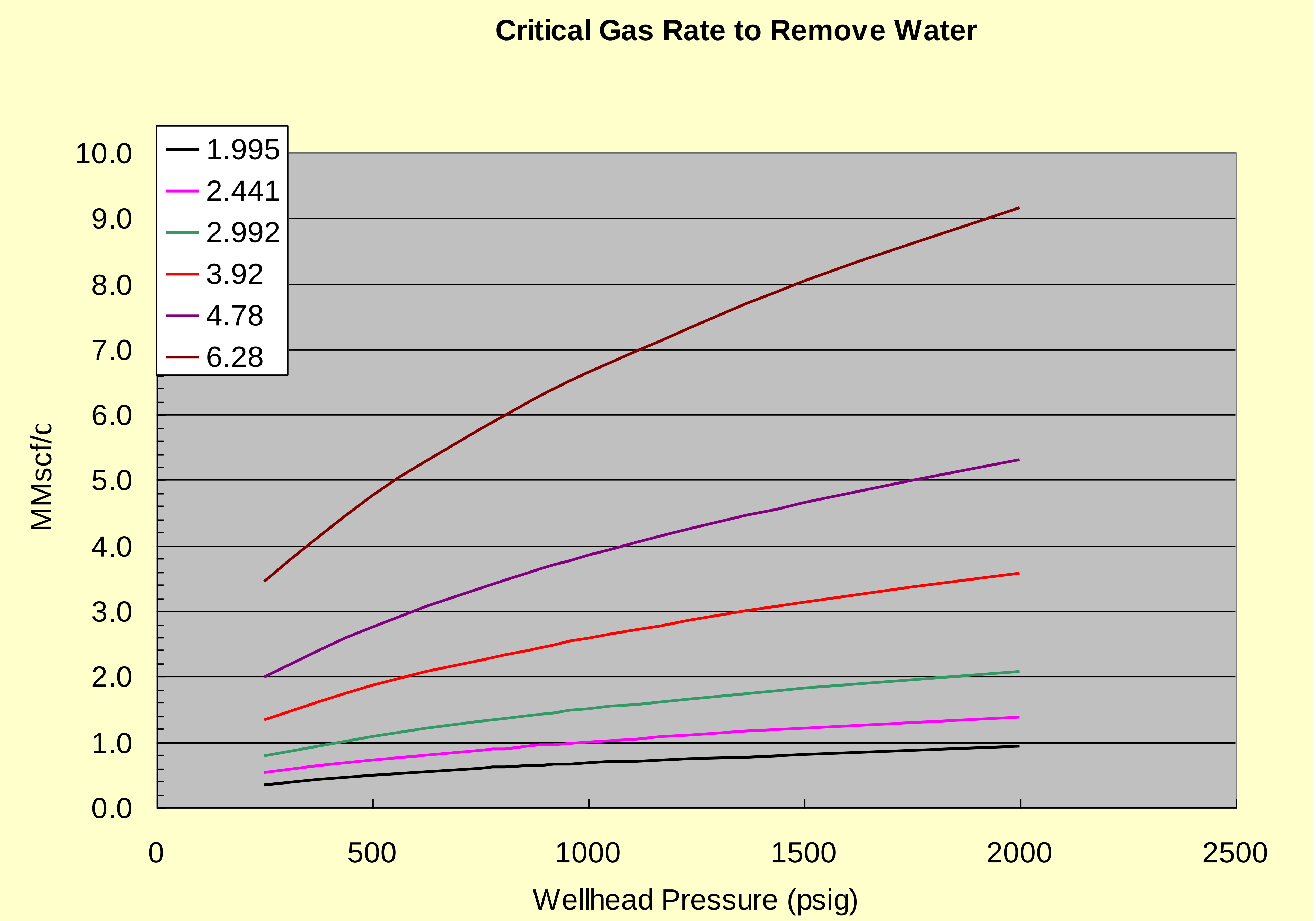
$$\mathbf{d = [\{(59.92)(Qg)(T+460)Z\} / \{(p)(vg)\}]^{0.5}}$$

Where:

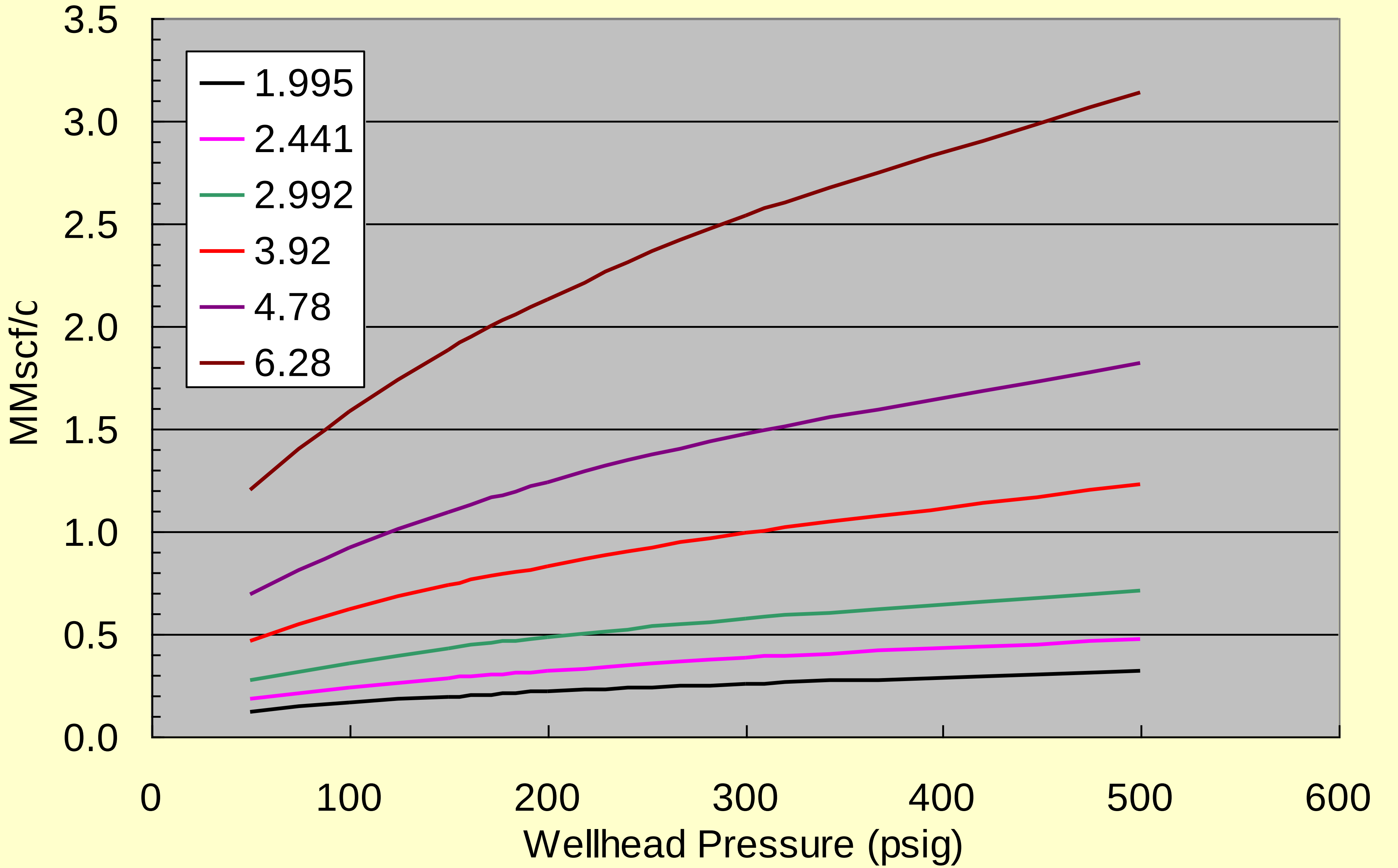
- Qg = critical gas rate, mmscf/d
- T = average flowing temp, ºF
- Z = gas factor
- p = surface pressure in psia
- vg = critical gas velocity to lift liquid, fps

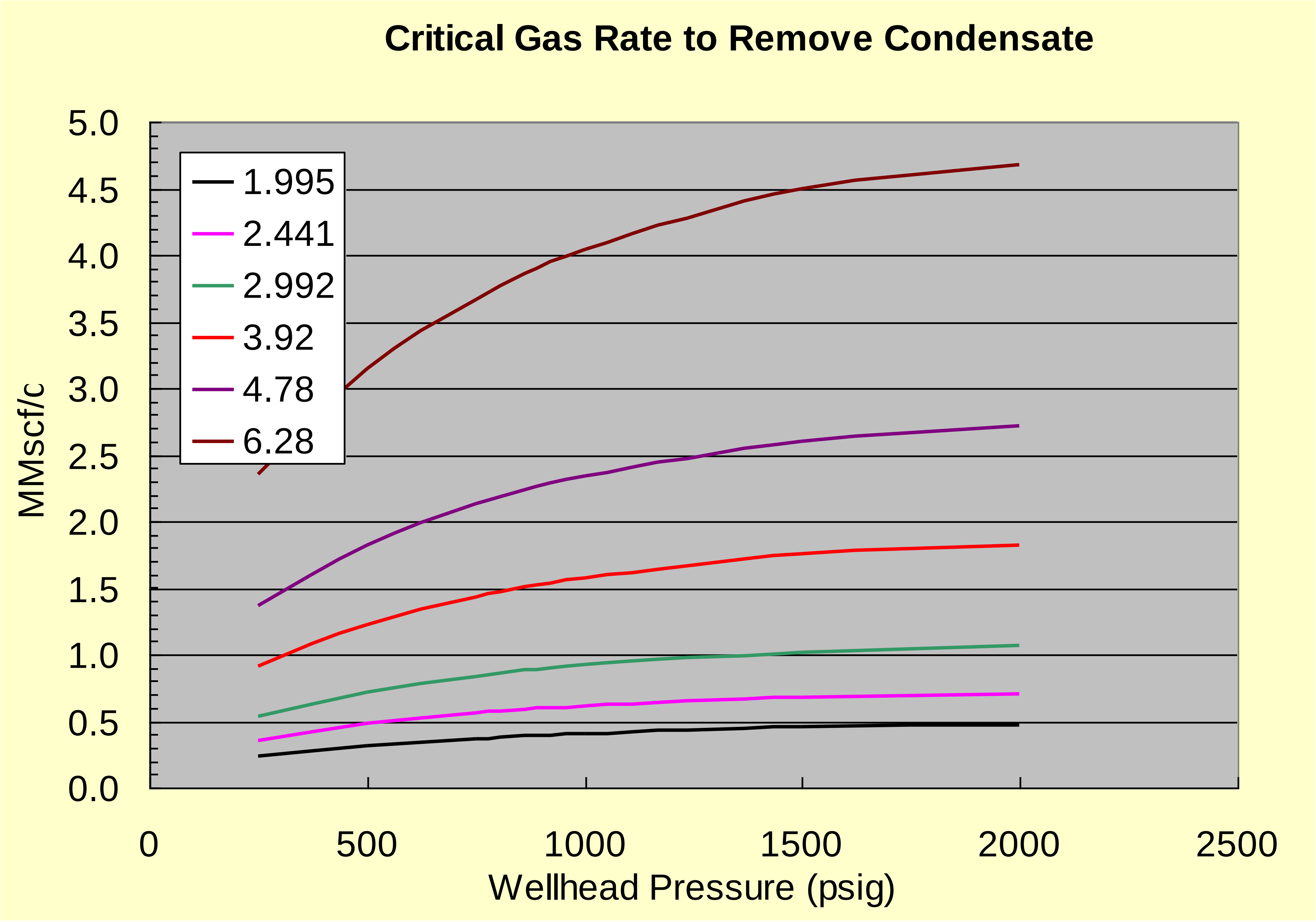


Critical Gas Rate to Remove Water
MMscf/d
1.995
2.441
2.992
3.92
4.78
6.28
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
0
100
200
300
400
500
600
Wellhead Pressure (psig)


Critical Gas Rate to Remove Water
1.995
2.441
2.992
3.92
4.78
6.28
10.0
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
MMscf/c
0
500
1000
1500
2000
2500
Wellhead Pressure (psig)

Critical Gas Rate to Remove Condensate




Critical Gas Rate to Remove Condensate
MMscf/c
Wellhead Pressure (psig)
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
0
500
1000
1500
2000
2500
1.995
2.441
2.992
3.92
4.78
6.28