اصول تکمیل چاه

خواص اساس سنگ و سیال مخزنی

سرفصل ها

آزمایشات چاه (Well Test)

روش های تکمیل چاه

آسیب سازند

اسید کاری

رسوب گذاری واکس و آسفالتن و تولید شن از چاه

آزمایش ساقه مته

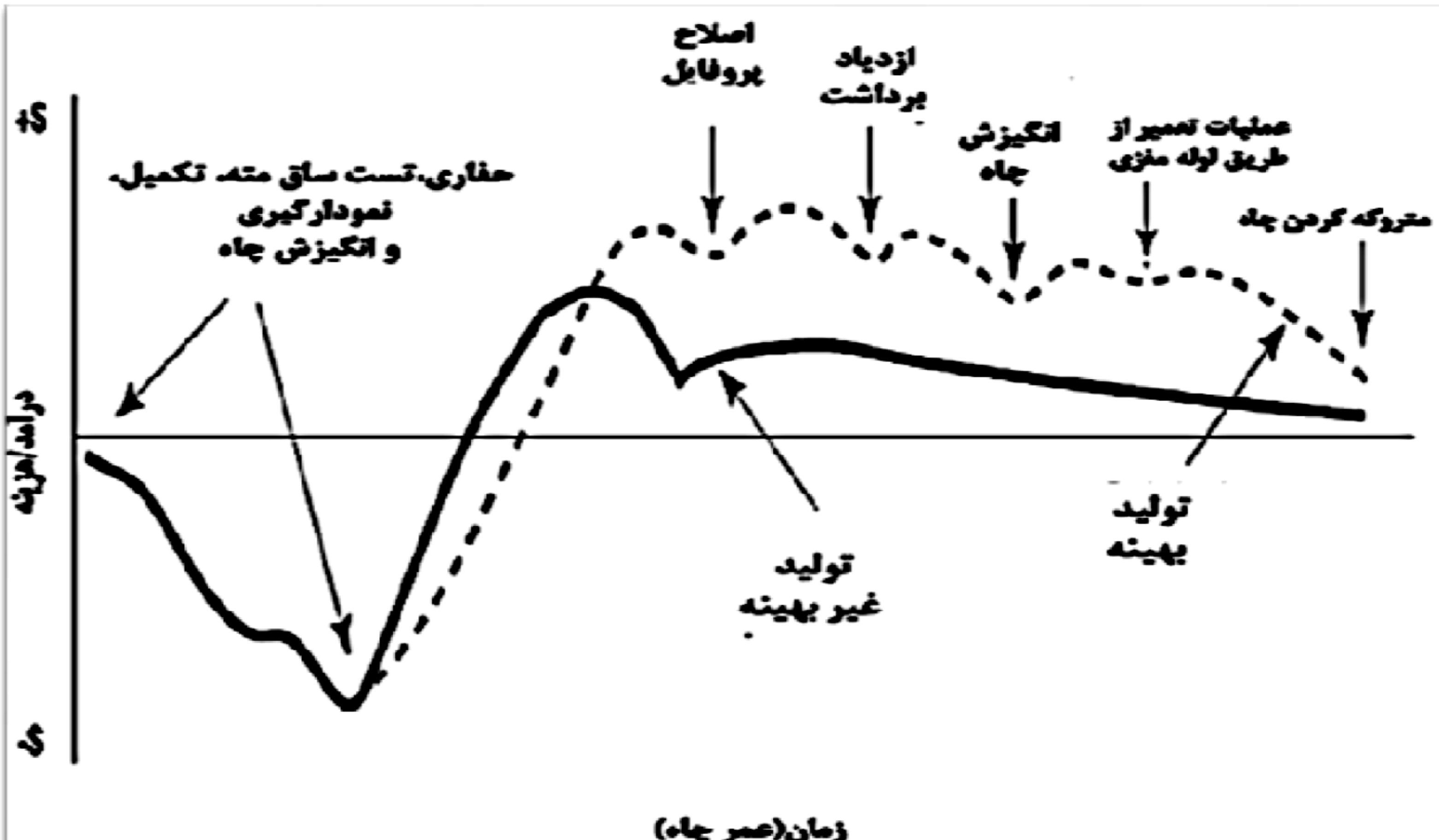
منابع

- Boyun Guo, William C. Lyons, Ali Ghalambor, “Petroleum Production Engineering”, 2007.

- Robert Earlougher, “Advances in Well Test Analysis”, 1977.

بررسی و عملیات تکمیل چاه

ضرورت برنامه ریزی جهت انجام عملیات تکمیل چاه



ساخت حفره چاه

- ساخت حفره چاه به منظور آماده‌سازی چاه جهت نصب تجهیزات درون‌چاهی و تکمیل نهایی انجام می شود.

- عملیات ضروری جهت ساخت حفره چاه:

۱- حفاری

عملیات مورد نیاز برای حفاری مناسب سازند و رسیدن به مخزن

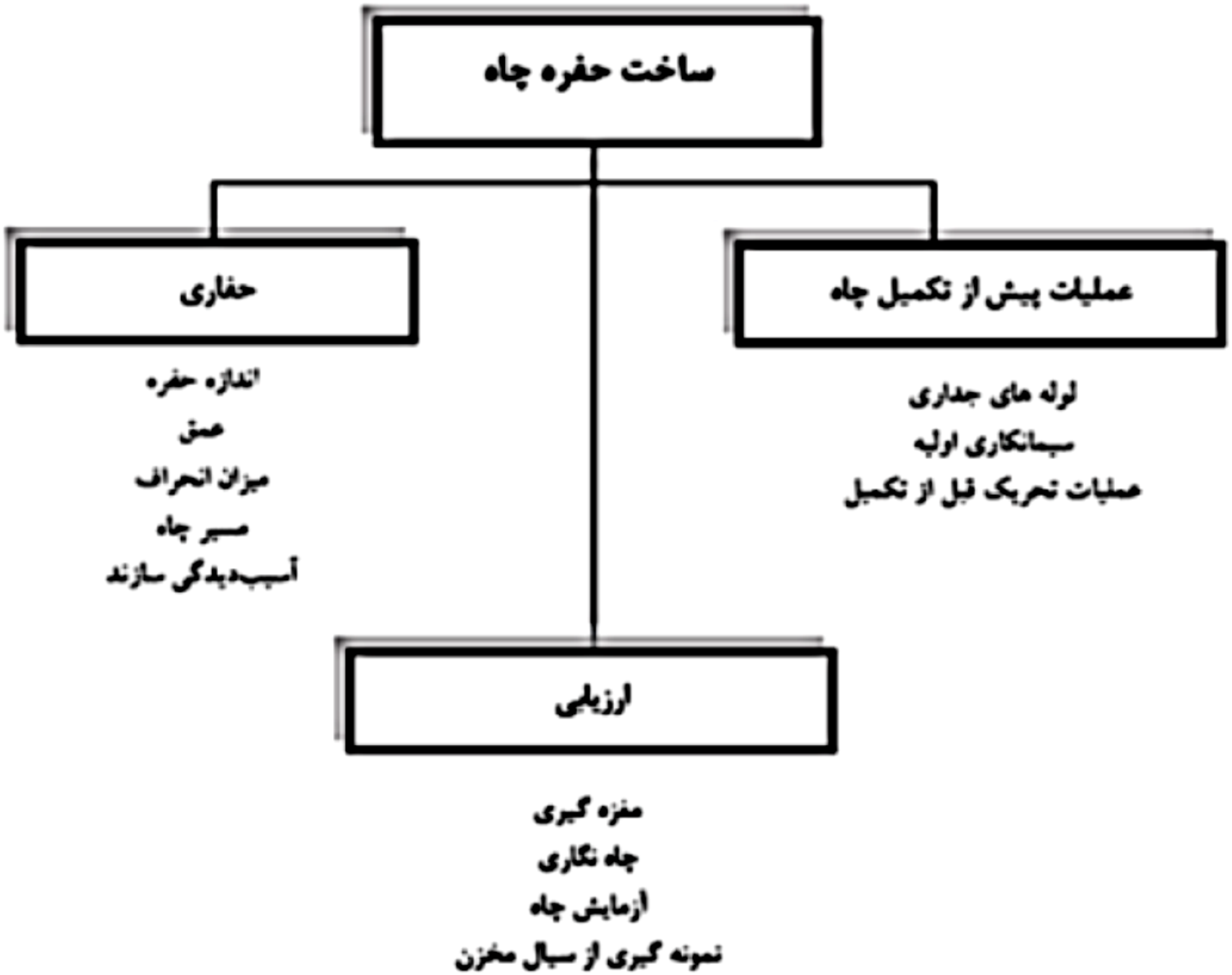
جلوگیری از ایجاد آسیب دیدگی

انتخاب ابعاد مناسب اجزاء تکمیلی

۲- عملیات تحریک پیش از تکمیل چاه

آماده-سازی نهایی حفره چاه در ناحیه مورد نظر جهت انجام عملیات نصب رشته تکمیل

مشخصات حفره چاه تاثیرگذار بر آرایش رشته تکمیل و انتخاب تجهیزات:



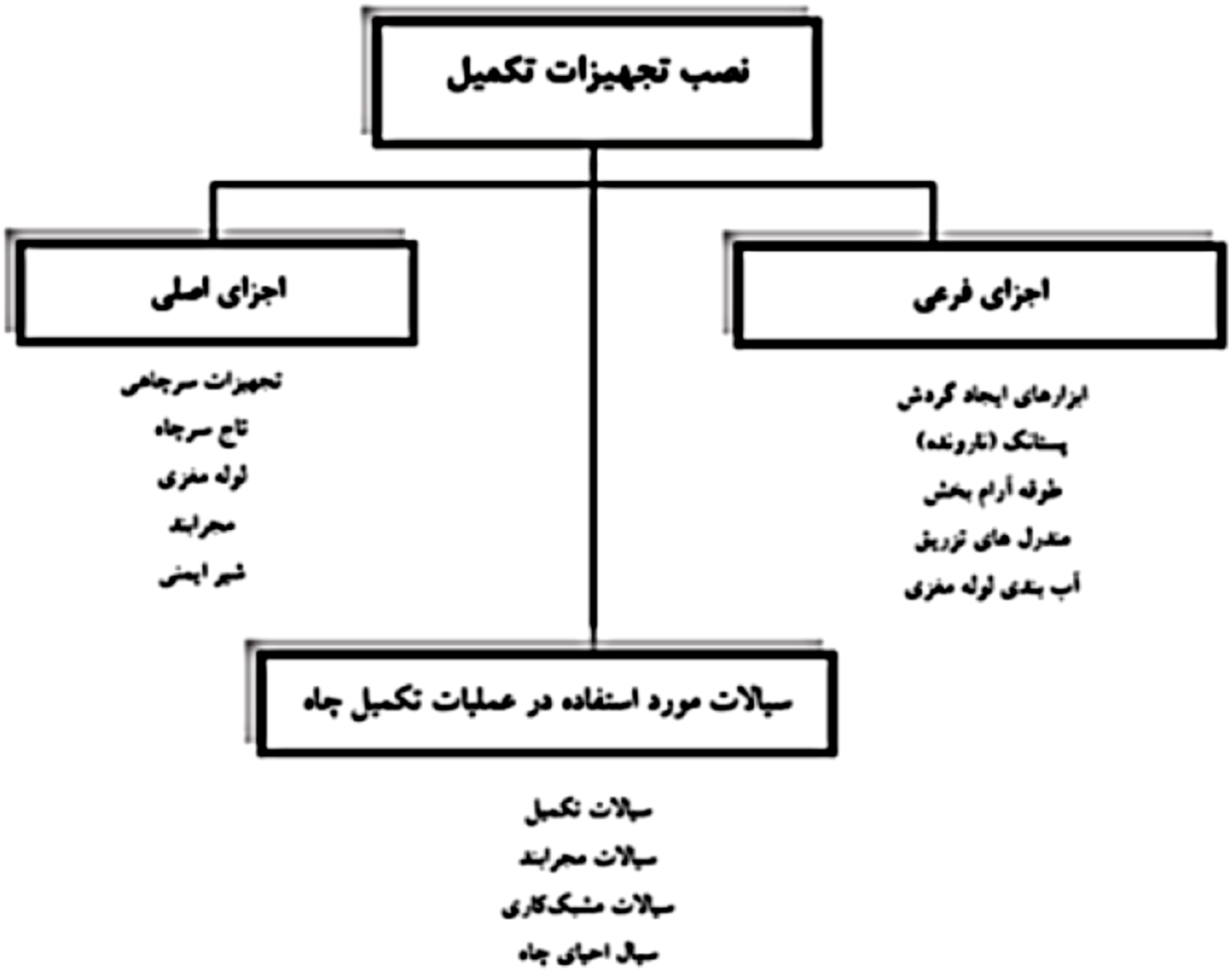
رشته تکمیل چاه

- دارای اهمیت بسیار به دلیل وابستگی عملکرد کلی سیستم به انتخاب صحیح و نصب مناسب تجهیزات است.

- ✓ نصب رشته تکمیلی=آغاز عملیات برنامه تکمیل

طبقه بندی تجهیزات تکمیل چاه به دو دسته کلی:

- اجزای اصلی
- اجزای فرعی



نصب تجهیزات تکمیل
اجزای فرعی
ابزارهای ایجاد گردش
پستانک (نازونده)
طوقه آرام بخش
مندرل های تزریق
آب بندی لوله مغزی
اجزای اصلی
تجهیزات سرچاهی
تاج سرچاه
لوله مغزی
مجرابند
شیر ایمنی
سیالات مورد استفاده در عملیات تکمیل چاه
سیالات تکمیل
سیالات مجرابند
سیالات مشبک‌کاری
سیال احیای چاه

آغاز فرآیند تولید

- مشبک-کاری جهت شروع جریان و ایجاد ارتباط بین مخزن و چاه بسیار مهم است.

- مشبک‌کاری به دو صورت زیر انجام می شود:

1. فروتعادلی

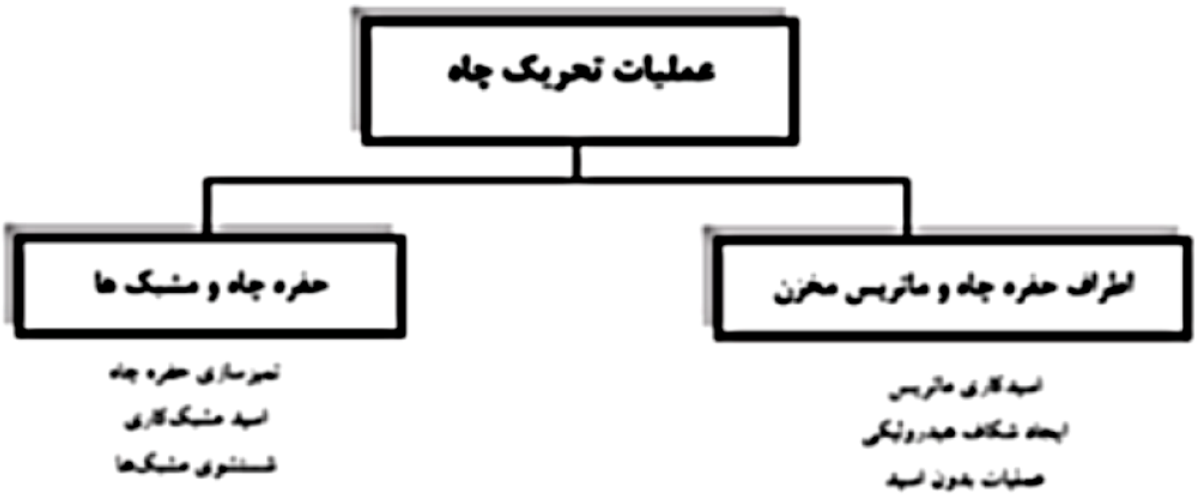
- فرآیند شروع جریان و تمیزسازی چاه باید بلافاصله پس از عملیات مشبک‌کاری انجام پذیرد.

2. فراتعادلی

- فرآیند شروع جریان از چاه و تمیزسازی چاه باید بصورت جداگانه انجام پذیرند.

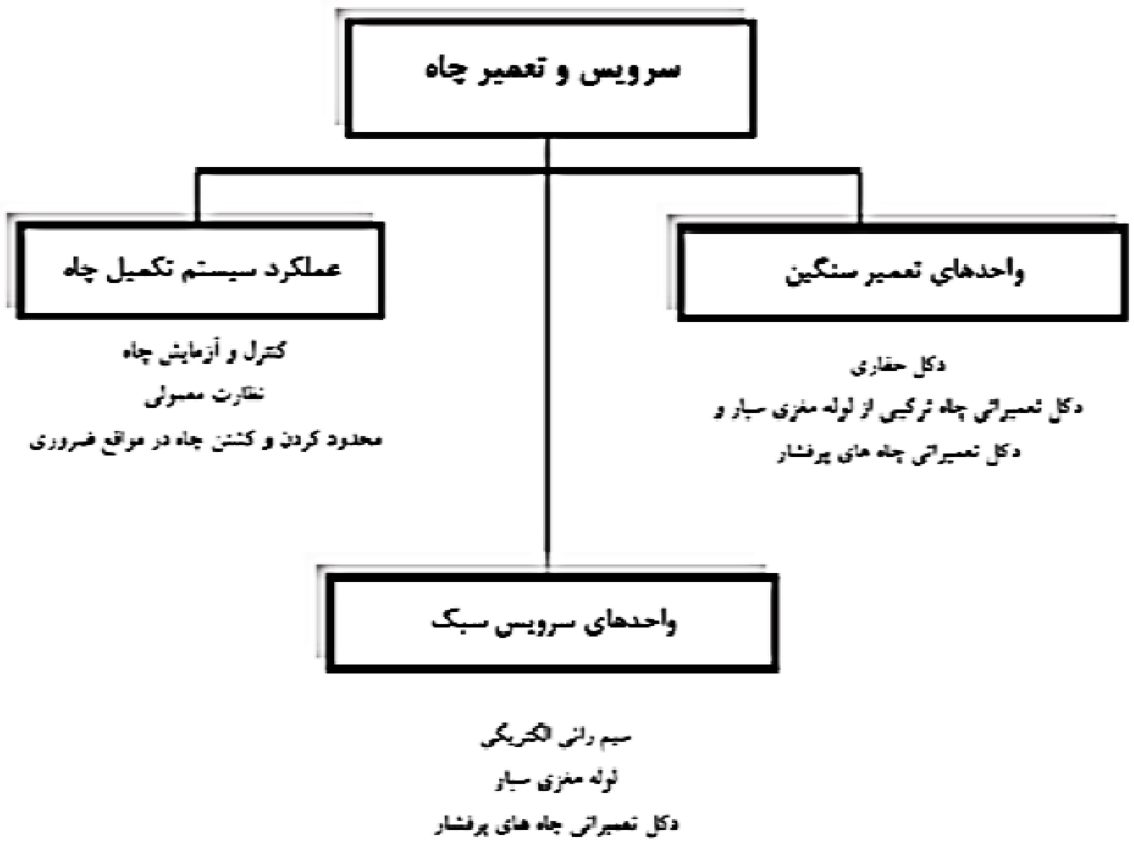
❑ چهار دسته عملیات تحریک:

- عملیات تمیزسازی چاه
- شستشوی مشبک‌ها یا کانال‌ها
- انجام عملیات بر روی ماتریس در ناحیه اطراف چاه
- ایجاد شکاف هیدرولیکی

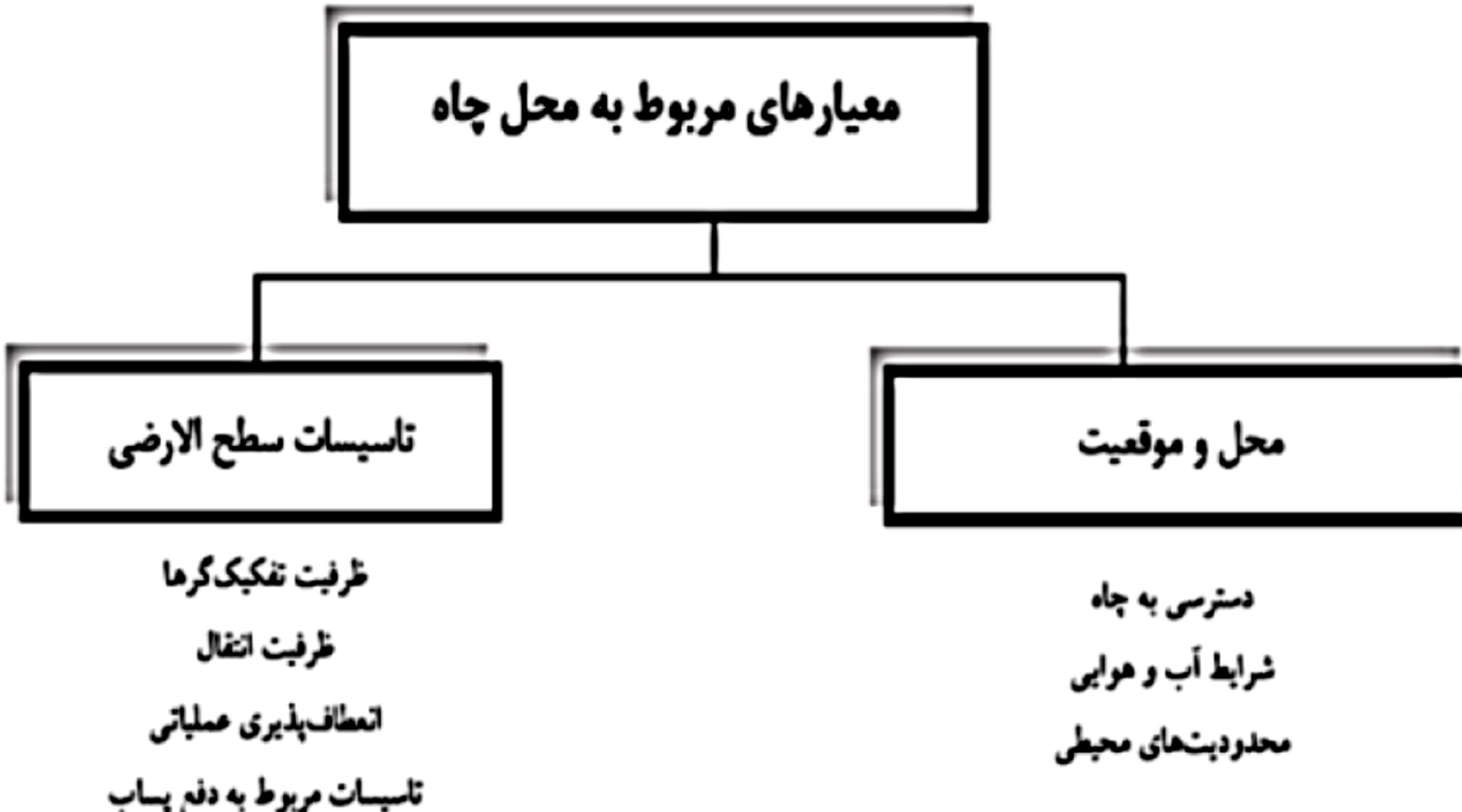


سرویس و تعمیر چاه

عملیات سرویس و تعمیر چاه



معیارهای مربوط به محل چاه



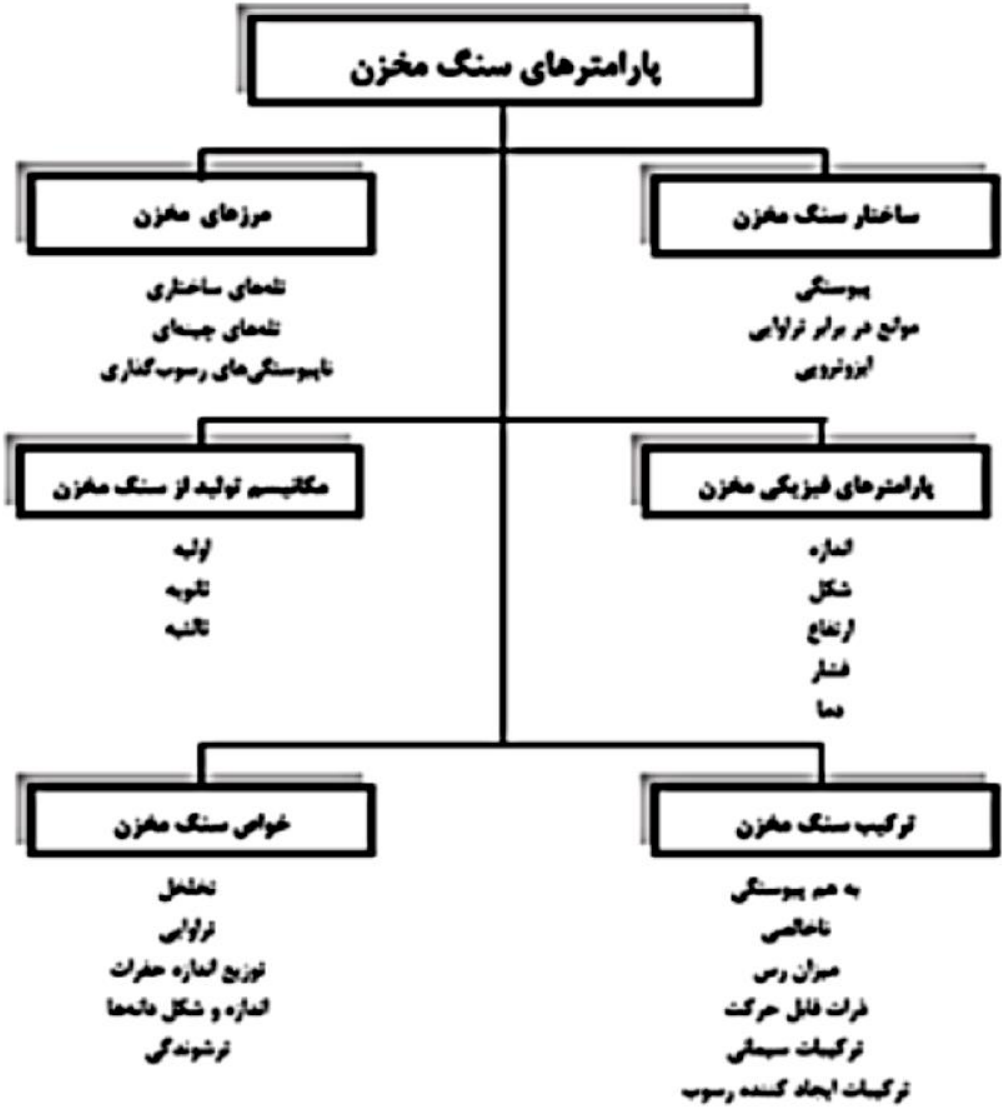
خصوصیات سنگ مخزن

- جمع آوری مشخصات سنگ مخزن از طریق برنامه‌های ارزیابی مخزن و نیز کسب اطلاعات از سازند مربوطه مانند عملیات مغزه‌گیری، نمودارهای چاه‌نگاری و همچنین چاه‌آزمایی

- موارد تاثیرگذار:

  - ✓ تعیین رفتار سنگ و سازند مربوطه و میزان واکنش‌پذیری آنها
  - ✓ ساختار سازند و میزان پایداری آن
  - ✓ دما و فشار مخزن

- پارامترهای سنگ مخزنی تاثیرگذار بر طراحی و انتخاب تجهیزات تکمیل



❑ مشخصات سیال مخزنی تاثیرگذار بر طراحی و انتخاب تجهیزات تکمیل

مشخصات سیال مخزنی

خواص شیمیایی

- ترکیب
- میزان واکس
- آسفالتین
- مواد ایجاد کننده خوردگی
- ترکیبات سمی
- رسوب

خواص فیزیکی

- دانسیته نفت
- گراویتی گاز
- ویسکوزیته
- نقطه ریزش
- نسبت گاز به نفت
- نسبت آب به نفت

- خواص سیالات مخزن، اساس طراحی و تحلیل سیستم های تولید نفت و گاز می باشد.
- تک فاز یا چند فاز بودن هیدروکربن در مخزن یا سطح به خواص آن بستگی دارد.
- نمودارهای فازی ، ابزارهای مناسبی برای تشخیص چندفازی بودن سیال در شرایط معین فشار و دما هستند.

خواص نفت

1. نسبت گاز به نفت (GOR)
2. دانسیته
3. ضریب حجمی سازند
4. ویسکوزیته
5. تراکم پذیری
6. کشش سطحی

نسبت گاز به نفت

- GOR عبارت است از مقدار گازی که (در شرایط استاندارد) در واحد حجم نفت در شرایط فشاری و دمایی مخزن حل خواهد شد.

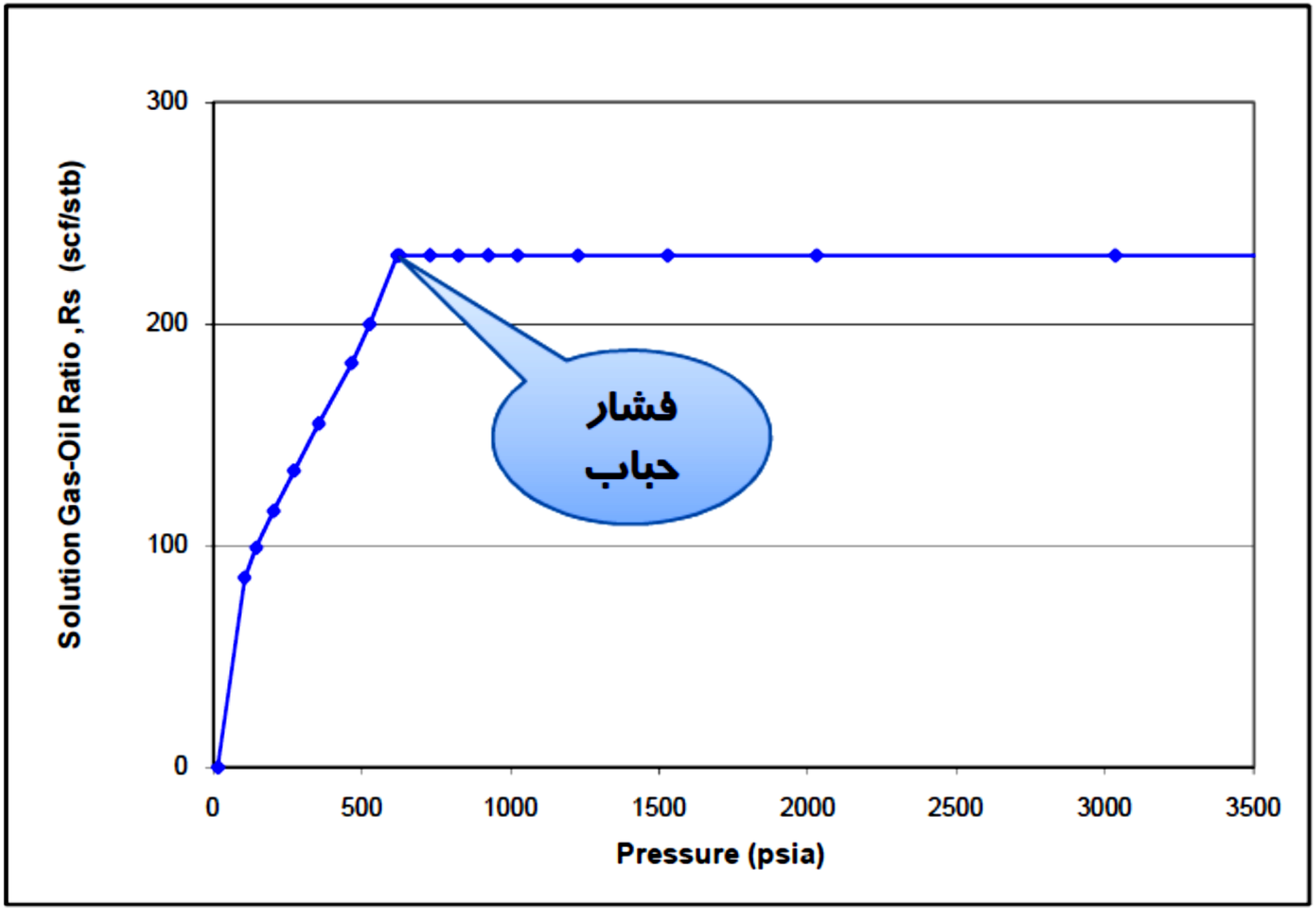
$$R_s = \frac{V_{gas}}{V_{oil}}$$

R_s : نسبت گاز به نفت محلول (scf/stb)

V_{gas} : حجم گاز در شرایط استاندارد (scf)

V_{oil} : حجم نفت در شرای تانک ذخیره (stb)

- ✓ شرایط استاندارد : فشار ۱٤.۷ پام و دمای ۶۰ درجه فارنهایت



تغییرات نسبت گاز به نفت برای یک مخزن نفتی در دمای ثابت (مخزن مسجدسلیمان)

- نسبت گاز به نفت را می توان در آزمایشگاه یا از طریق روابط تجربی بدست آورد:

$$R_s = \gamma_g \left[\frac{p}{18} \frac{10^{0.0125(°API)}}{10^{0.00091t}} \right]^{1.2048}$$

- در این رابطه دما بر حسب درجه فارنهایت است.

- با آزاد شدن گاز، مقدار R_s کاهش می یابد.

- در شرایط زیر گاز بیشتری آزاد می شود:

  - افزایش دما

  - کاهش فشار

- با کاهش فشار با کاهش فشار، گاز در دو حالت می تواند آزاد شود:

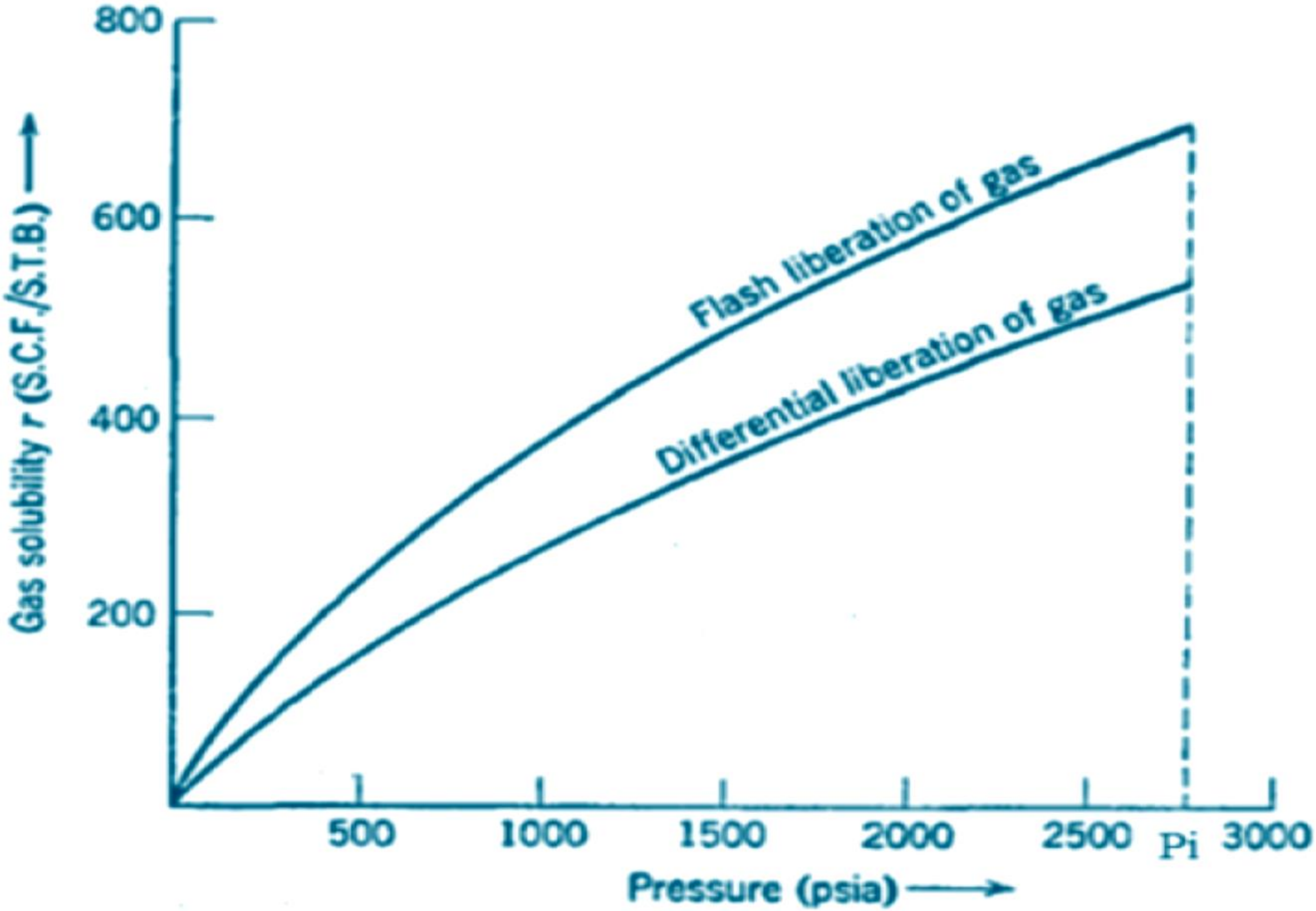
1. ناگهانی (Flash)
2. تفاضلی (Differential)

ناگهانی

- فشار به اندازه محدودی کاهش می یابد.
- شرایط تعادل حاصل می شود.
- در فشار ثابت ،آزادسازی گاز انجام می پذیرد

تفاضلی

- گاز آزاد شده بطور پیوسته از محفظه تماس با نفت خارج می شود.
- نفت با گاز آزاد شده در هر مرحله به تعادل می رسد (نه با کل گازهای مراحل قبل)
- چندین مرحله پشت سرهم Flash با افت فشار بسیار ناچیز در هر مرحله، شبیه حالت differentialخواهد بود.


800
600
400
200
Gas solubility r (S.C.F./S.T.B.)
Flash liberation of gas
Differential liberation of gas
500
1000
1500
2000
2500
Pi
3000
Pressure (psia)

- عوامل موثر بر حلالیت گاز در نفت :
  - فشار
  - دما
  - ترکیب گاز
  - ترکیب نفت

اثر فشار بر حلالیت گاز در نفت (در دمای ثابت)

- بر اساس قانون هنری رابطه مستقیم دارد.
- رفتار حلالیت با فشار خطی نیست.
- تا زمان رسیدن به فشار اشباع حلالیت با افزایش فشار افرایش می یابد.
- پس از فشار اشباع حلالیت مستقل از فشار می گردد.

- اثر دما برحلالیت گاز در نفت (در فشارثابت)
  - با کاهش دما افزایش می یابد.
- اثر ترکیب گاز بر حلالیت گاز در نفت
  - با افزایش ترکیبات فرار گاز کاهش می یابد.
  - در فشار و دمای ثابت و نفت خام معین، با کاهش وزن مخصوص گاز کاهش می یابد.

اثر ترکیب نفت خام بر حلالیت گاز در نفت

- با کاهش وزن مخصوص نفت افزایش می یابد.
- ترکیب نفت با وزن مخصوص پایین، شبیه گاز می باشد و گاز بیشتری در آن حل می شود.

دانسیته نفت

- دانسیته نفت عبارت است از مقدار جرم یک واحد حجم نفتی که در شرایط استاندارد با API بیان می شود و رابطه آن با دانسیته نفت به شکل زیر است:

$$^{\circ}API = \frac{141.5}{\gamma_o} - 131.5$$

- که وزن مخصوص نفت نیز عبارت است از:

$$\gamma_o = \frac{\rho_{o,st}}{\rho_w}$$

- دانسیته نفت را می توان با استفاده از روابط تجربی مختلف بدست آورد که یکی از این روابط، رابطه ارائه شده توسط احمد (۱۹۸۹) می باشد:

$$\rho_o = \frac{62.4\gamma_o + 0.0136 R_s \gamma_g}{0.972 + 0.000147\left[R_s\sqrt{\frac{\gamma_g}{\gamma_o}} + 1.25t\right]^{1.175}}$$

- ✓ در این رابطه دما (t) بر حسب درجه فارنهایت است.

ضریب حجمی سازند

- ضریب حجمی سازند عبارت است از مقدار حجم اشغال شده در مخزن (فشار و دمای حاکم) توسط یک بشکه نفت مخزن ذخیره و گاز قابل حل در آن.

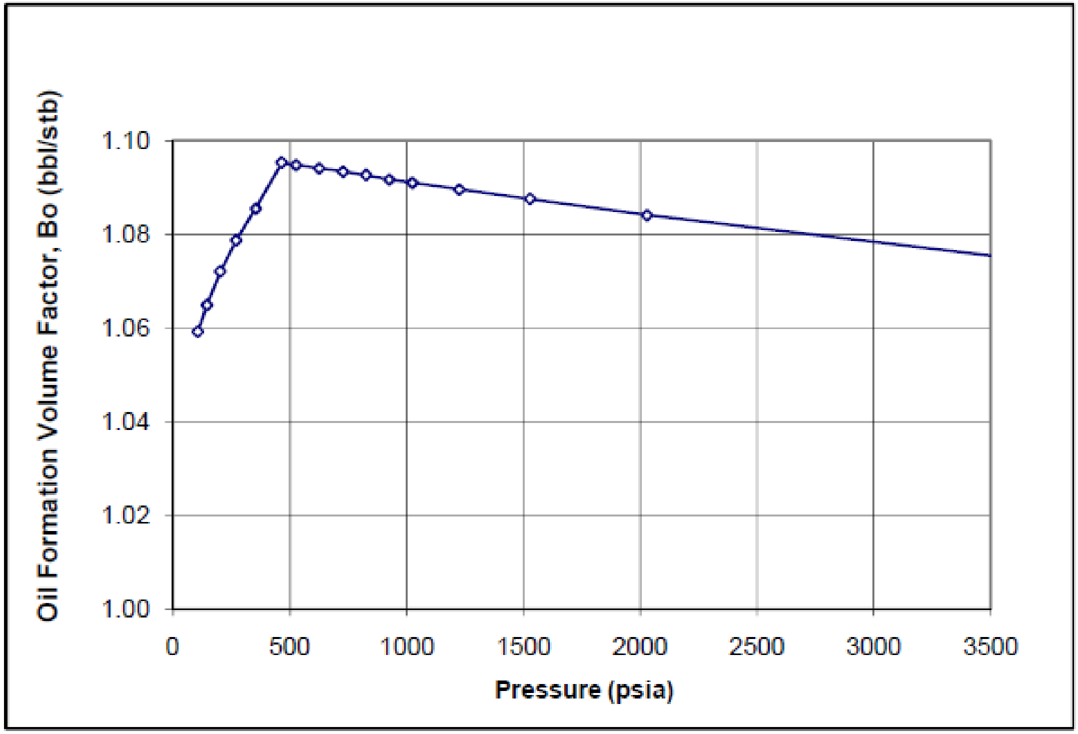
$$B_o = \frac{V_{res}}{V_{stb}} \qquad \left(\frac{bbl}{stb}\right)$$

- ضریب حجمی سازند را میتوان در آزمایشگاه یا از روابط تجربی بدست آورد.

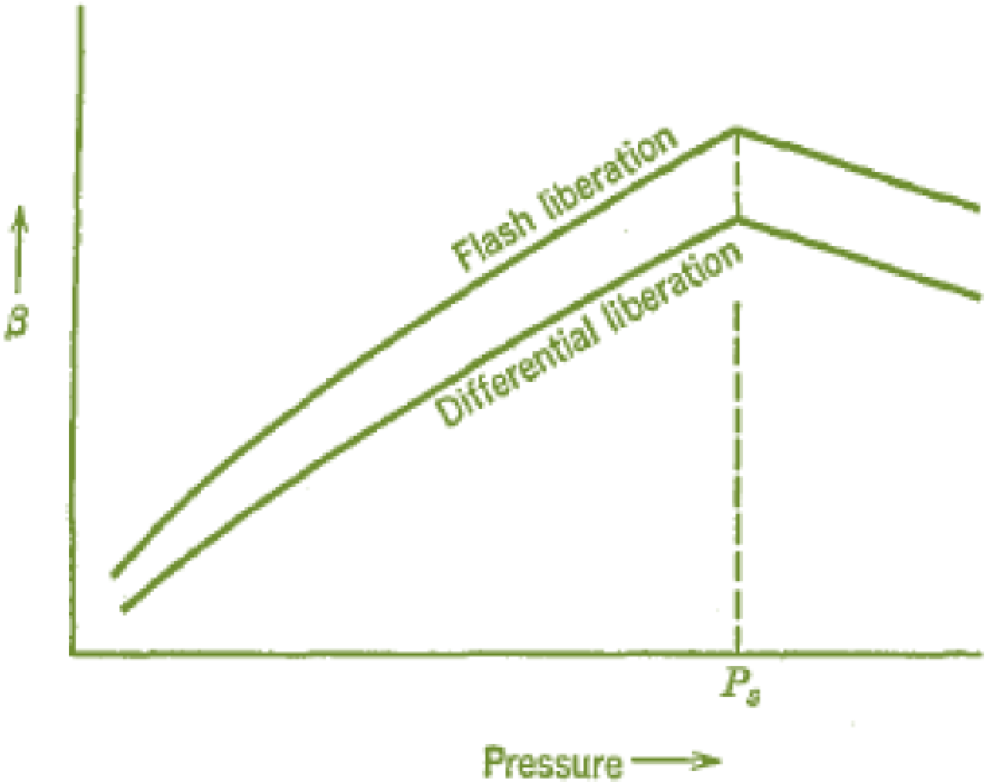
$$B_o = 0.9759 + 0.00012\left[R_s\sqrt{\frac{\gamma_g}{\gamma_o}} + 1.25t\right]^{1.2}$$

✓ که دما (t) بر حسب درجه فارنهایت است

❑ نمودار ضریب حجمی سازند برای یک مخزن نفتی (مسجدسلیمان) در شکل زیر نشان داده شده است:

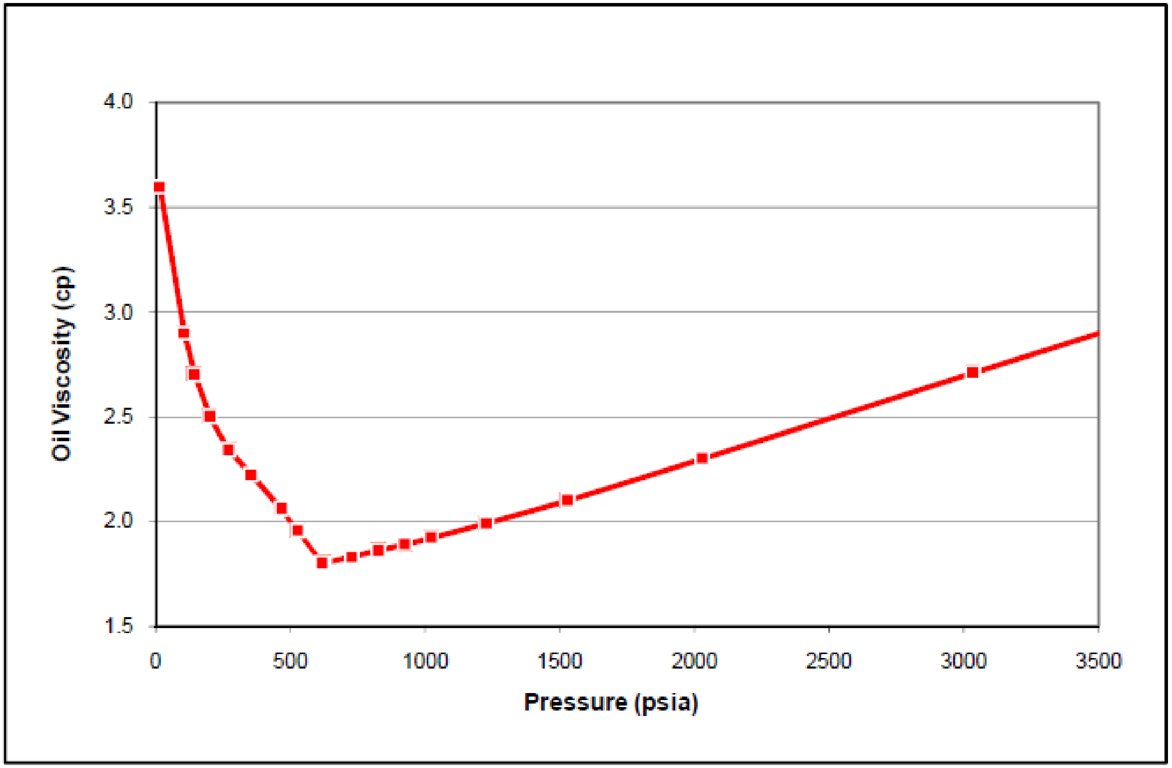


- لازم به ذکر است این ضریب بستگی به نوع آزادسازی گاز از نفت هنگام رسیدن به سطح است.



ویسکوزیته

- پارامتریست تجربی جهت توصیف مقاومت سیال در برابر جریان
- منحنی تغییرات ویسکوزیته برای مخزن نفتی مسجدسلیمان در شکل آورده شده است:



- اثر عوامل مختلف بر ویسکوزیته نفت:
  - ویسکوزیته نفت با کاهش دما افزایش می یابد.
  - ویسکوزیته نفت با افزایش فشار افزایش می یابد.
  - ویسکوزیته نفت با افزایش مقدار گاز محلول در نفت کاهش می یابد.

❑رابطه Standing (۱۹۸۱) که ویسکوزیته نفت مرده را می دهد از معروف ترین روابط می باشد:

$$\mu_{od} = \left(0.32 + \frac{1.8 \times 10^7}{API^{4.53}}\right)\left(\frac{360}{t + 200}\right)^A$$

❑ A:

$$A = 10^{\left(0.43 + \frac{8.33}{API}\right)}$$

❑برای نفت اشباع:

$$\mu_{ob} = 10^a \mu_{od}^b$$

که:

$$a = R_s(2.2 \times 10^{-7} R_s - 7.4 \times 10^{-4})$$

$$b = \frac{0.68}{10^c} + \frac{0.25}{10^d} + \frac{0.062}{10^e},$$

$$c = 8.62 \times 10^{-5} R_s,$$

$$d = 1.10 \times 10^{-3} R_s,$$

and

$$e = 3.74 \times 10^{-3} R_s,$$

و در نهایت برای نفت زیراشباع:

$$\mu_o = \mu_{ob} + 0.001(p - p_b)(0.024\mu_{ob}^{1.6} + 0.38\mu_{ob}^{0.56})$$

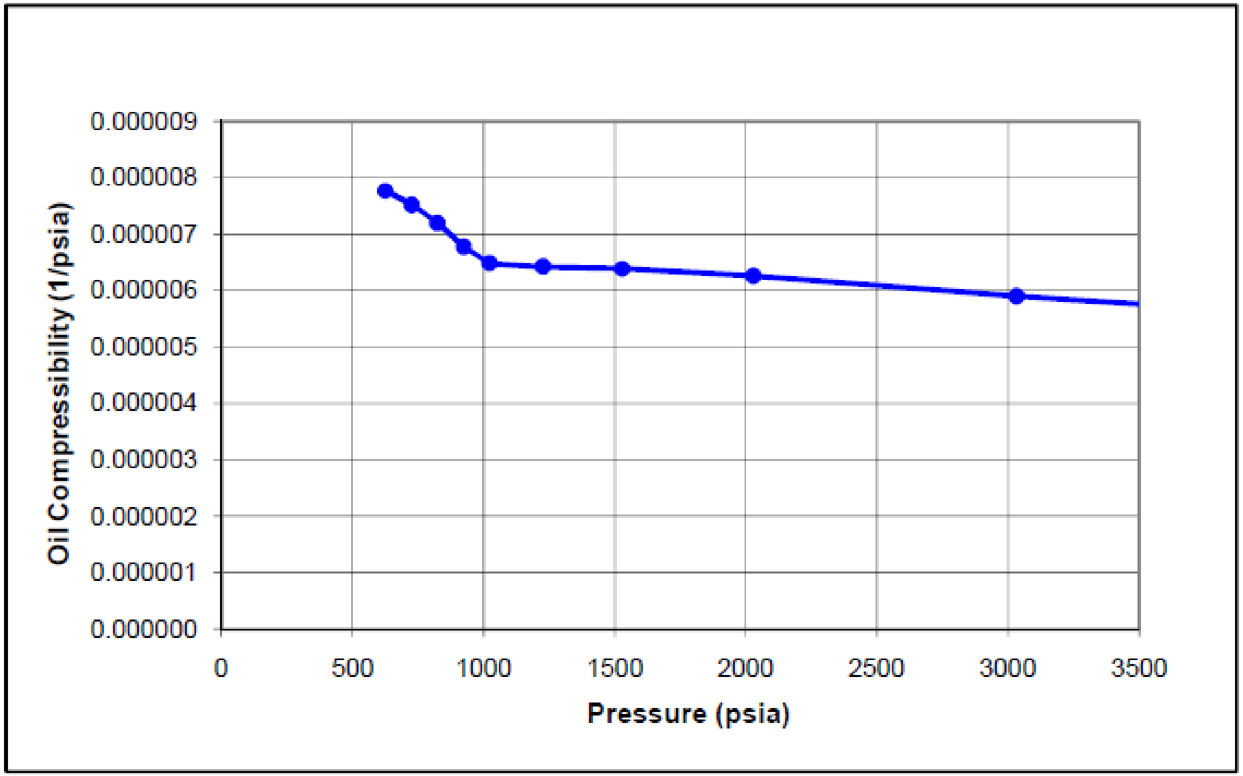
در روابط (Standing) دما بر حسب درجه فارنهایت در محاسبات لحاظ می شود

تراکم پذیری

- مقدار درصد تغییرات حجمی ناشی از تغییر فشار (در دمای ثابت)

$$C_o = -\frac{1}{V}\left(\frac{\partial V}{\partial P}\right)_T$$

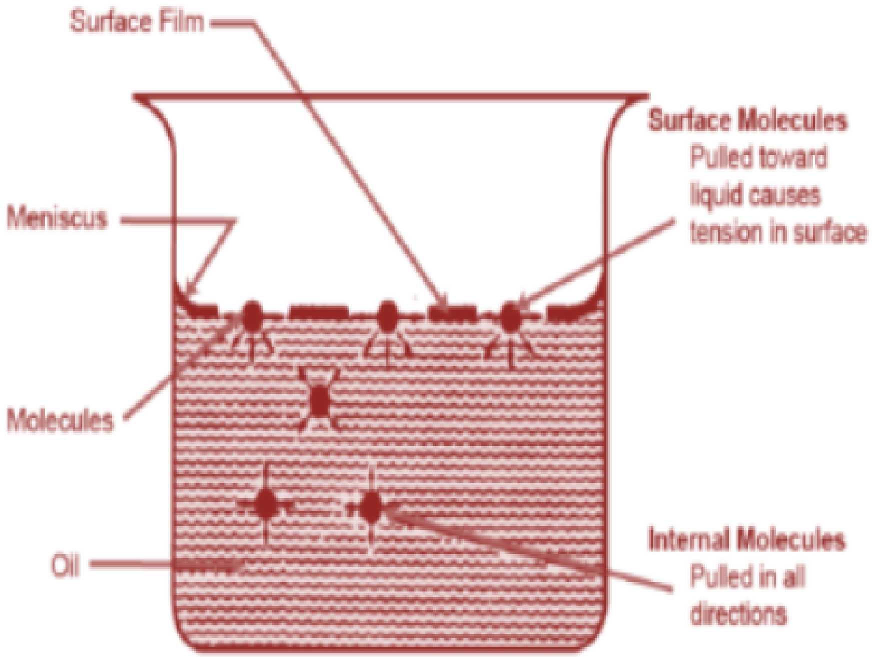
❑ شکل زیر تغییرات تراکم پذیری نفت را در فشار بالای حباب نشان برای مخزن مسجدسلیمان نشان می دهد:



کشش سطحی

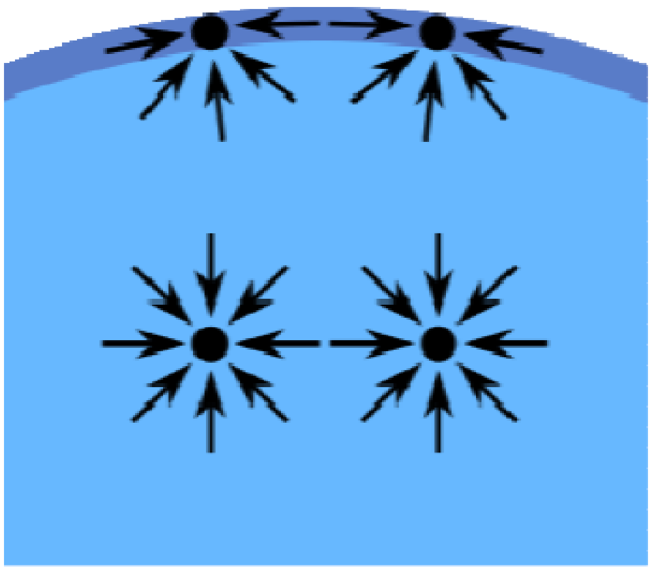
- کشش سطحی

  - نیرویی در سطح سیال است که سبب تمایل سیال به داشتن کمترین سطح می شود.
  - شکل قطره آب به دلیل وجود نیروهای کشش سطحی کره ای می باشد.
  - نیروی کشش سطحی کمتر، قطره کوچکتری خواهد داشت.
  - با IFT نشان داده می شود و از جنس نیرو بر واحد طول است.
  - در واحد dynes/sqcm است.



- جذب ماده خارجی در سطح آب، سبب کاهش نیروی کشش سطحی خواهد شد:
  - نیروی جاذبه بین مولکول های آب بدلیل پیوند هیدروژنی، قویتر از مولکول های دیگر است.

- نیروهای چسبندگی مولکول های مایع مسبب اصلی وجود کشش سطحی در سیال است.
- هر مولکول با نیروی برابر از طرف مولکول های مجاور کشیده می شود.
- جاذبه بین مولکول ها:
  - با توان دوم فاصله رابطه عکس دارد.
  - با جرم مولکول رابطه مستقیم دارد.



مثال : یک نمونه نفتی با حجم cc ۱۰۰۰(در شرایط مخزن) و دانسیته lb/cu ft ۵۱.۲۵ به شرایط استاندارد رسانده می شود. در این شرایط، حجم مایع cc ۶۸۵ و حجم گاز آزاد شده scf ۳.۰۲۵ می باشد .مطلوب است :

الف) وزن مخصوص و دانسیته API

ب) ضریب حجمی سازند

ج) نسبت گاز به نفت

حل:

الف) وزن مخصوص:

$$\gamma_o = \frac{\rho_o}{\rho_\omega} = \frac{51.25}{62.37} = 0.8217$$

دانسیته به API:

$$^\circ API = \frac{141.5}{\gamma_o} - 131.5 = \frac{141.5}{0.8217} - 131.5 = 40.7^\circ API$$

ب) ضریب سازند حجمی:

$$B_o = \frac{V_{res}}{V_{stb}} = \frac{1000\ res\ cc}{685\ ST\ cc} = 1.46\ \frac{res\ bbl}{STB}$$

ج) نسبت گاز به نفت:

$$R_s = \frac{V_{gas}}{V_{oil}} = \frac{3.025\ scf}{(685\ ST\ cc)(6.2898 \cdot 10^{-6}\ bbl\ /\ cc)} = 702\ \frac{scf}{STB}$$

خواص گاز طبیعی

1. وزن مخصوص گاز
2. فشار و دمای شبه بحرانی
3. ویسکوزیته
4. ضریب تراکم پذیری (ضریب انحراف)
5. دانسیته
6. ضریب حجمی سازند
7. تراکم پذیری

وزن مخصوص گاز

- عبارت است از نسبت وزن مولکولی ظاهری گاز به هوا

- وزن مولکولی هوا (با ۷۹٪ نیتروژن و ۲۱٪ اکسیژن) برابر ۲۸/۹۷ می باشد.

$$\gamma_g = \frac{MW_a}{28.97}$$

- که وزن مولکولی ظاهری گاز به ترکیب گاز بستگی دارد و از رابطه زیر بدست می آید:

$$MW_a = \sum_{i=1}^{Nc} y_i MW_i$$

فشار و دمای شبه بحرانی

- خواص بحرانی گاز هیدرو کربنی را نیز می توان به خواص اجزای تشکیل دهنده آن ربط داد:

$$P_{pc} = \sum_{i=1}^{Nc} y_i P_{ci}$$

$$T_{pc} = \sum_{i=1}^{Nc} y_i T_{ci}$$

- می توان از رابطه تجربی Sutton برای بدست آوردن خواص شبه بحرانی استفاده کرد:

$$P_{pc} = 756.8 - 131\gamma_g - 3.6\gamma_g^{\ 2}$$

$$T_{pc} = 169.2 - 349.5\gamma_g - 74\gamma_g^{\ 2}$$

ویسکوزیته گاز

- در مهندسی نفت، معمولا از ویسکوزیته دینامیکی استفاده می شود (که واحد آن cp است).
- رابطه آن با ویسکوزیته سینماتیکی به صورت زیر است:

$$\nu_g = \frac{\propto_g}{\rho_g}$$

- معمولا ترجیح داده می شود که ویسکوزیته گاز را به صورت مستقیم اندازه بگیرند اما در صورت مشخص بودن اجزا و ویسکوزیته آن ها می توان آن را از رابطه زیر بدست آورد:

$$\propto_g = \frac{\sum \propto_g y_i \sqrt{MW_i}}{\sum y_i \sqrt{MW_i}}$$

- غالبا ویسکوزیته گاز از چارت ها یا روابط منطبق بر این چارت ها بدست می آید که یکی از این رابطه ها، رابطه dempsey می باشد:

$$
\begin{aligned}
\mu_r &= \ln\left(\frac{\mu_g}{\mu_1} T_{pr}\right) \\
&= a_0 + a_1 p_{pr} + a_2 p_{pr}^2 + a_3 p_{pr}^3 + T_{pr}(a_4 + a_5 p_{pr} \\
&\quad + a_6 p_{pr}^2 + a_7 p_{pr}^3) + T_{pr}^2(a_8 + a_9 p_{pr} + a_{10} p_{pr}^2 \\
&\quad + a_{11} p_{pr}^3) + T_{pr}^3(a_{12} + a_{13} p_{pr} + a_{14} p_{pr}^2 \\
&\quad + a_{15} p_{pr}^3),
\end{aligned}
$$

- که مقادیر ضرایب عبارت است از:

$$\begin{aligned} a_0 &= -2.46211820 & a_8 &= -0.79338568 \\ a_1 &= 2.97054714 & a_9 &= 1.39643306 \\ a_2 &= -0.28626405 & a_{10} &= -0.14914493 \\ a_3 &= 0.00805420 & a_{11} &= 0.00441016 \\ a_4 &= 2.80860949 & a_{12} &= 0.08393872 \\ a_5 &= -3.49803305 & a_{13} &= -0.18640885 \\ a_6 &= 0.36037302 & a_{14} &= 0.02033679 \\ a_7 &= -0.01044324 & a_{15} &= -0.00060958 \end{aligned}$$

- در نهایت:

$$\mu_g = \frac{\mu_1}{T_{pr}} e^{\mu_r}$$

ضریب تراکم پذیری گاز

- مقدار انحراف رفتار گاز حقیقی نسبت به گاز ایده آل در فشار و دمای مشخص است:

$$Z = \frac{V_{actual}}{V_{ideal}}$$

- با داشتن فشار و دمای بحرانی کاهش یافته، میتوان Z را از چارت **Katz & Standing** بدست آورد:

$$P_{pr} = \frac{P}{P_{pc}} \qquad T_{pr} = \frac{T}{T_{pc}}$$

- چنانچه گاز، حاوی مقدار زیادی سولفید هیدروژن یا دی اکسیدکربن باشد مقدار Z خوانده شده از نمودار با Z واقعی متفاوت است.

- در این حال خواص شبه بحرانی بصورت زیر تصحیح می شود:

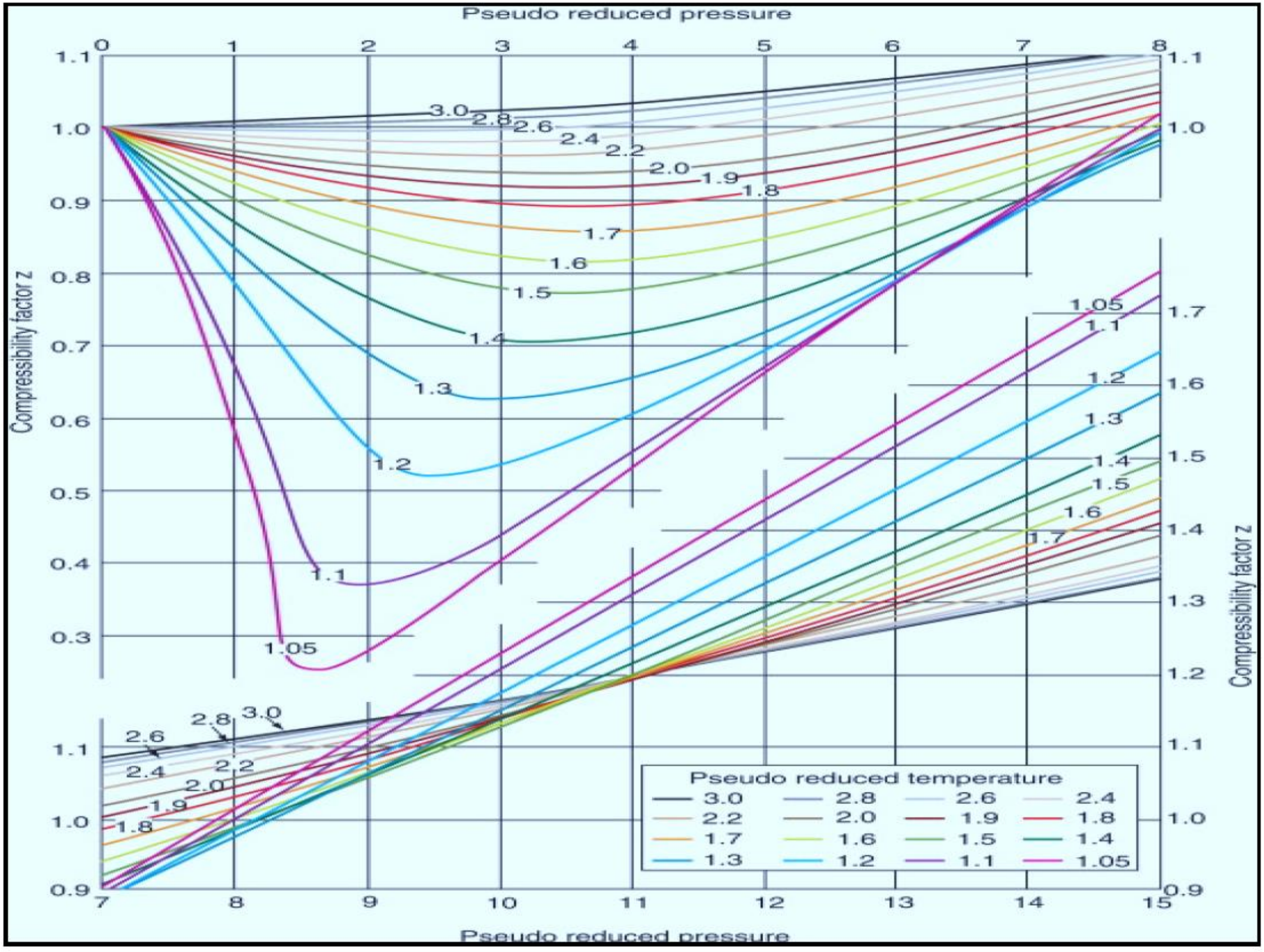
$$T_{pc'} = T_{pc} - \varepsilon_3$$

$$P_{pc'} = \frac{P_{pc} T_{pc'}}{T_{pc} + B(1-B)\varepsilon_3}$$

$$A = y_{H_2S} + y_{CO_2}$$

$$B = y_{H_2S}$$

$$\varepsilon_3 = 120(A^{0.9} - A^{1.6}) + 15(B^{0.5} - B^{4.0})$$


Pseudo reduced pressure
Compressibility factor z
Pseudo reduced temperature
3.0
2.8
2.6
2.4
2.2
2.0
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1.05
Pseudo reduced pressure

- اما در سال ۱۹۷٤، Beggs و Brill رابطه ای را جهت محاسبه Z ارایه کردند که دارای دقت نسبتا بالایی است:

$$z = A + \frac{1-A}{e^B} + Cp_{pr}^D$$

$$A = 1.39(T_{pr} - 0.92)^{0.5} - 0.36T_{pr} - 0.10,$$

$$B = (0.62 - 0.23T_{pr})p_{pr} + \left(\frac{0.066}{T_{pr} - 0.86} - 0.037\right)p_{pr}^2 + \frac{0.32\,p_{pr}^6}{10^E}$$

$$C = 0.132 - 0.32\log(T_{pr}),$$

$$D = 10^F,$$

$$E = 9(T_{pr} - 1),$$

$$F = 0.3106 - 0.49T_{pr} + 0.1824T_{pr}^2,$$

دانسیته گاز

- دانسیته گاز به فشار و دما بستگی دارد.

- با توجه به قانون گازهای حقیقی:

$$\rho_g = \frac{m}{V} = \frac{MW_a P}{ZRT}$$

- با در نظر گرفتن وزن مولکولی ۲۹ برای هوا و R=10.73 (Psia.ft^3/mole.^{o}R)

$$\rho_g = \frac{2.7\gamma_g P}{zT}$$

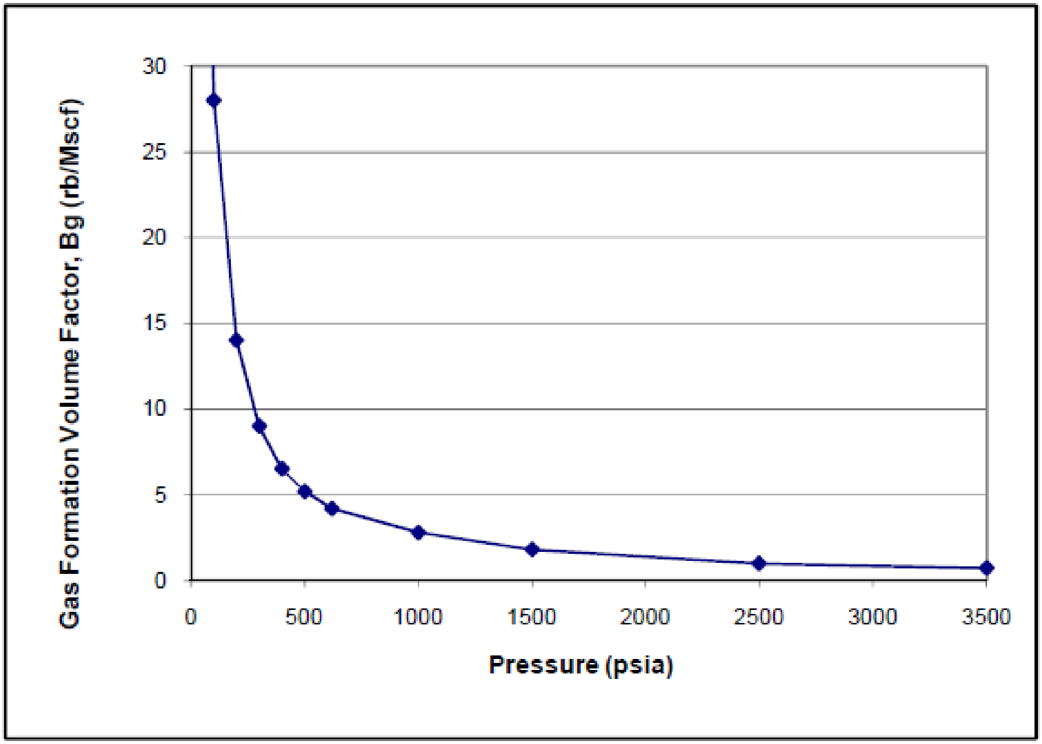
ضریب حجمی سازند گاز

- ضریب حجمی سازند گاز عبارت است از نسبت حجم گاز در شرایط مخزن به حجم آن در شرایط استاندارد:

$$B_g = \frac{V}{V_{sc}} = \frac{P_{sc}}{P}\frac{T}{T_{sc}}\frac{Z}{Z_{sc}} = 0.0283\frac{ZT}{P}$$

- که واحد آن، ft^3/scf می باشد.

❑ نمودار ضریب حجمی سازند، برای گاز موجود در میدان نفتی مسجد سلیمان در شکل زیر نشان داده شده است:



تراکم پذیری گاز

- تعریف آن دقیقا مانند تراکم پذیری نفت است و از رابطه زیر بدست می آید:

$$C_g = -\frac{1}{V}\frac{\partial V}{\partial P}$$

- از آنجا که برای گازها : $V = \frac{nZRT}{P}$؛ با جایگزینی در رابطه بالا داریم:

$$C_g = \frac{1}{P} - \frac{1}{Z}\frac{\partial Z}{\partial P}$$

مثال : نمونه ای از مایع مخزن با حجم ۴۰۰ سی سی در شرایط مخزن از درون جداکننده ای عبور می کند و در شرایط استاندارد وارد تانک ذخیره نفت می شود. حجم مایع در تانک ۲۷۴ سی سی است. در کل ۱/۲۱ استاندارد فوت مکعب گاز آزاد شده است.

الف) ضریب حجمی سازند نفت

ب) نسبت گاز به نفت محلول

را بدست آورید.

حل:

الف)ضریب حجمی سازند نفت

$$B_o = \frac{400rescc}{274stcc} = 1.46\,\frac{resbbl}{STB}$$

ب) نسبت گاز به نفت محلول

$$R_s = \frac{1.21scf}{(274stcc)(6.2898\cdot 10^{-6}bbl/cc)} = 702\,\frac{scf}{STB}$$

مثال : برای یک مخزن گازی با وزن مخصوص ۱۹.۲۸۵ و دمای ۲۱۳ درجه فارنهایت و فشار ۳۲۵۰ پام مطلوب است:

الف) وزن مخصوص

ب) ضریب انحراف گاز

ج) دانسیته گاز

د) ضریب حجمی سازند

حل:

الف) وزن مخصوص:

$$\gamma_g = \frac{MW_a}{28.97} = \frac{19.285}{29} = 0.665$$

ب) ضریب انحراف گاز:

ابتدا خواص شبه بحرانی را محاسبه می کنیم:

$$P_{pc} = 756.8 - 131\gamma_g - 3.6\gamma_g^{\ 2} = 756.8 - 131\cdot\ 0.665 - 3.6\cdot\ 0.665^2 = 668\ psia$$

$$T_{pc} = 169.2 - 349.5\gamma_g - 74\gamma_g^{\ 2} = 169.2 - 349.5\cdot\ 0.665 - 74\cdot\ 0.665^2 = 369\,°R$$

پس:

$$P_{pr}=\frac{P}{P_{pc}}=\frac{3250}{668}=4.87 \qquad T_{pr}=\frac{T}{T_{pc}}=\frac{460+213}{369}=1.82$$

از چارت Standing-Katz داریم : Z=0.918

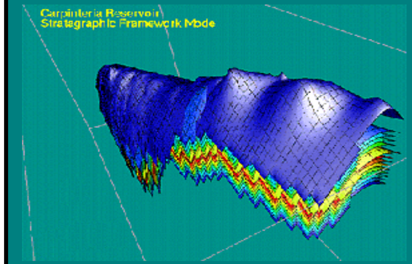
ج) دانسیته گاز:

$$\rho_g=\frac{2.7\gamma_g P}{zT}=\frac{2.7\cdot\ 0.665\cdot\ 3250}{0.918\cdot\ (213+460)}=9.45\,\frac{lb_m}{ft^3}$$

د) ضریب حجمی سازند

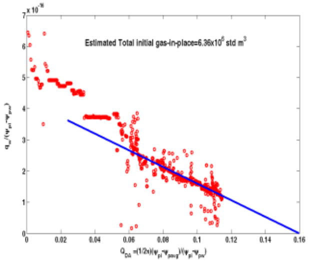
$$B_g = 0.0283\frac{ZT}{P} = 0.0283 \cdot \frac{0.918 \cdot (460+213)}{3250} = 5.38 \cdot 10^{-3}\ ft^3 / scf$$

Importance of Well Data Analysis



Reservoir Information

Predictive Models (forward solution)

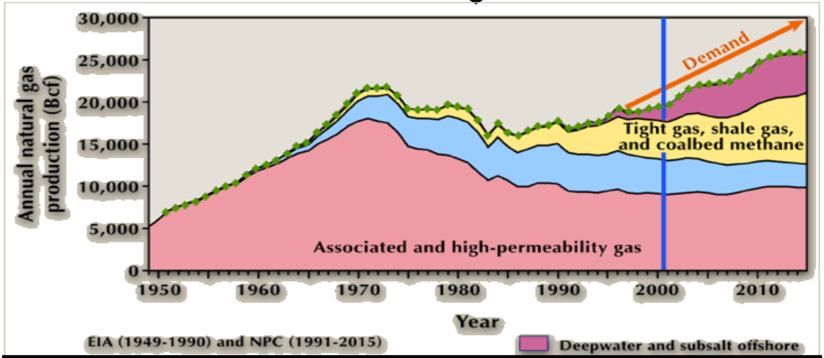


Production Analysis Models (backward solution)

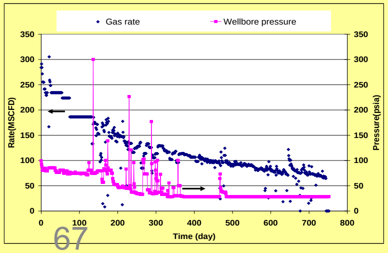
(i) Well test models

Material balance models

(iii) Decline curve analysis



Production Forecast



Field Data

(i) Well test data

(ii) Production data

Economic Study and Decision Making for the Field Development

Well

A communication tool:

- The reservoir can be evaluated by the well testing
- The reservoir is monitored through the well

A production tool:

- The reservoir production capacity depends on the well/ reservoir communication quality

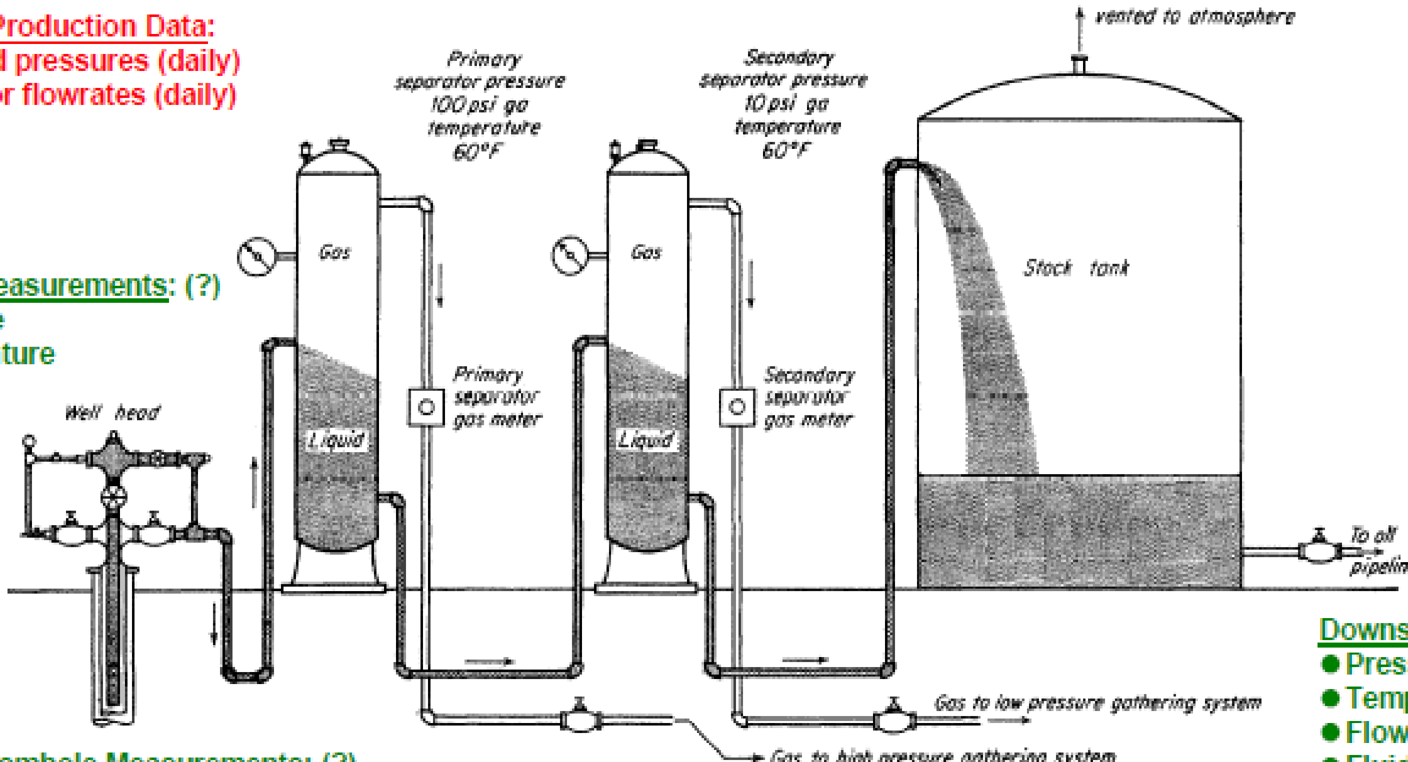
Production System

<u>Common Pressure Transient Test Data</u>:
- Bottomhole pressures (high frequency/high resolution)
- Separator flowrates (on the hour or day (at best))

<u>Common Production Data</u>:
- Wellhead pressures (daily)
- Separator flowrates (daily)

<u>Surface Measurements</u>: (?)
- Pressure
- Temperature

Manual Rate Control



<u>Downstream</u>: (?)
- Pressure
- Temperature
- Flowrate
- Fluid sampling

<u>Bottomhole Measurements</u>: (?)
- Pressure
- Temperature

The Objectives of Well Test
(1) Reservoir Evaluation

To reach a decision as to how best to produce a given reservoir we need to know its deliverability, properties and size.

- **Deliverability (conductivity; kh)**
  - Design of well spacing
  - Number of wells
  - Wellbore stimulation
- **Properties (initial reservoir pressure)**
  - Potential energy of the reservoir
- **Size (reservoir limits)**
  - Closed or open (with aquifer support) reservoir boundaries
- Near well conditions (skin, storage and turbulence)

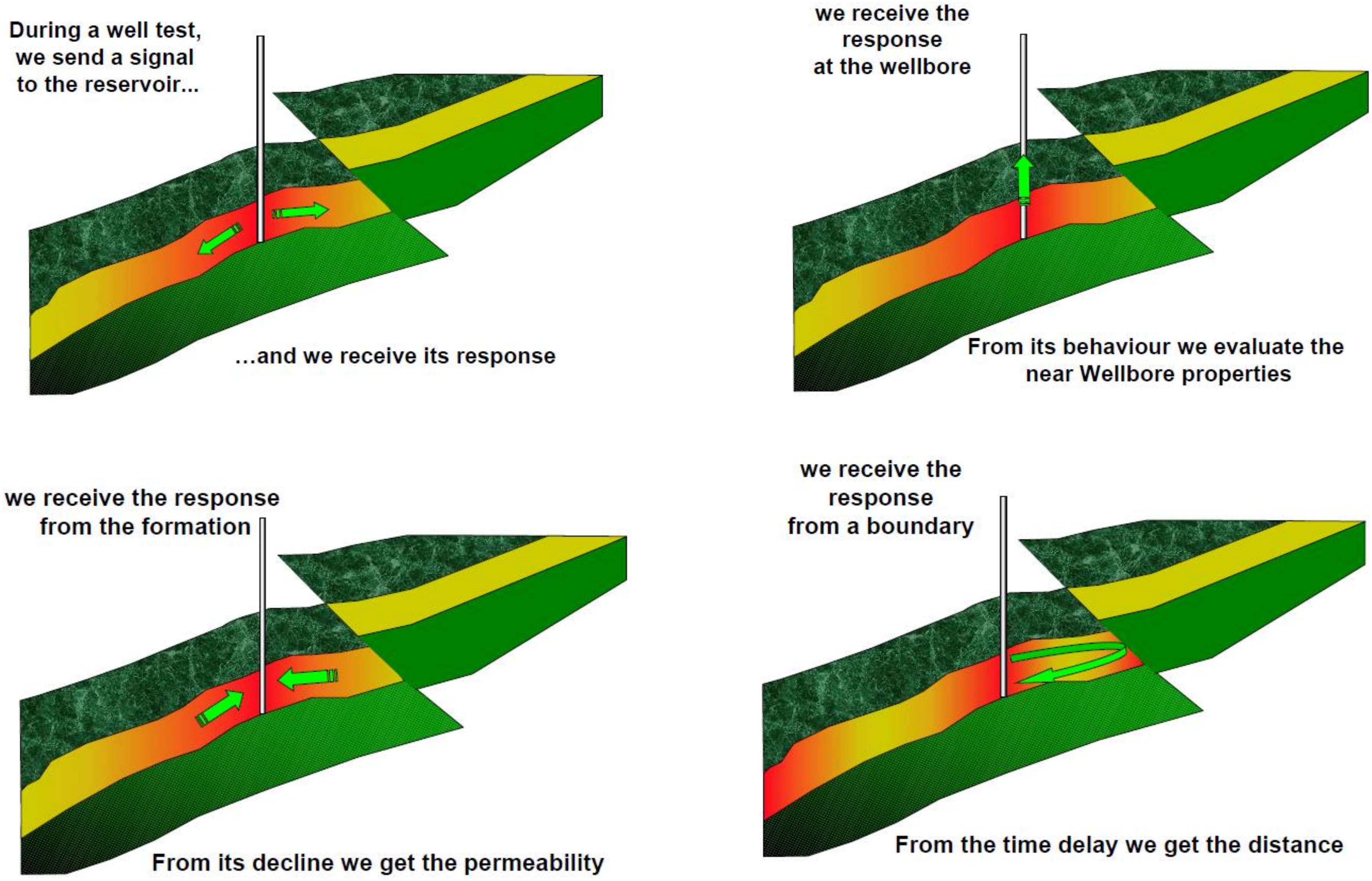
The Objectives of Well Test (2) Reservoir Management

- Reservoir management
  - Monitoring performance and well conditions

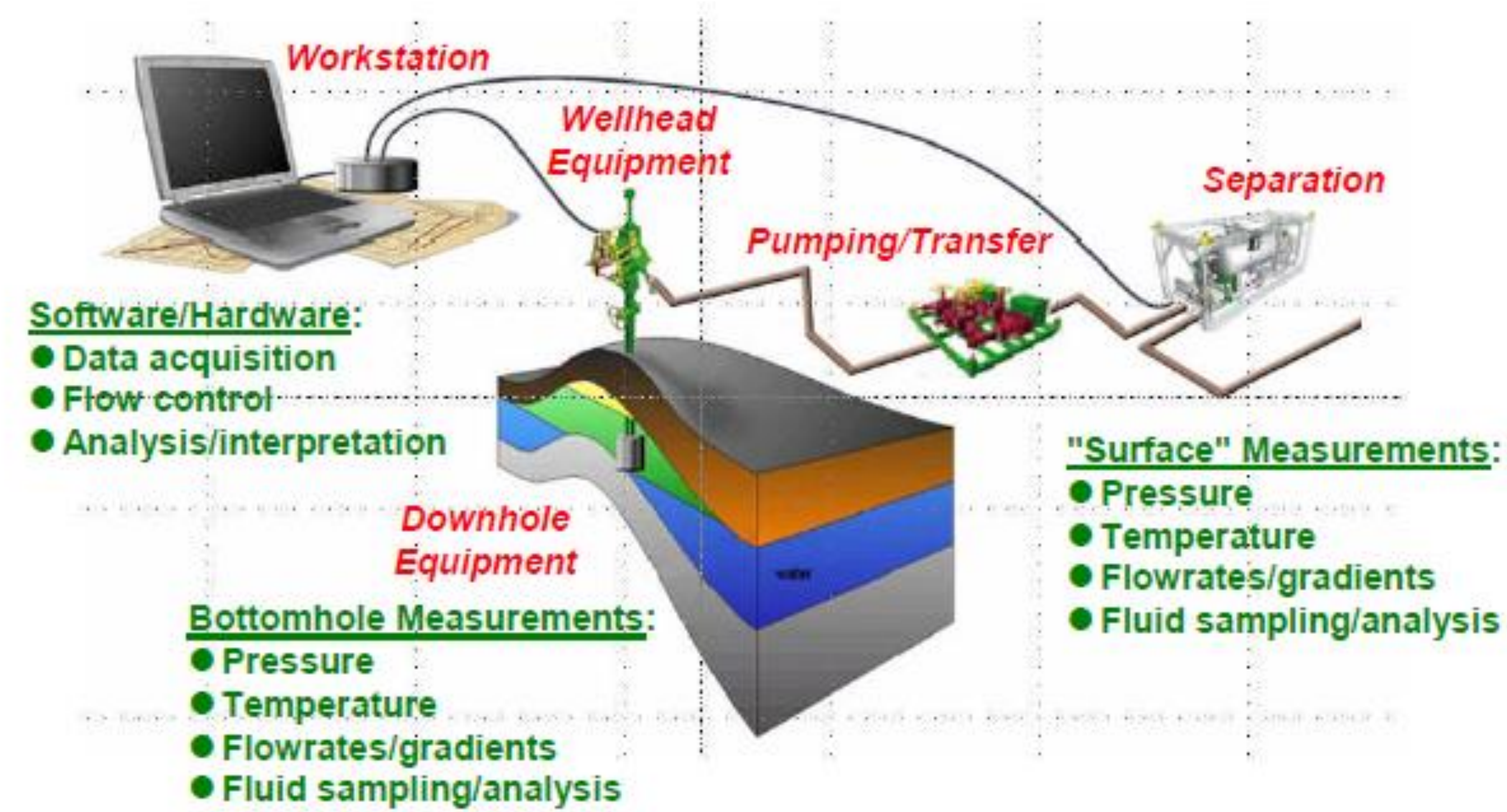
The Objectives of Well Test (3) Reservoir Description

- Reservoir description
  - Fault, Barriers
  - Estimation of bulk reservoir properties

The Well Test Concept



Standard Well Test Set-up



Formation Evaluation

	APPROXIMATE DEPTH OF INVESTIGATION
1. CORING	10 cm
2. LOGGING	50 cm
3. DST / RFT	1 - 10 metres
4. WELL TESTING	50 - 500 metres
5. PRODUCTION	whole reservoir

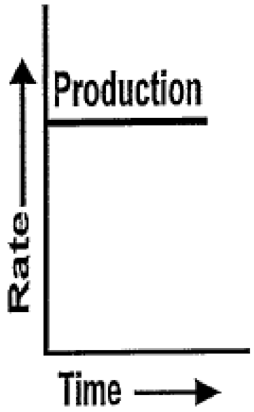
Types of Test

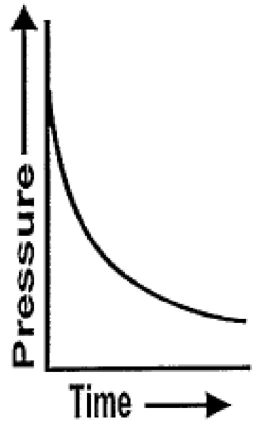
Type of tests is governed by the test objective.

- Transient tests which are relatively short term tests are used to define reservoir characteristics.
  - Drawdown Test
  - Buildup Test
  - Injection Test
  - Falloff Test
  - Interference Test
  - Drill Stem Test
- Stabilized tests which are relatively long duration tests are used to define long term production performance.
  - Reservoir limit test
  - AOF (single point and multi point)
  - IPR (Inflow Performance Relationship)

Types of Test-Drawdown Test

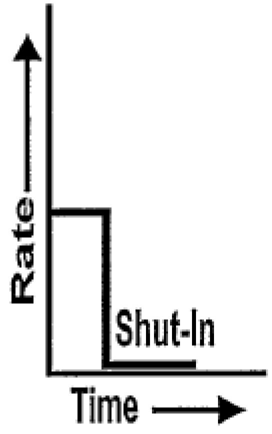
- **Conditions**
  - An static, stable and shut-in is opened to flow .
  - flow rate is supposed to be constant (for using traditional analysis).
- **Objective**
  - To obtain average permeability of the reservoir rock within the drainage area of the well
  - To assess the degree of damage or stimulation
  - To obtain pore volume of the reservoir
  - To detect reservoir inhomoginiety within the drainage area of the well.

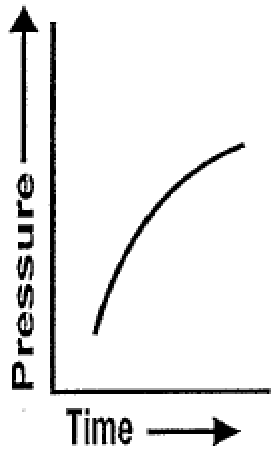




Types of Test-Buildup Test

- **Conditions**
  - A well which is already flowing (ideally constant rate) is shut-in
  - Downhole pressure measured as the pressure builds up
- **Objective**
  - To obtain average permeability of the reservoir rock within the drainage area of the well
  - To assess the degree of damage or stimulation
  - To obtain initial reservoir pressure during the transient state
  - To obtain the average reservoir pressure over the drainage area of the well during pseudo-steady state

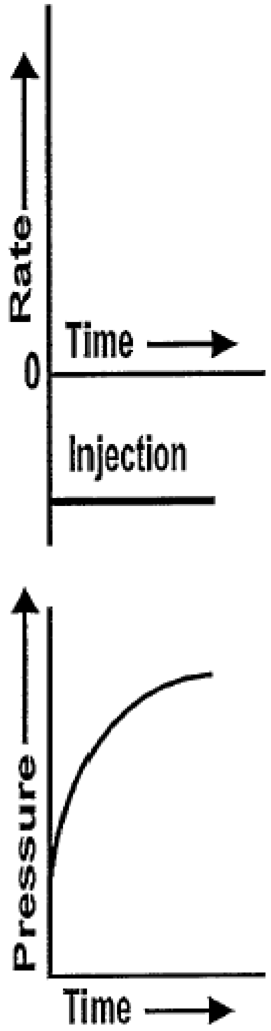




Types of Test-Injection Test

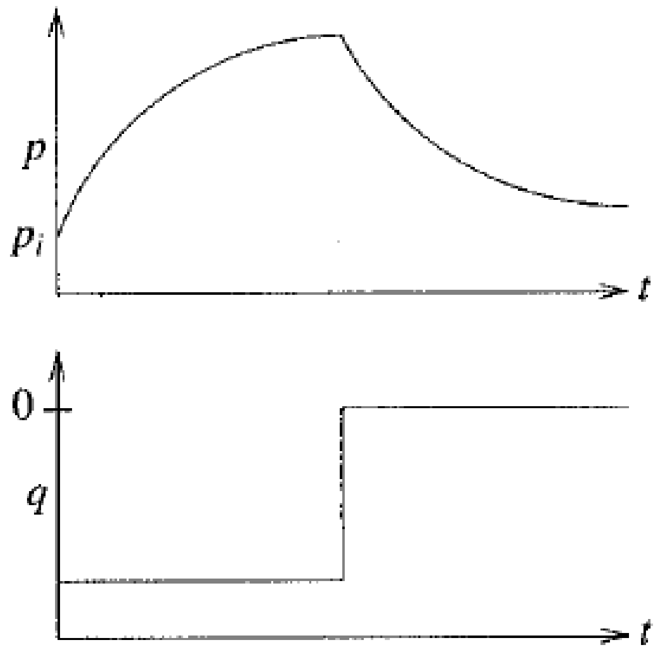
- **Conditions**
  - An injection test is conceptually identical to a drawdown test, except flow is into the well rather than out of it.

- **Objective**
  - Injection well testing has its application in water flooding, pressure maintenance by water or gas injection, gas recycling and EOR operations.
  - In most cases the objective of the injection test is the same as those of production test (k,S,Pavg).
  - Determination of reservoir heterogeneity and front tracing.



Types of Test-Fall off Test

A pressure falloff test is usually proceeded by an injectivity test of a long duration. Injection then is stopped while recording the pressure. Thus, the pressure falloff test is similar to the pressure buildup test.



As with injection test, falloff test, interpretation is more difficult if the injected fluid is different from the original reservoir fluid.

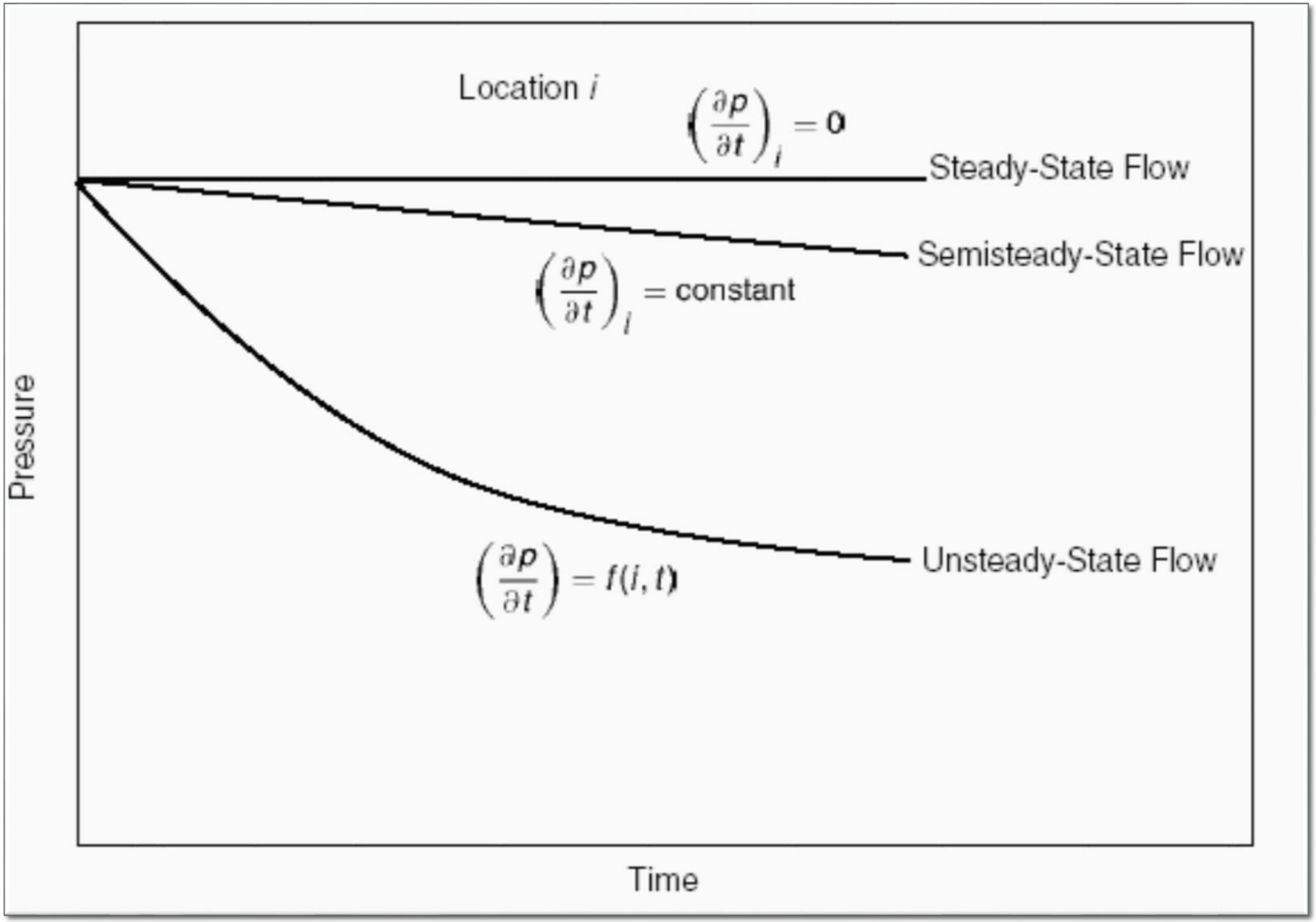
Types of Test

- **Interference Test:**
  - In an interference test one well is produced and pressure is observed in a different wells.
  - To test reservoir continuity
  - To detect directional permeability and other major reservoir heterogeneity
  - Determination of reservoir volume
- **Drill Stem Test (DST):**
  - It is a test commonly used to test a newly drilled well (since it can only be carried out while a rig is over the hole.
  - In a DST, the well is opened to flow by a valve at the base of the test tool, and reservoir fluid flows up the drill string.
  - Analysis of the DST requires the special techniques, since the flow rate is not constant as the fluid rises in the drill string.

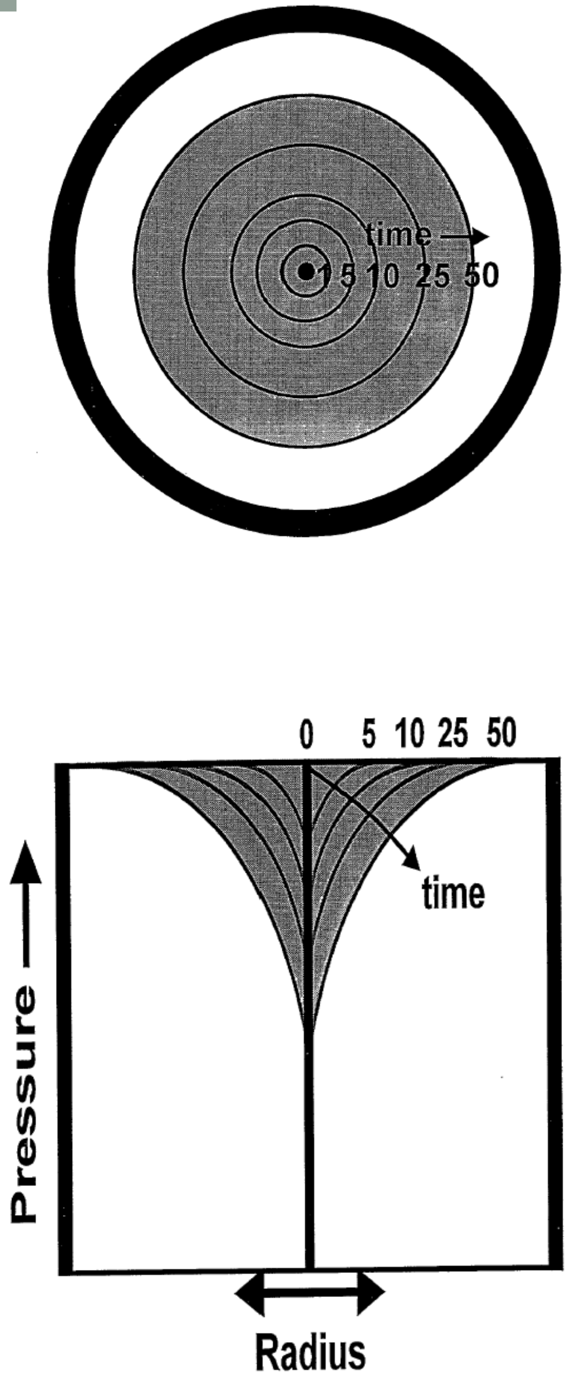
Primary Reservoir Characteristics

- Types of fluids in the reservoir
  - Incompressible fluids
  - Slightly compressible fluids
  - Compressible fluids
- Flow regimes
  - Steady-state flow
  - Unsteady-state flow
  - Pseudosteady-state flow
- Reservoir geometry
  - Radial flow
  - Linear flow
  - Spherical and hemispherical flow
- Number of flowing fluids in the reservoir.
  - Single-phase flow (oil, water, or gas)
  - Two-phase flow (oil–water, oil–gas, or gas–water)
  - Three-phase flow (oil, water, and gas)

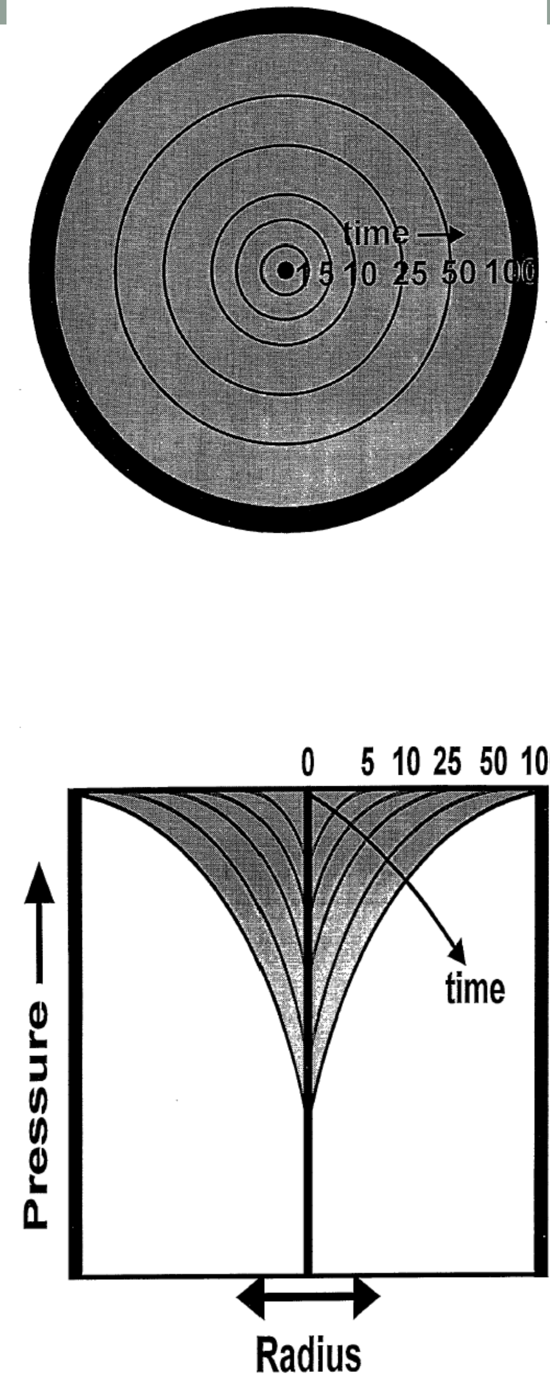
Flow Regimes



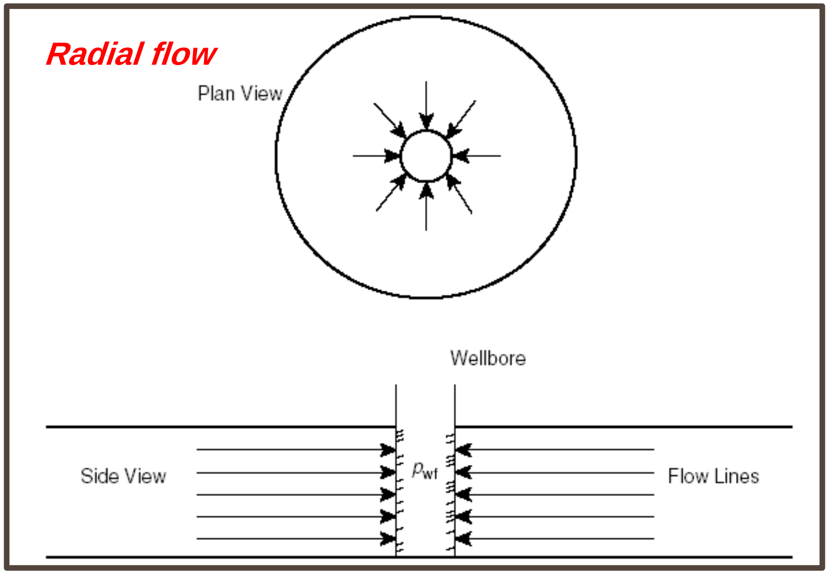
TRANSIENT

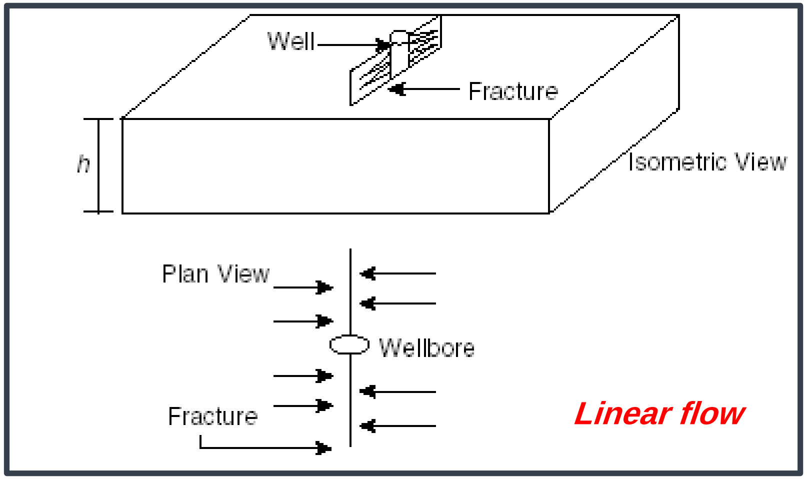


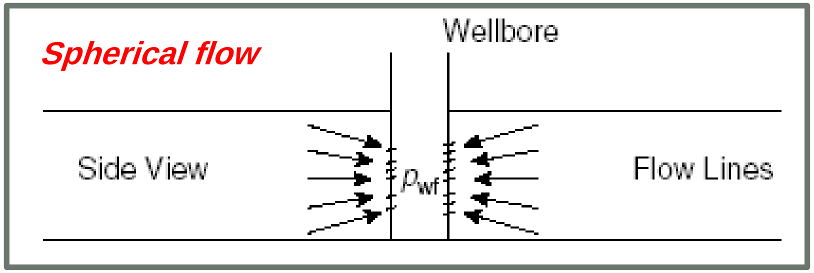
STABILIZED

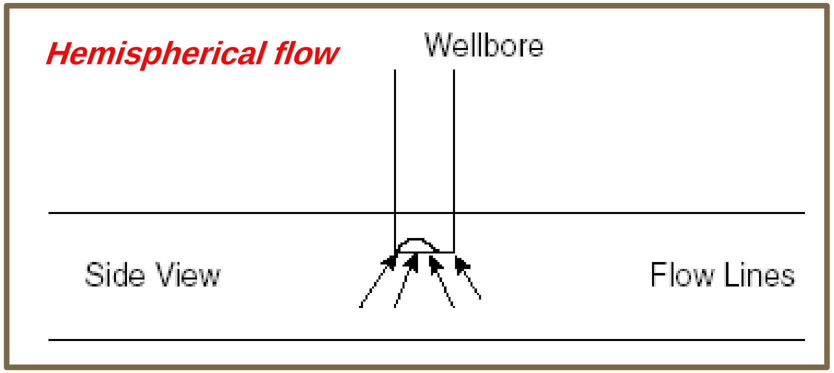


Reservoir Flow Geometry







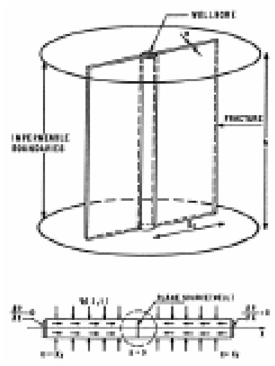


Components of Well Test Models

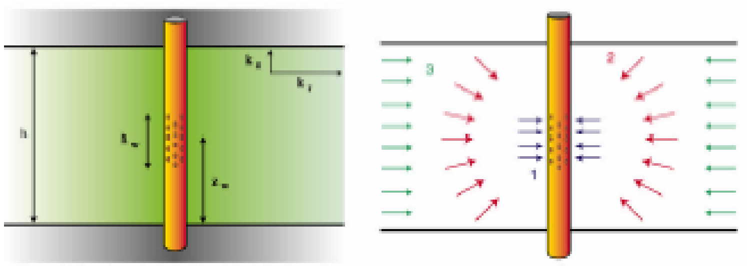
- **Well**
  - Direction (Vertical, Horizontal)
  - Storage (Constant, Changing)
  - Completion (Damaged, Fractured and Acidized)
- **Reservoir**
  - Homogeneous
  - Heterogeneous
  - Composite
  - Multilayer
  - Dual porosity
- **Boundaries**
  - Flow boundaries (No flow, Constant pressure, infinite)
  - Geometrical boundaries (Circular, Rectangular)

Well Models

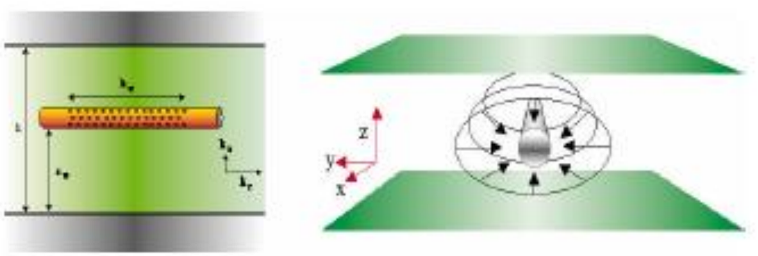
- ➢Wellbore Storage and Skin
- ➢Uniform Flux Vertical Fracture
- ➢Infinite Conductivity Vertical Fracture
- ➢Finite Conductivity Vertical Fracture
- ➢Horizontal Well
- ➢Limited Entry



b. Vertically Fractured Well: Uniform flux; infinite or finite fracture conductivity.



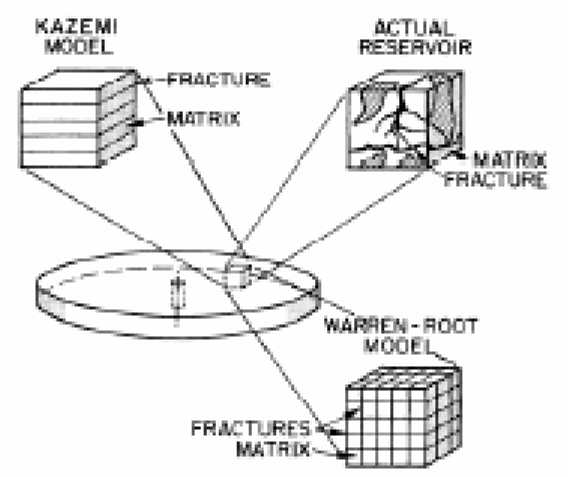
a. Vertical Well: Full or partial penetration, note that this model must also include permeability anistropy.

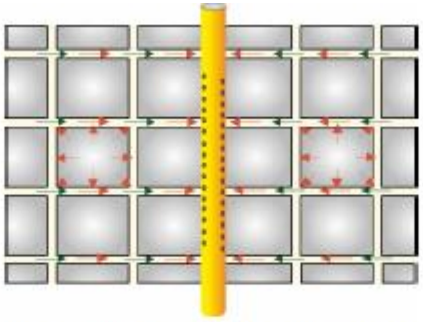


c. Horizontal Well: Full or partial penetra-tion — this model includes permeability anistropy and vertical position.

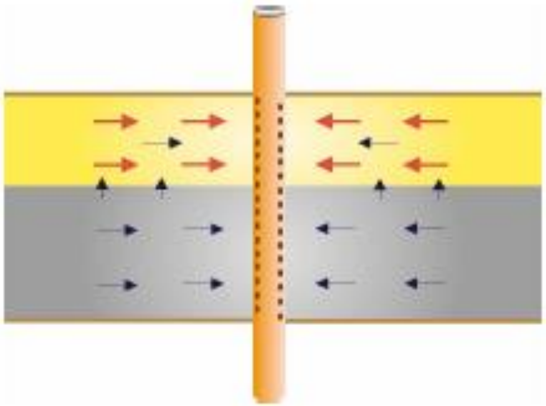
Reservoir Models

- Homogeneous
- Two-Layer
- Radial Composite
- Linear Composite
- Dual Porosity/Naturally Fractured
  - — Pseudosteady-state Interporosity Flow
  - — Transient Interporosity Flow (Slab/Sphere)

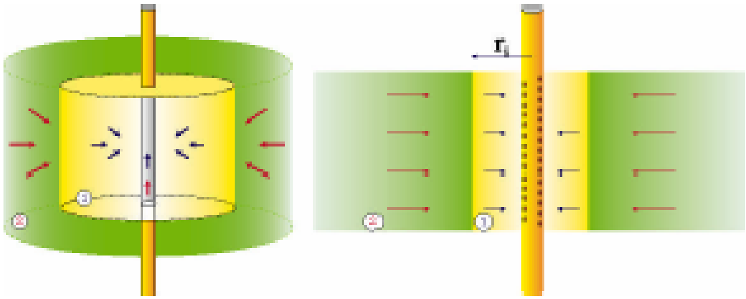




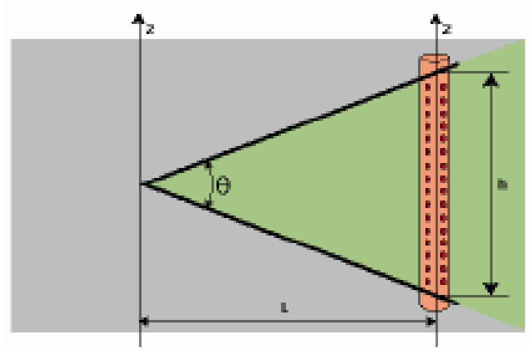
a. Vertical Well: Naturally fractured/ dual porosity reservoir system.



b. Vertical Well: Two-layer reservoir, with crossflow in the reservoir.



c. Vertical Well: Radial composite reservoir system.



d. Vertical Well: "Wedge" or pinch-out reservoir system.

Boundary Models

- Infinite-Acting
- Circle
- Rectangle
- Faults:
  - Single Fault
  - Parallel Faults
  - Multiple Intersecting Faults

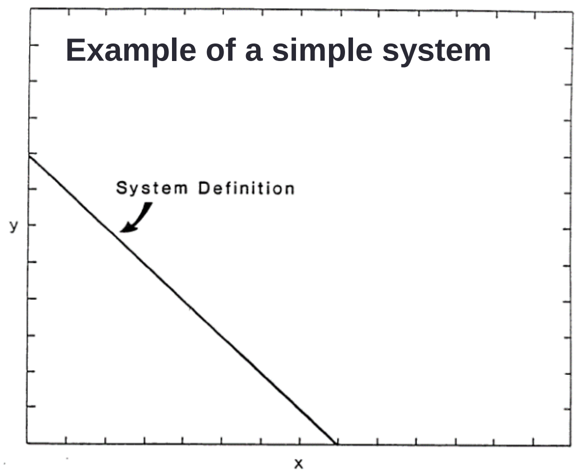
Direct versus Inverse Solutions

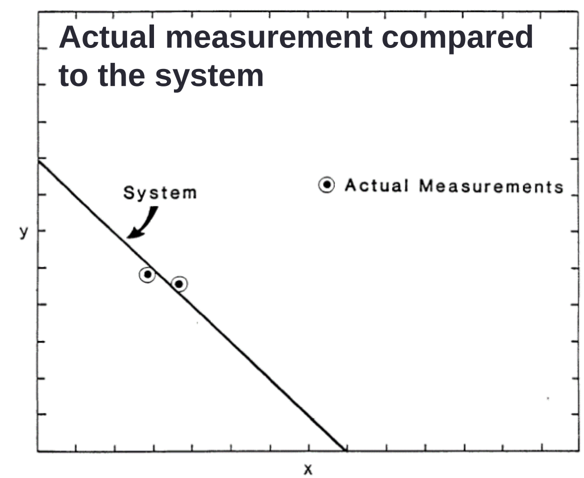
Direct solution

Input + system → Output (?)

Inverse solution

Input + System (?) → Output



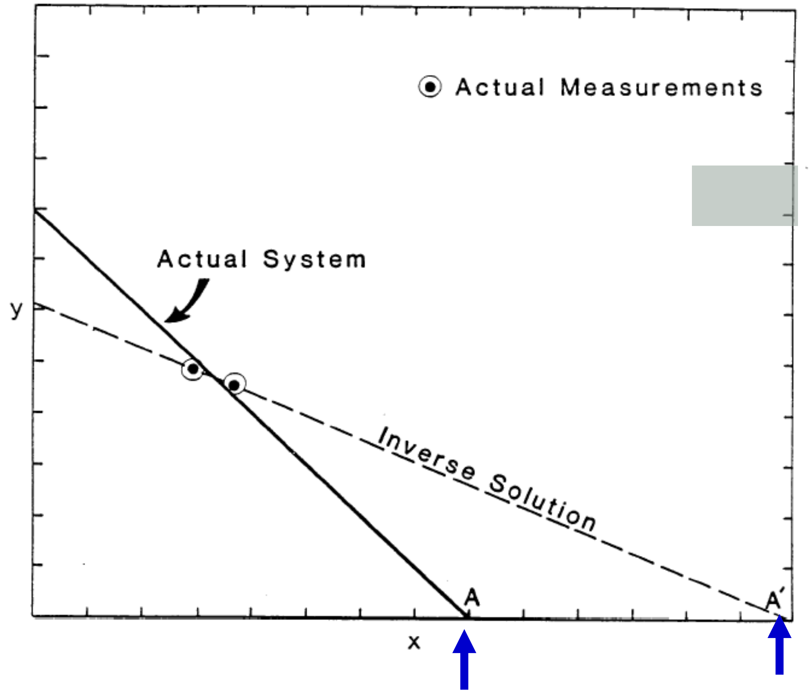


Inverse Solution Compared to Actual

➢Inverse solution can be used for the identification of system characteristics.

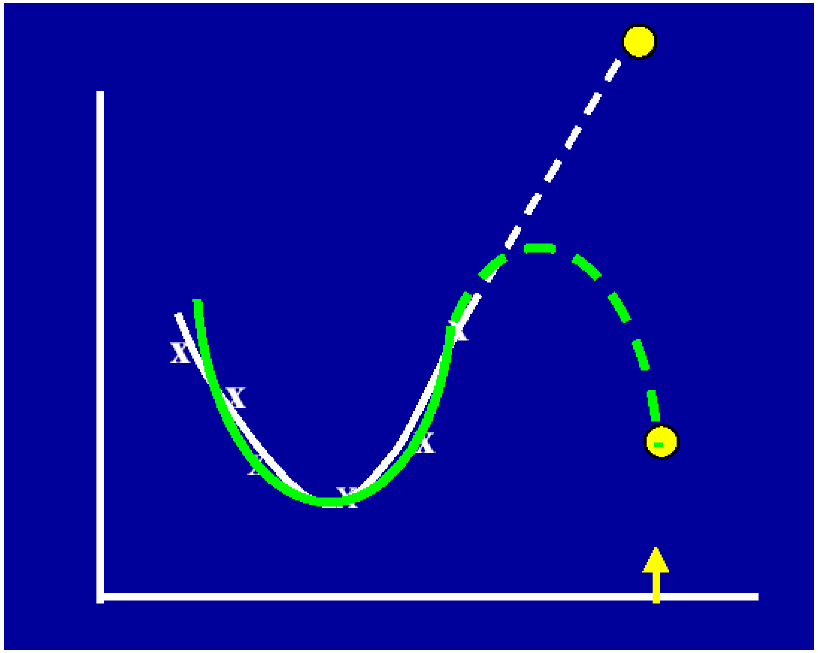
➢Inverse solution can result in grossly erroneous answers.

➢Whereas the mathematics is correct, the utility of the results derived from this mathematically process is questionable.



Characteristic of Inverse Solution

- Non-unique solution (the inverse solution has its limitation)
- A good looking history match is not a good enough answer



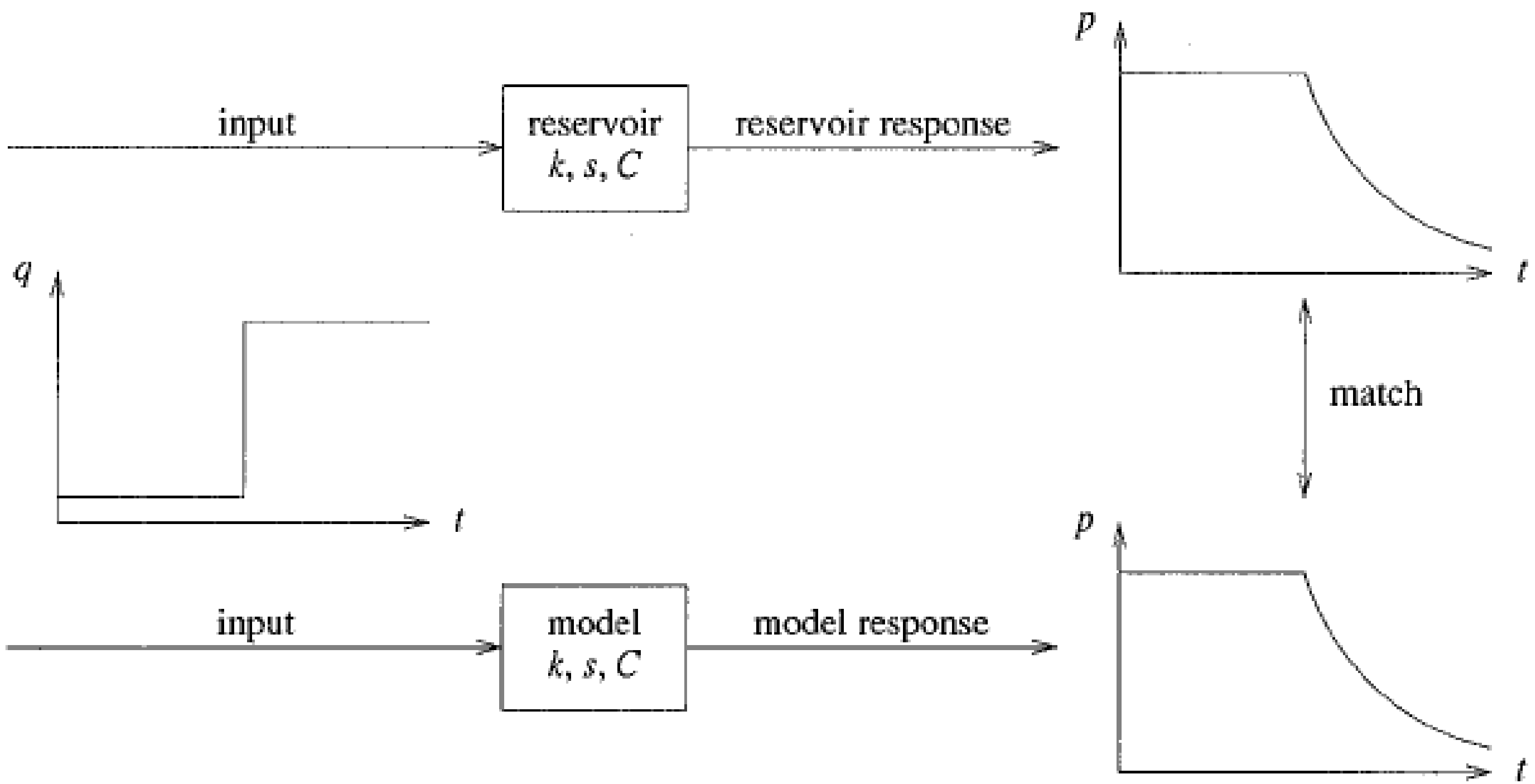
Input-System-Response

Input Perturbation → Reservoir Mechanism → Output Response

Well test interpretation is essentially an inverse problem and in general is better suited to analytical solution.

Model Input → Mathematical Model → Model Output

The objective of well test analysis is to describe an unknown system **S** (well + reservoir) by indirect measurements (**O** the pressure response to **I** a change of rate). Solving **S=O/I** is a typical inverse problem (Gringarten et al., 1979).


p
input
reservoir
k, s, C
reservoir response
t
q
match
t
p
input
model
k, s, C
model response
t

Input Data Required for Well Test Analysis

- **Test data:**
  - flow rate and bottom hole pressure as a function of time.
  - the test sequence of events must be detailed, including any operational problems that may affect the well response.

- **Well data:**
  - wellbore radius r_w
  - well geometry (such as inclined or horizontal well)
  - depths (formation, gauges)

- **Reservoir and fluid parameters:**
  - formation thickness h (net),
  - porosity Φ,
  - compressibility of oil $c_{o,}$ water c_w, and formation c_f
  - water saturation S_w,
  - oil viscosity μ
  - formation volume factor B

Principles of Transient Test Analysis

- The differential equation for fluid flow in a porous medium, the diffusivity equation is a combination of the law of conservation of matter, an equation of state, and Darcy's law. When expressed in radial coordinates, the diffusivity equation is:

$$(\partial^2 P/\partial r^2) + (1/r)(\partial P/\partial r) = (1/0.0002637)(\varphi \mu c_t/k)(\partial P/\partial r) \qquad (1)$$

- Note: all the equation in this course are in "oil field unites"

System of Units Used in well Test Analysis

Parameter	Nomenclature	SI-units	Field units
Flow rate	*q*	Sm3/d	STB/d
Volume factor	*B*	Rm3/Sm3	RB/STB
Thickness	*h*	m	ft
Permeability	*k*	µm2	mD
Viscosity	µ	mPa_s	cp
Pressure	*p*	kPa	psia
Radial distance	*r*	m	ft
Compressibility	*c*	$(kPa)^{-1}$	Psi^{-1}
Time	*t*	hrs	hrs
1 STB/d = 0.159 Sm^3/d 1 ft = 0.3048 m 1 mD = $0.987.10^3$ $µm^2$ 1cp = 1mPa.s 1 psi = 6.895 kPa			

- Comprehensive treatment of transient well testing normally use a general approach for providing solution to the diffusivity equation 1.
- The general solution rely on the concept of dimensionless pressure and dimensionless less time.
- The dimensionless – solution approach can be illustrated by starting with the familiar steady – state radial flow equation.
- $q= 0.007082 (kh(P_e-P_{wf})/B\mu \ln(r_e/r_w))$

- The equation may be solved for pressure difference:
- $P_e - P_{wf} = 141.2\ (qB\mu/kh)\ \ln(r_e/r_w)$
- Changing to dimensionless form, the radial flow equation becomes:
- $P_e - P_{wf} = 141.2\ (Bq\mu/kh)\ P_D$
- Where: $P_D = \ln(r_e/r_w)$
- Thus, the physical pressure drop in the steady-state radial flow situation is equal to a dimensionless pressure drop, which in this case is simply $\ln(r_e/r_w)$ times a scaling factor.

- The scaling factor depends on flow rate and reservoir properties only. The same concept applies to transient flow and to more complex situation, only the dimensionless pressure is different.
- In general terms, the pressure @ any point in a single – well reservoir being produced at constant rate q, is described with the generalized solution of equation 1:
- $Pi - P(r,t) = 141.2\ (qB\mu/kh)\ [P_D\ (r_D, t_D, c_D, \text{geometry}, ..)+S] \quad (2)$
- P_D is the dimensionless – pressure solution to equation1 for the appropriate boundry condition and S is the skin effect,

- A dimensionless pressure drop assumed to occur at the wellbore face as a result of wellbore damage on improvement. Skin effect ,s , only appears in equation when r_D=1.
- In transient flow, P_D is always a function of dimensionless time:
- $t_D = (0.0002637kt/\varphi\mu c_t\ r_w^2)$ (3a)
- When basal on wellbore radius – and
- $t_{DA} = (0.0002637\ kt/\ \varphi\mu c_t A) = t_D\ (r_w^2/A)$
- $r_D = r/r_w$
- Dimensionless pressure, P_D is a solution to equation 1 for specific boundary condition and reservoir geometry. Practically speaking, P_D is just a number given by an equation a table or graph.

Skin Effect

SEM examples of various clays which can cause formation damage

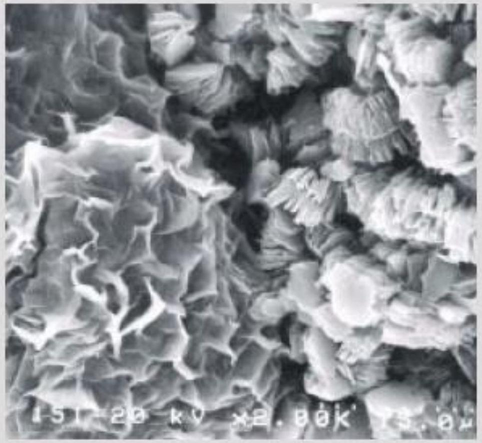


Fig. 13. Smectite (left) and kaolinite (right) coat grains and fill a pore. Note distinct differences in morphology of each clay ("honeycomb" smectite; vermicular booklets of kaolinite (x2000)
(image courtesey of Westport Technology Center)

Fig. 14. Delicate wisps of "hairy" illite project into a pore. Note that the fibers not only form a highly rugose surface within the pore, but the fibers could break and migrate under extreme fluid pressures (x2500)
(image courtesey of Westport Technology Center)

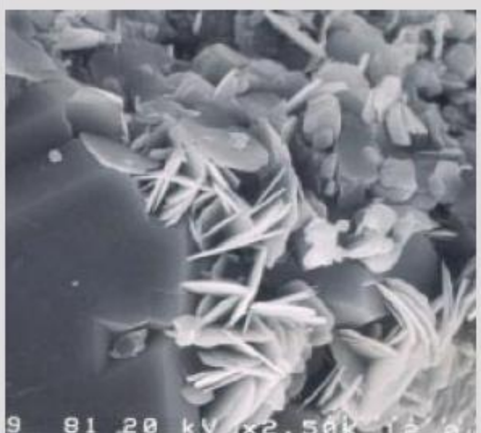


Fig. 15. Well-formed chlorite platelets form partial rosettes adjacent to, and coating quartz overgrowths (x2500)
(image courtesey of Westport Technology Center)

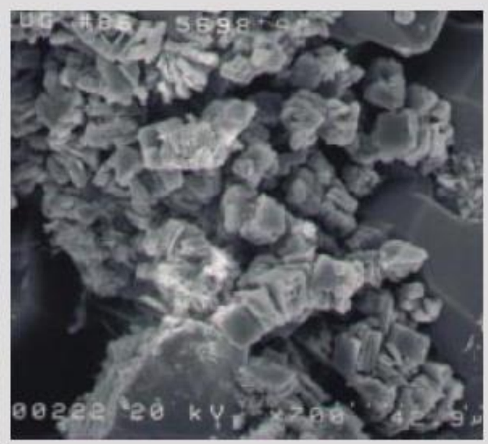


Fig. 16. Well-formed, but rather randomly oriented kaolinite booklets post-date quartz overgrowths (x700)
(image courtesey of Westport Technology Center)

SEM examples of formation damage and stimulation

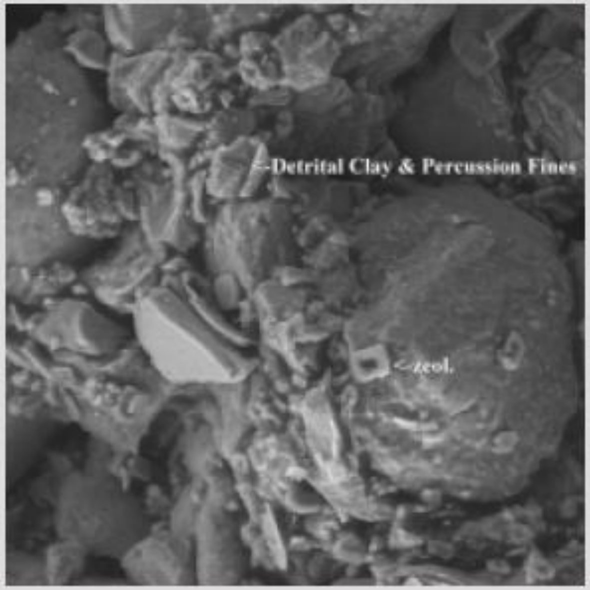


Fig. 17. SEM image of perforation damage with percussion fines (x305)

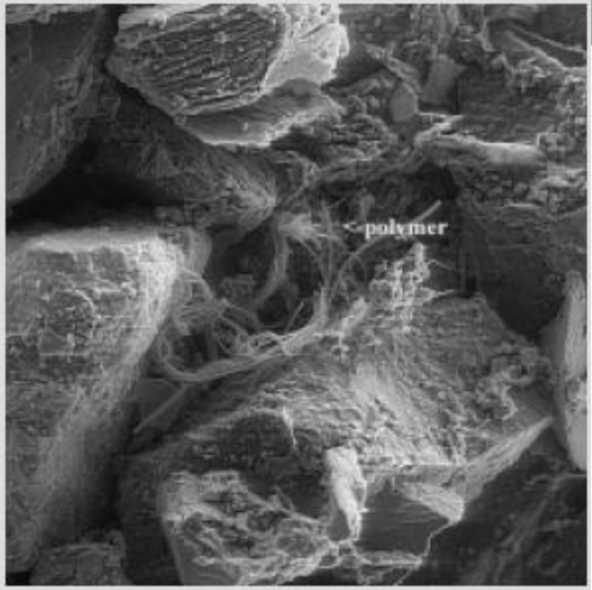


Fig. 18. SEM image of completion damage with polymer filament (x105)

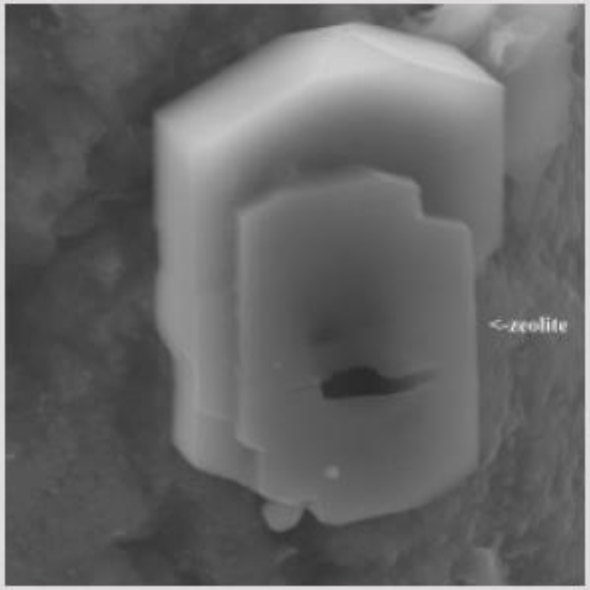


Fig. 19. SEM image of pre-acid treatment (x3100)

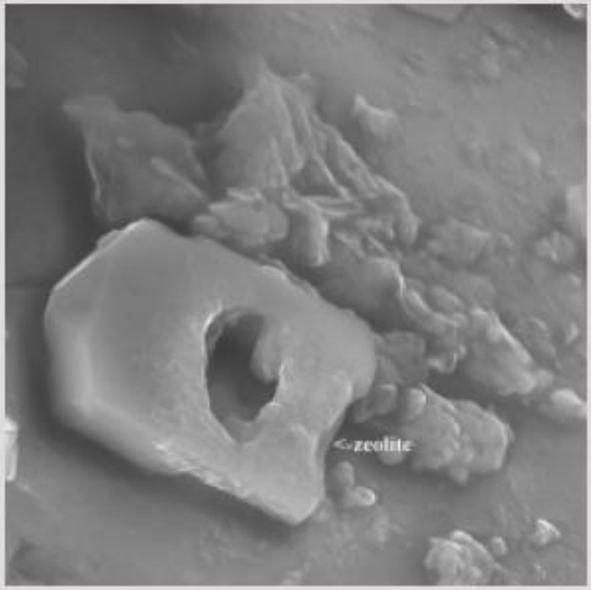
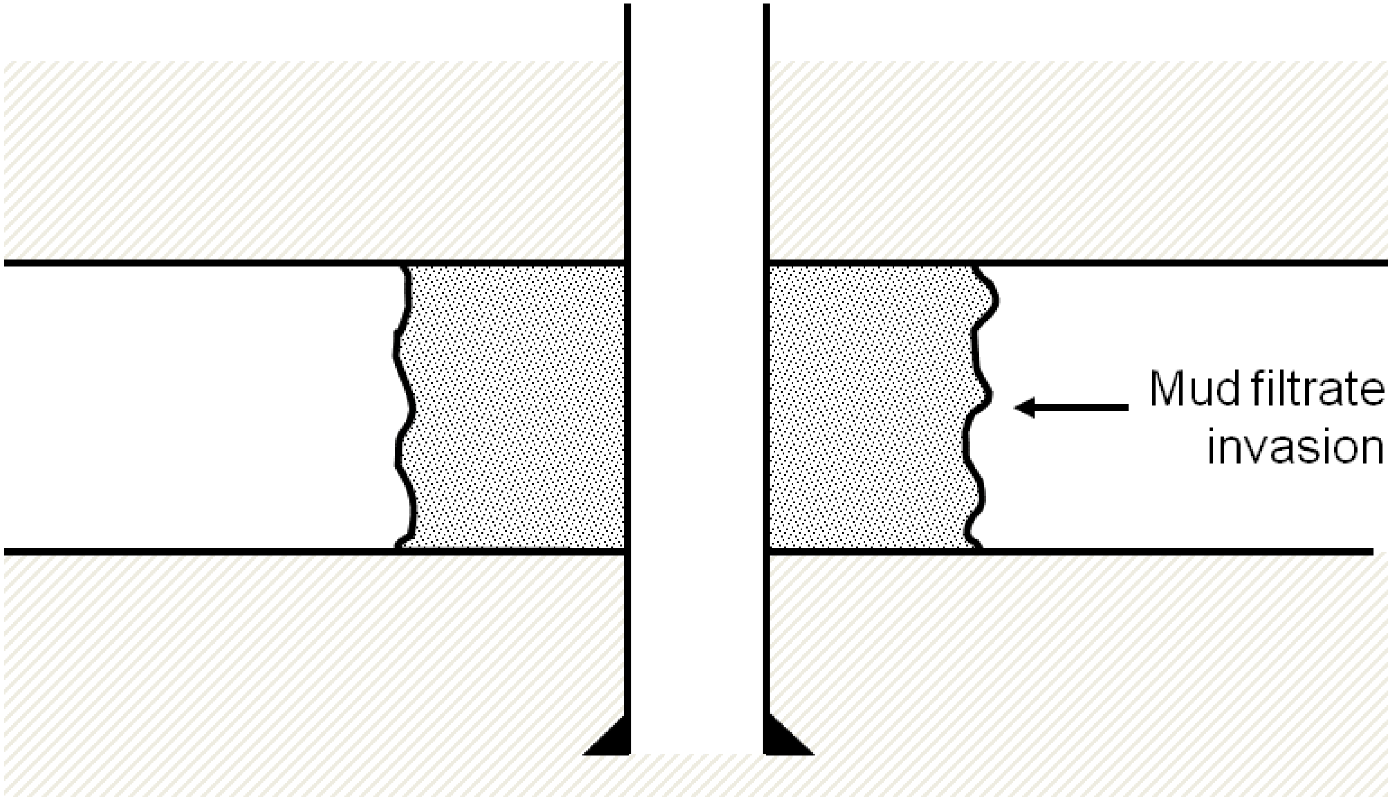


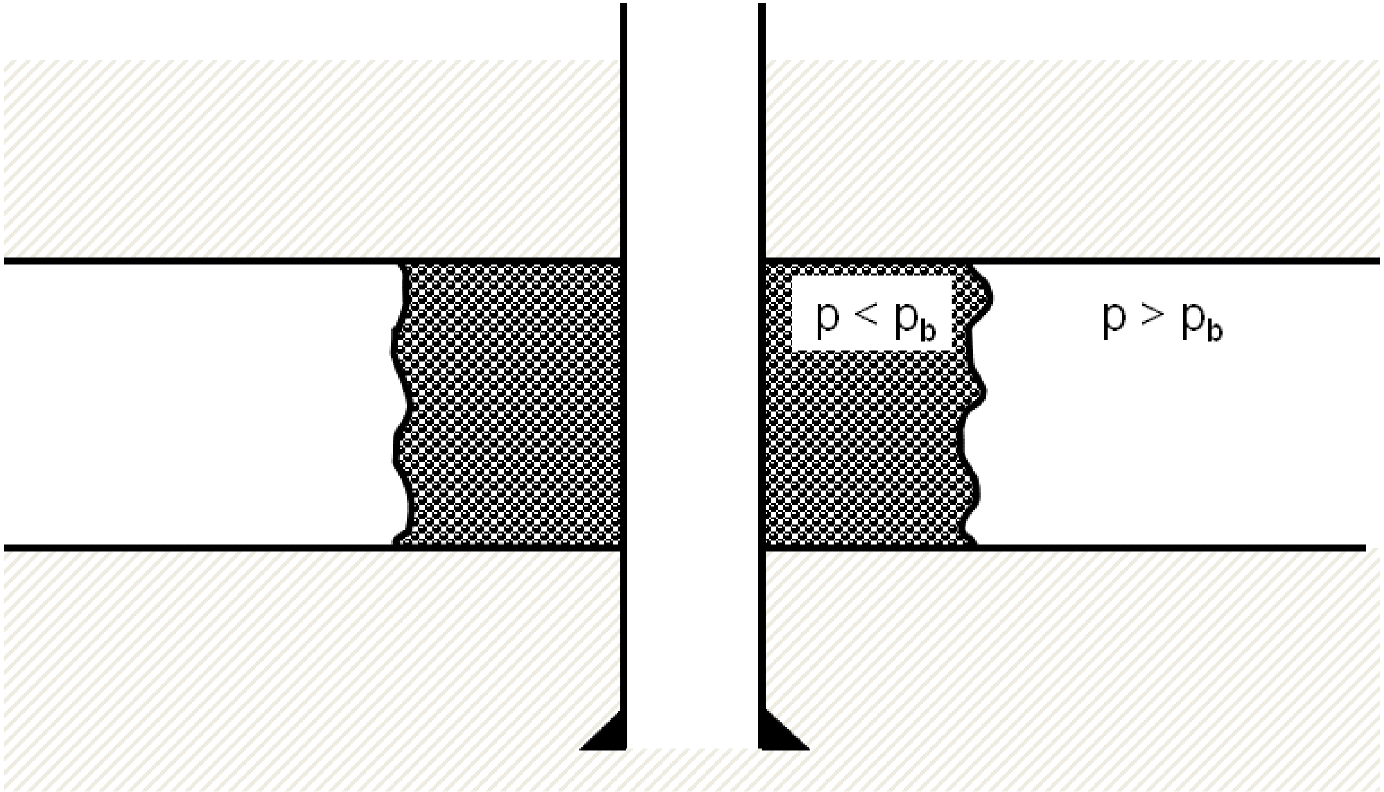
Fig. 20. SEM image of post-acid treatment (x3100)

Damage Caused by Drilling Fluid



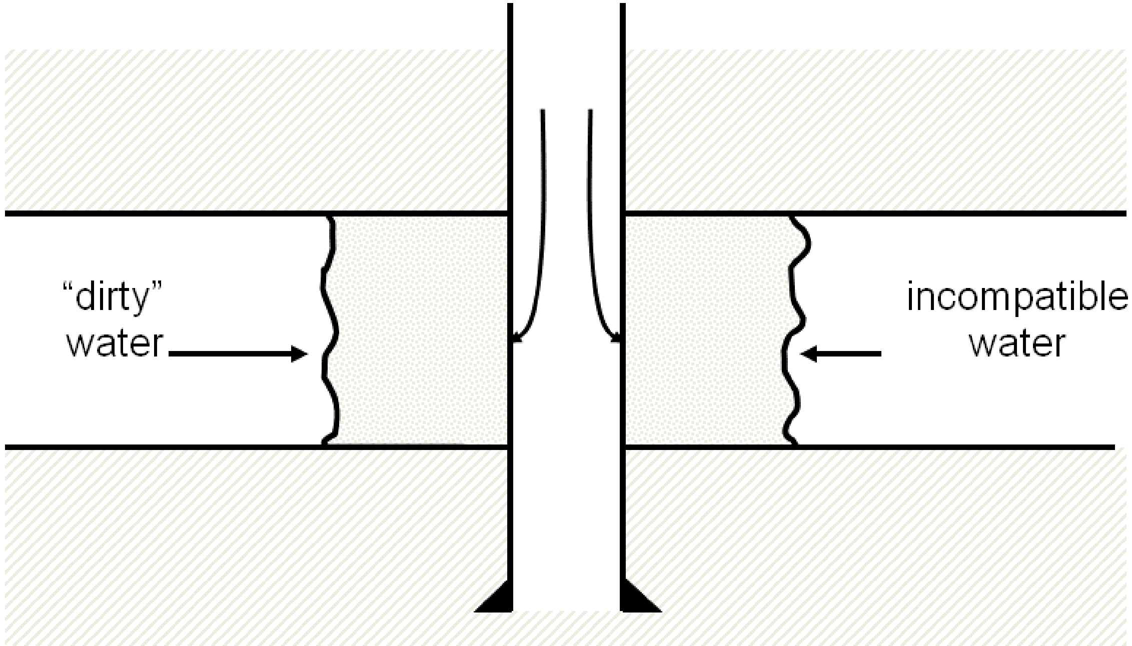
- Mud filtrate invasion reduces effective permeability near wellbore.
- Mud filtrate may cause formation clays to swell, causing damage.

Damage Caused by Production



- In an oil reservoir, pressure near well may be below bubble point, allowing free gas which reduces effective permeability to oil near wellbore.
- In a retrograde gas condensate reservoir, pressure near well may be below dewpoint, allowing an immobile condensate ring to build up, which reduces effective permeability to gas near wellbore.

Damage Caused by Injection



- Injected water may not be clean - fines may plug formation.

- Injected water may not be compatible with formation water - may cause precipitates to form and plug formation.

- Injected water may not be compatible with clay minerals in formation; fresh water can destabilize some clays, causing movement of fines and plugging of formation.

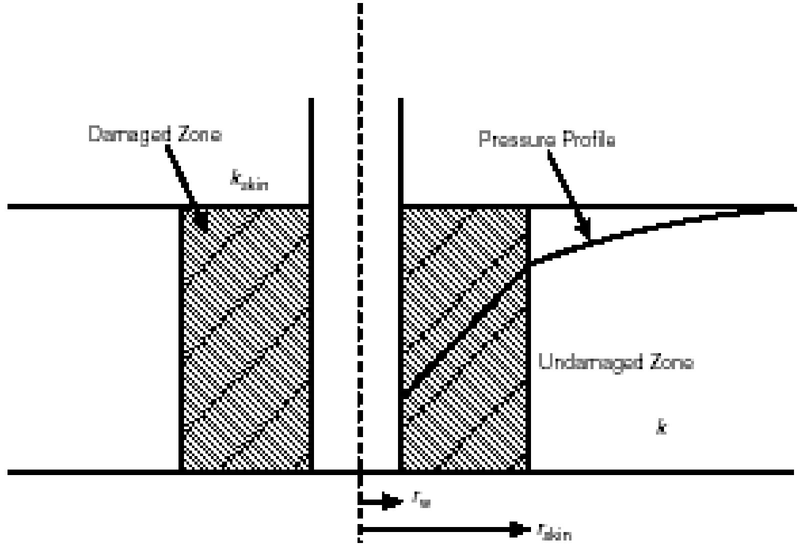
Skin

•**Skin zone**: The region of altered permeability (A few inches to several feet from the wellbore). The effect of the skin zone is to alter the pressure distribution around the wellbore.

•**Wellbore damage** : reduction of the permeability around the wellbore due to entrance of materials such as mud filtrate, cement slurry, or clay particles during drilling, completion, or workover operations.

•**Wellbore stimulation** : increasing of the permeability near the wellbore using:

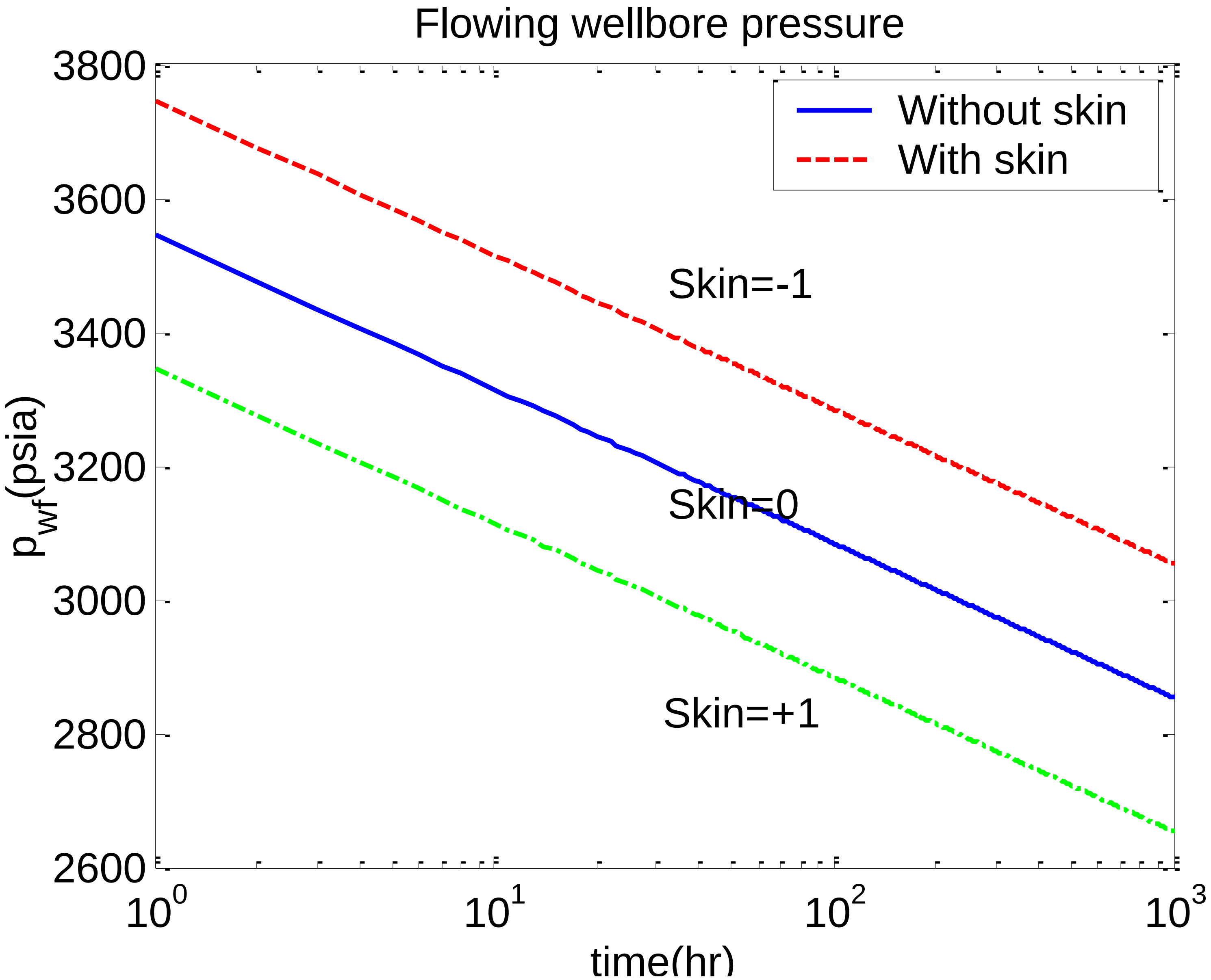
- •Acidizing
- •Fracturing



•In case of wellbore damage, the skin zone causes an additional pressure loss in the formation.

•In case of wellbore improvement, the opposite to that of wellbore damage occurs.

$$\Delta P_{skin} > 0 \rightarrow \text{Damage}$$
$$\Delta P_{skin} < 0 \rightarrow \text{Stimulation}$$
$$\Delta P_{skin} = 0 \rightarrow \text{No damage or stimulation}$$

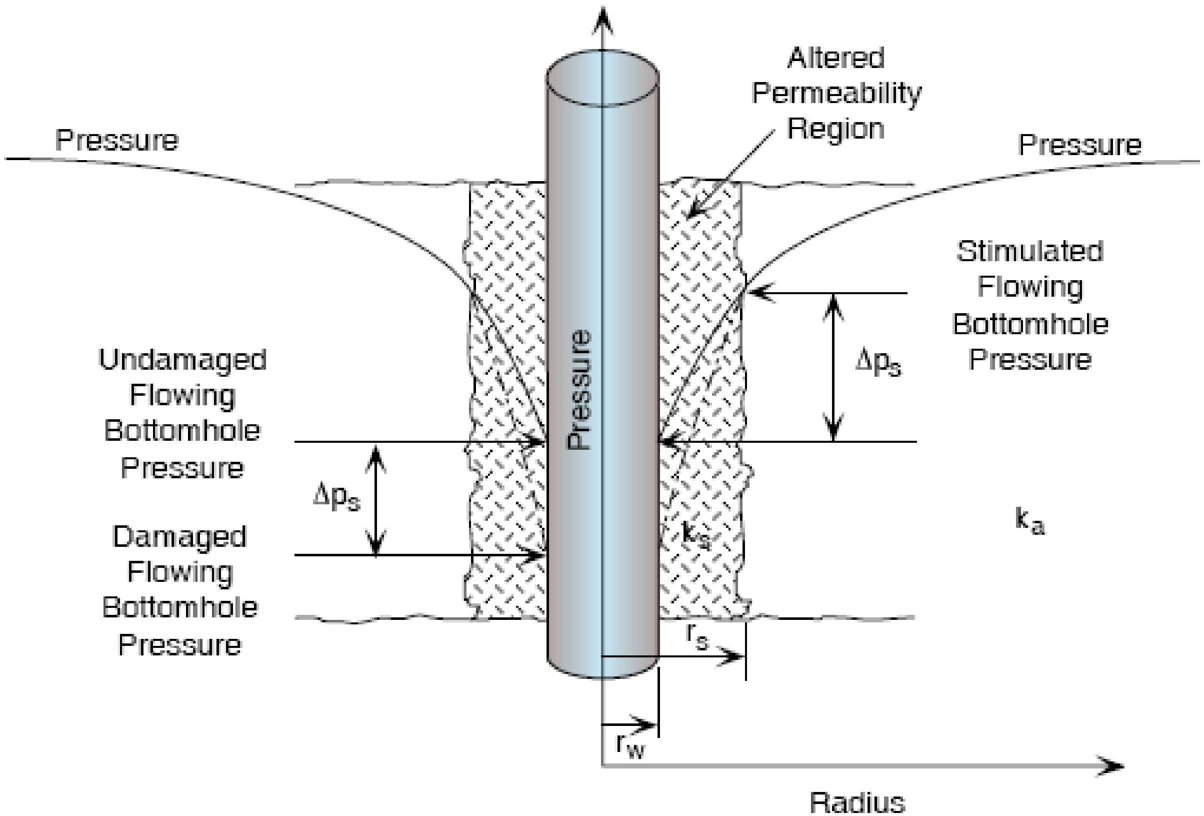


Flowing wellbore pressure
3800
3600
3400
3200
3000
2800
2600
p_{wf}(psia)
10^0
10^1
10^2
10^3
time(hr)
Without skin
With skin
Skin=-1
Skin=0
Skin=+1

Skin

- The skin effect, first introduced by van Everdingen and Hurst (1949) defines a steady-state pressure difference around the wellbore.

Schematic of the Skin Effect



Skin Development

Skin, S, refers to a region near the wellbore of improved or reduced permeability compared to the bulk formation permeability.

Impairment (+S):

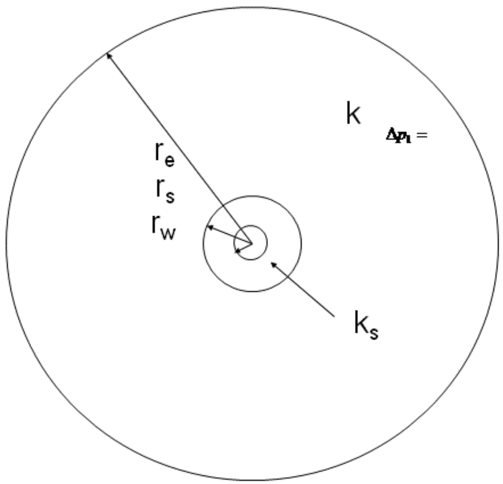
- Overbalanced drilling (filtrate loss)
- Perforating damage
- Unfiltered completion fluid
- Fines migration after long term production
- Non-darcy flow (predominantly gas well)
- Condensate banking- acts like turbulence

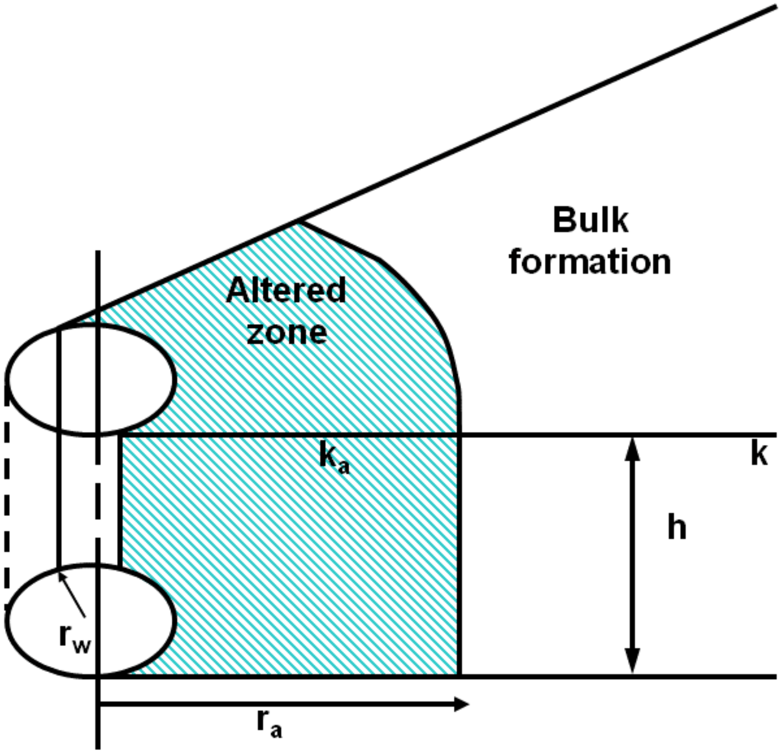
Stimulation (-S)

- Frac pack (0 to -0.5)
- Acidizing
- Hydraulic fracturing

Generally S>5 is considered bad; S= -3.5 to -4 is excellent.

Reservoir Model of Skin Effect





Effective Wellbore Radius

- If the permeability in the altered zone k_a is much larger than the formation permeability k, then the wellbore will act like a well having an apparent wellbore radius r_{wa}.

- The apparent wellbore radius may be calculated from the actual wellbore radius and the skin factor.

$$s = -\ln\left(\frac{r_{wa}}{r_w}\right) \Longrightarrow r_{wa} = r_w e^{-s}$$

Minimum Skin Factor

The minimum skin factor possible (most negative skin factor) would occur when the apparent wellbore radius r_{wa} is equal to the drainage radius r_e of the well.

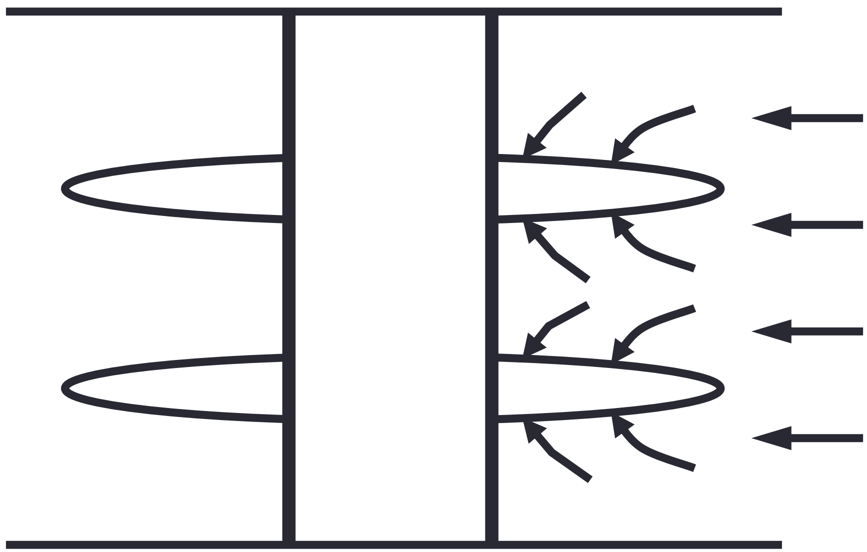
$$s_{min} = -\ln\left(\frac{r_e}{r_w}\right)$$

For a circular drainage area of 40 acres (r_e = 745 feet) and a wellbore radius of 0.5 feet, this gives a minimum skin factor (maximum stimulation) of -7.3.

$$s_{min} = -\ln\left(\frac{r_e}{r_w}\right) = -\ln\left(\frac{745}{0.5}\right) = -7.3$$

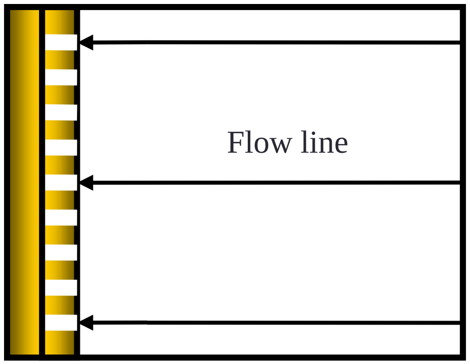
Geometric Skin - Converging Flow to Perforations

When a cased wellbore is perforated, the fluid must converge to one of the perforations to enter the wellbore. If the shot spacing is too large, this converging flow results in a positive apparent skin factor. This effect increases as the vertical permeability decreases, and decreases as the shot density increases.

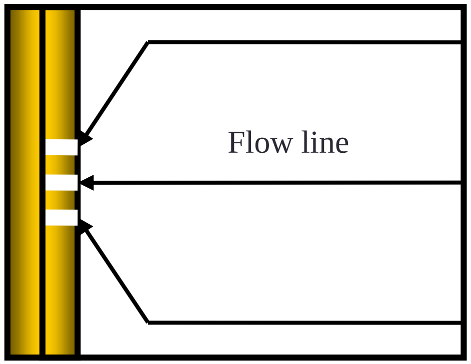


Limited Flow Entry

The partial penetration skin is used when the perforations of a vertical wellbore do not span the entire net pay of the reservoir. In these situations, the reservoir flow has to flow vertically and the flow lines converge at the perforations.



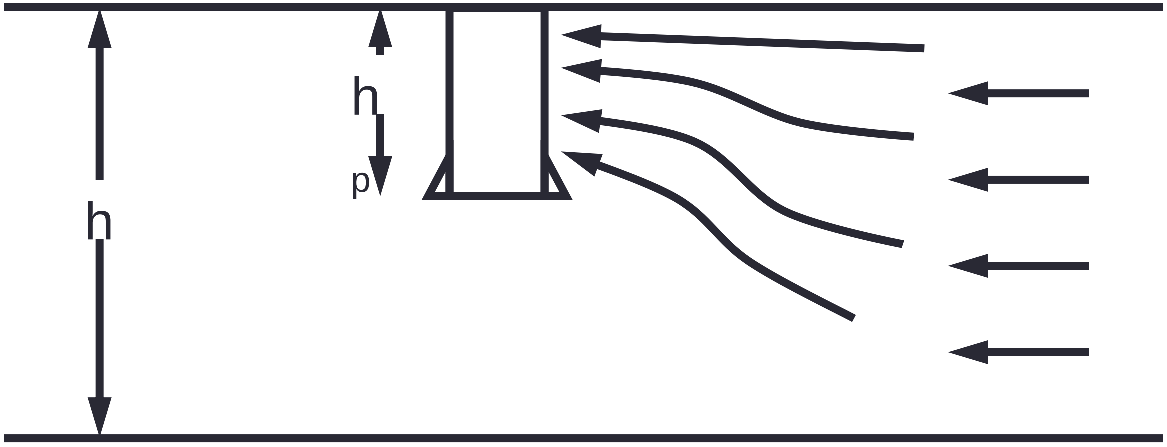
(a) Complete penetration



(b) Partial penetration

Geometric Skin - Partial Penetration1

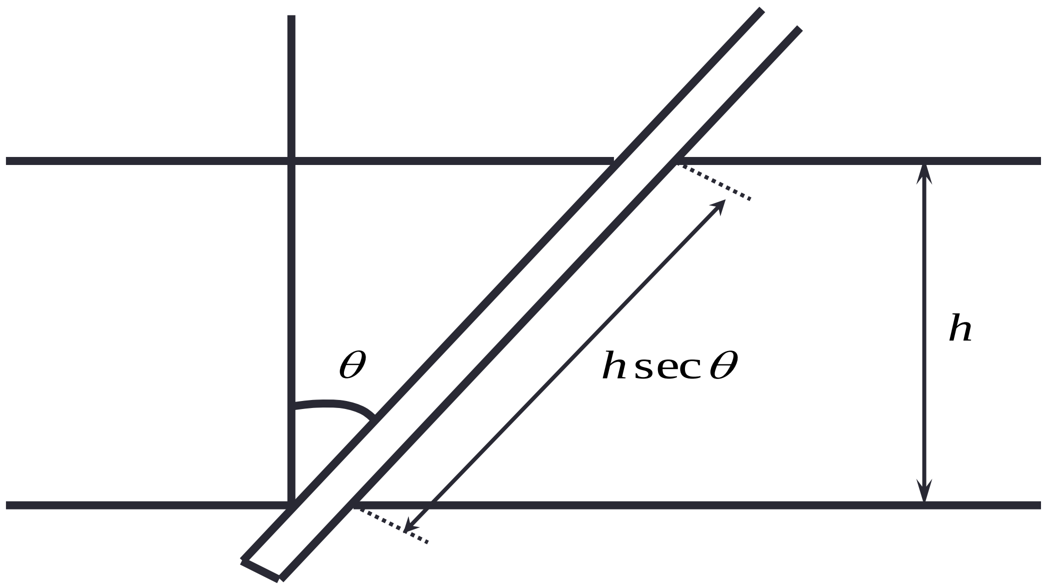
When a well is completed through only a portion of the net pay interval, the fluid must converge to flow through a smaller completed interval. This converging flow also results in a positive apparent skin factor. This effect increases as the vertical permeability decreases and decreases as the perforated interval as a fraction of the total interval increases.



Geometric Skin - Deviated Wellbore

When a well penetrates the formation at an angle other than 90 degrees, there is more surface area in contact with the formation. This results in a negative apparent skin factor. This effect decreases as the vertical permeability decreases, and increases as the angle from the vertical increases.

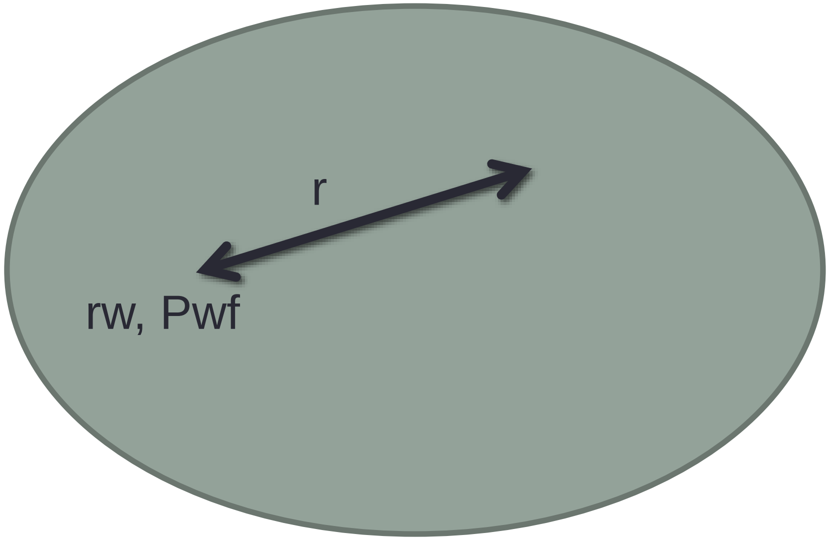
$$s = s_d + s_\theta$$

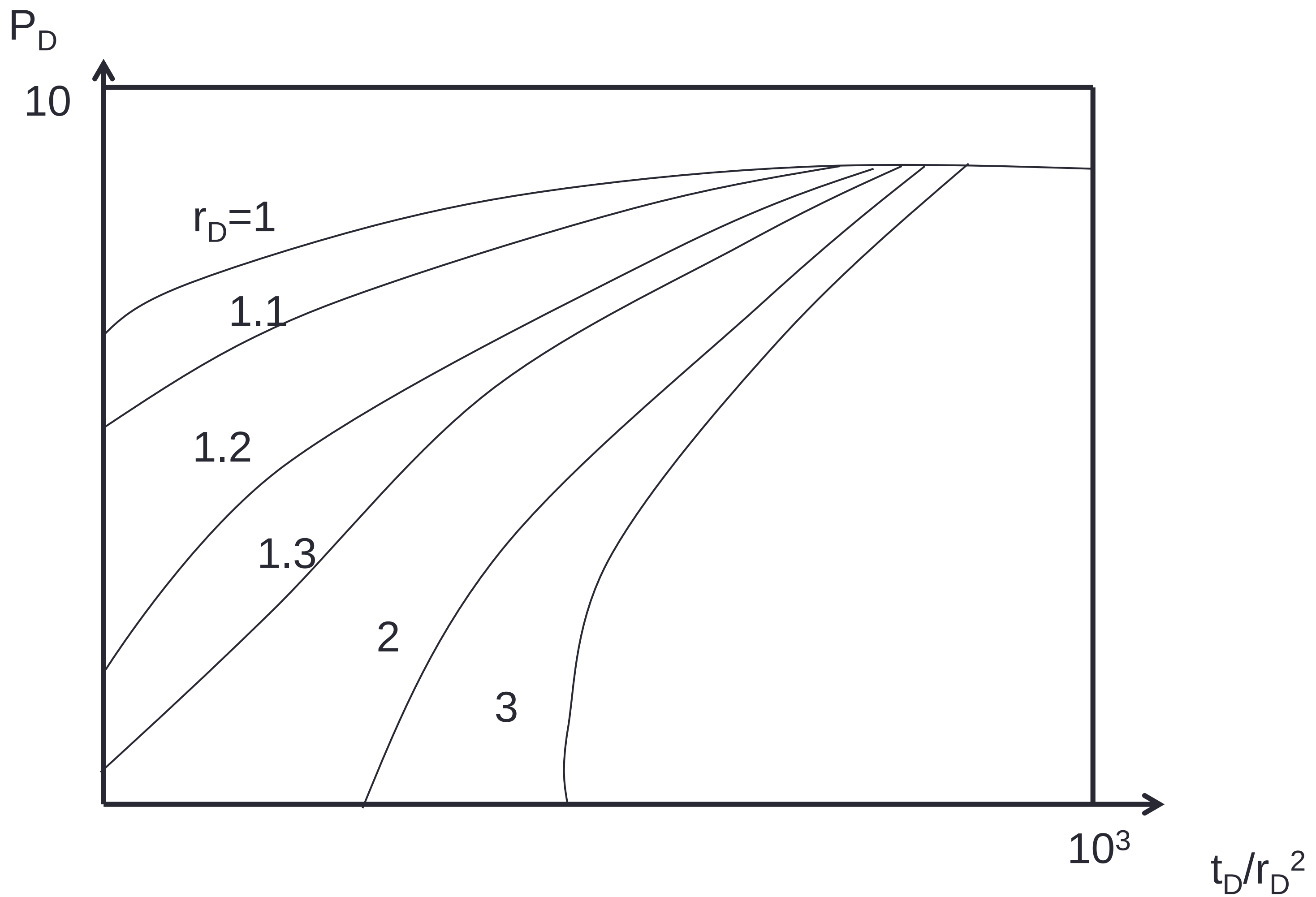


- **Dimensionless pressure during the infinite – acting flow period:**

This figure is a schematic presentation of a single well producing at constant rate q in an infinite, Horizontal, thin reservoir containing a single phase, slightly compressible fluid.

When assumption of equation 1 are satisfied equation 2 with P_D from figure in the next slide, describes the pressure behavior at any point in the system.




P_D
10
$r_D=1$
1.1
1.2
1.3
2
3
10^3
t_D/r_D^2

- The exponential – integral solution (also called the line – source solution) to the flow equation is:

$P_D\ (t_D, r_D\ ) = -\ ½\ Ei\ (-r_D^2\ /\ 4t_D) = ½[\ln(t_D/r_D^2) + 0.80907]$ (4)

Equation 4 may be used when: $t_D/r_D^2 > 100$

The exponential integral is defined by :

$Ei(-x) = -\int_x^{\infty} (e^{-u}/u)\ du$ (5)

Values may be taken from table or may be approximated from:

$Ei\ (-x) = \ln(x) + 0.5772$ for $x<0.0025$

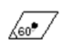
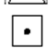
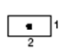
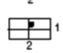
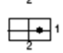
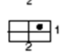
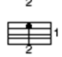
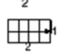
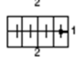
- As mention previously, all wells are infinite – acting for some time after a change in rate. For Drawdown, the duration of the infinite – acting period may be estimated from:
- $t_{eia}= (\varphi\mu c_t A/ 0.0002637\ k)\ (t_{DA})_{eia}$
- teia= end of infinite acting time (hrs)
- K: md
- A: ft^2
- C_t: psi^{-1}
- (t_{DA}) eia: from table
- For a well in the center of a closed circular reservoir:
- $(t_{DA})_{eia}=0.1$ and $t_{eia}= 380\ \varphi\mu c_t A/k$

Dimensionless pressure during the pseudo steady – state flow period:

- In closed system a transition period follows the infinite – acting transient response. That is followed by pseudo steady – state flow period, a transient flow regime when the pressure change with time, dP/dt is constant at all point in the reservoir (that is equivalent to the right – hand side of equation 2 being constant). During pseudo steady – state, P_D is given by:
- $P_D = 2\Pi t_{DA} + ½ \ln(A/r_w^2) + 1.2 \ln(2.2458/c_A)$ (7)

- c_A the shape factor, is a geometric factor characteristic of the system shape and the well location. Both c_A and the final term in equation 7 are given in table below.

Table 1.4 *Shape factors for various single-well drainage areas (After Earlougher, R, Advances in Well Test Ana permission to publish by the SPE, copyright SPE, 1977)*

In bounded reservoirs	C_A	$\ln C_A$	$\frac{1}{2}\ln\left(\frac{2.2458}{C_A}\right)$	*Exact for* t_{DA} >	*Less than 1% error for* t_{DA} >	*Use infinite syster solution with less than 1% error for* t_{DA} >
	31.62	3.4538	−1.3224	0.1	0.06	0.10
	31.6	3.4532	−1.3220	0.1	0.06	0.10
	27.6	3.3178	−1.2544	0.2	0.07	0.09
	27.1	3.2995	−1.2452	0.2	0.07	0.09
	21.9	3.0865	−1.1387	0.4	0.12	0.08
	0.098	−2.3227	+1.5659	0.9	0.60	0.015
	30.8828	3.4302	−1.3106	0.1	0.05	0.09
	12.9851	2.5638	−0.8774	0.7	0.25	0.03
	10132	1.5070	−0.3490	0.6	0.30	0.025
	3.3351	1.2045	−0.1977	0.7	0.25	0.01
	21.8369	3.0836	−1.1373	0.3	0.15	0.025
	10.8374	2.3830	−0.7870	0.4	0.15	0.025
	10141	1.5072	−0.3491	1.5	0.50	0.06
	2.0769	0.7309	−0.0391	1.7	0.50	0.02
	3.1573	1.1497	−0.1703	0.4	0.15	0.005
	0.5813	−0.5425	+0.6758	2.0	0.60	0.02
	0.1109	−2.1991	+1.5041	3.0	0.60	0.005

- If 31.62, the c_A value for a well in the center of a circular system is used in equation 7, the last two terms become the familiar $\ln(r_e/r_w) - 0.75$.
- Equation 7 applies any time after pseudo steady – state flow begins, that time may be estimated from:
- $t_{pss} = (\varphi \mu c_t A / 0.0002637\ k)\ (t_{DA})_{pss}$ (8)
- $(t_{DA})_{pss}$ = from table

Steady – state flow:

- When the pressure at any point in a system does not vary with time (that is when the right – hand side of equation 1 is zero) flow is said to be steady state, the dimensionless pressure function are:
- Steady state linear: $(P_D)_{ssl}=2\Pi Lh/A$ (9a)
- Steady state radial: $(P_D)_{ssr}=\ln(re/rw)$ (9b)
- When equation 9b is used in equation 2, we obtain after rearrangement:
- $q= (0.007082kh(P_e-P_{wf})/B\mu\ln(re/rw))$
- The familiar form of the Darcy's low.
- In reservoir, steady state flow can occur only when the reservoir is completely recharged by a strong aquifer or when injection and production are balanced.

Radius of drainage and stabilization time:

- stabilization time has been defined in many ways by various authors. Most definitions corresponds to the beginning of the pseudo steady state flow period. Using that as the definition of stabilization time, we can estimate the stabilization time for any shape given table 1 from equation 8.
- For a well in the center of most symmetrical shapes, draw down stabilization time is estimated from:
- $ts=380\ \varphi\mu c_t A/k$ (10a)
- Where ts is in hours,

If we assume the system is radial:

$ts=1200\ \varphi\mu c_t r^{e2}/k$ (10b)

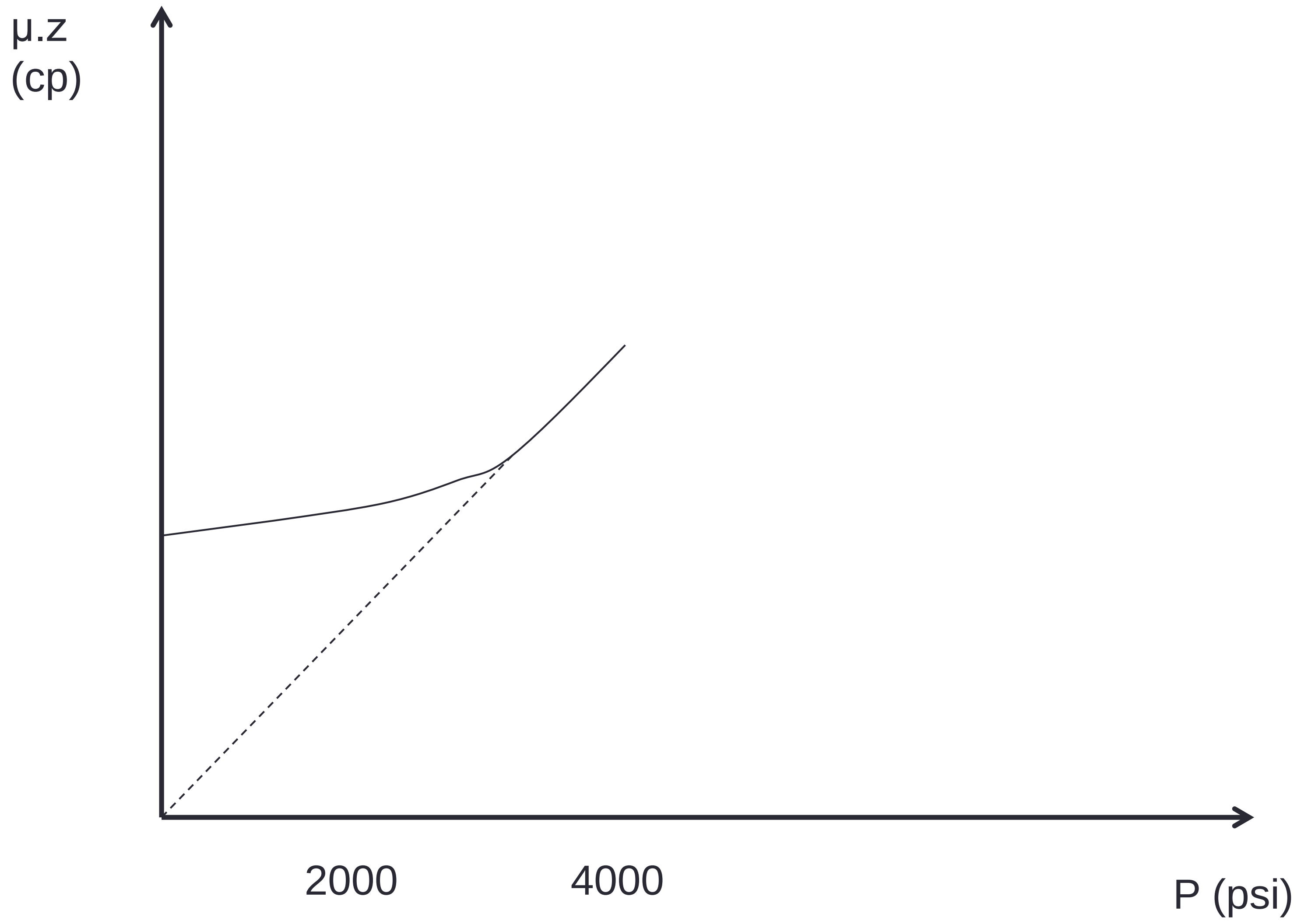
- Radius of drainage is also defined in several ways.
- In most definitions, the radius of drainage defines a circular system with a pseudo steady state pressure distribution from the wellbore to the drainage radius as time increases, more of the reservoir is influenced by the well and the radius of drainage increases, as given by:
- $rd = 0.029 \sqrt{(kt/\varphi \mu c_t)}$ (11)
- rd : ft
- Eventually, rd must stop increasing either when reservoir boundary or drainage region of adjacent wells are encountered. So equation 11can apply till t_{pss}.

Application of flow equation to gas system:

- Gas reservoir and density vary significantly with pressure, so the assumption of equation 1 are not satisfied for gas system and the equation does not apply directly to gas flow in porous media. The difficulty is avoided by defining a ‘real gas potential’ (real gas pseudo pressure or just pseudo pressure).
- $m(p) = 2\int_{Pb}^{p} (P/\mu(p)\, z(p))\, dp$ (12)
- Where Pb: base pressure

- When the real gas potential is used, equation 1 essentially retains its form but with m(p) replacing p. at equation can be solved and analogy to equation 2 can be written with $m_D(t_D)$ in place of $P_D(t_D)$.
- For radial gas flow it has been shown that when $t_D<(t_D)_{pss}$:
- $m_D(t_D)=P_D(t_D)$ (13)
- Using equation 13, the gas analog of equation 2, and substituting the appropriate gas properties, the flow equation for a real gas is:
- $m(p_{wf})=m(p_i) – 50300(p_{sc}/T_{sc})(qT/kh)$ [$p_D(t_D)$ + S+ D(q)] (14)
- q: Mscf/D

- The term D(q) accounts for non-Darcy flow around the well bore. To use equation 14 it is necessary to construct a high resolution graph of m(p) vs. p from the viscosity and z factor for the gas.
- As result of the characteristics of the real gas potential, equation 14 can be simplified for certain pressure range. Figure in the next slide shows $\mu.z$ as a function of pressure for typical gas.



μ.z
(cp)
2000
4000
P (psi)

- At low pressure μ.z is essentially constant, while at high pressure it is essentially directly proportional to pressure.
- When this behavior is used in equation 12, equation 14 can be simplified to:
- P_{wf}= Pi-50300 ($Zi\mu_{gi}$/2Pi) (P_{sc}/T_{sc})(qT/kh) [$P_D(t_D)$+S+D(q)]   (15)
- At high perssure,
- At low pressure it becomes:
- P_{wf}^2= Pi^2 -50300 ($Zi\mu_{gi}$) (P_{sc}/T_{sc})(qT/kh) [$P_D(t_D)$+S+D(q)]   (16)
- Equation 16 generally applies when p<2000 psi, while equation 15 generally applied for p>3000 psi, for 2000<p<3000 use equation 14.

Well test interpolation

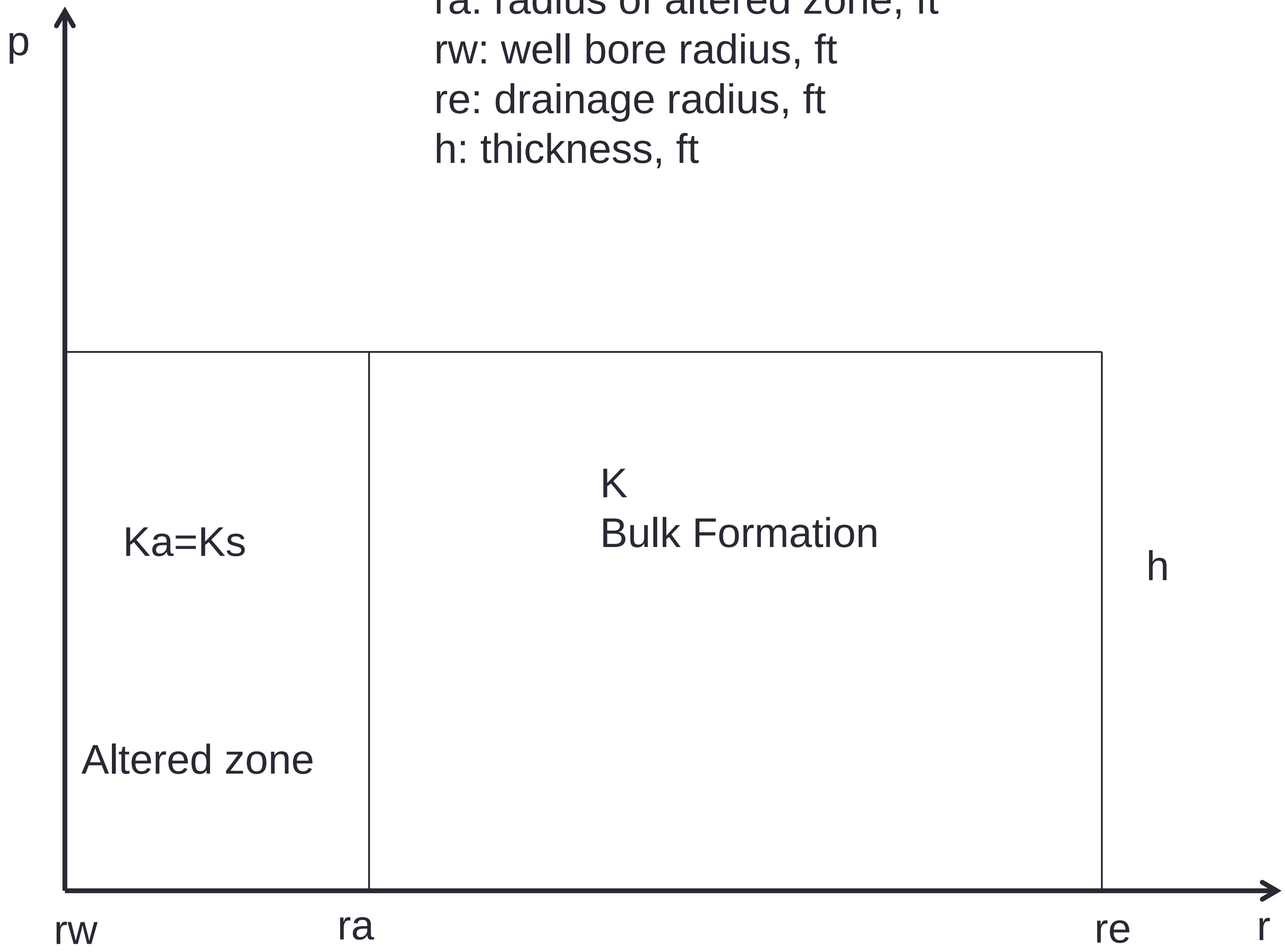
- Well tests in particular, build-up and fall off tests, are valuable tools for obtaining information about reservoir properties. Information available from these tests in clouds:

1. Amount of damage or stimulation
2. Bulk formation permeability
3. Static drainage area and reservoir pressure
4. Estimation of reservoir size and location of reservoir limits.

- Well test interpolation is usually based on a reservoir model with the following ideal properties:

1. The formation contains a single-phase liquid with constant viscosity, compressibility and formation volume factor.
2. The formation has constant porosity, and constant thickness (h) and is bounded above and below by impermeable barriers.
3. The reservoir has a zone of altered permeability, K_a of radial extent r_a surrounding the well and is otherwise of uniform permeability.

ra: radius of altered zone, ft
rw: well bore radius, ft
re: drainage radius, ft
h: thickness, ft



The Ei- function solution for unsteady-state flow

- To solve the equation describing flow of fluids in the above ideal reservoir it is necessary to introduce further restrictions, which will be removed later with the principle of superposition. These restrictions are:

1. The reservoir is infinite and contains only one well
2. The pressure in the reservoir is uniform prior to production
3. The well produce fluid at constant rate, q

- The equation which describes the relation between pressure, time and reservoir properties for the ideal situation is:
- $Pr=Pi+70.6\ (q\mu B/kh)\ Ei\ (-r^2/4\eta t)$, $r>r_a$
- $\eta=0.00633(k/\varphi\mu c)$
- For $x<0.02$ $Ei(-x) = \ln(1{,}78x)$
- Thus pressure at the sand face is described by the following equation for any time where $t>(r_w^2/0.08\eta)$
- $Pw=Pi + 70.6\ (q\mu B/kh)[\ln(0.445r_w^2/\eta t) - 2S]$
- $S= (k/k_a - 1)\ \ln\ (r_a/r_w)$

- For damage well, the skin factor is positive, for stimulation well, it is negative. It’s physical meaning is most clearly seen by relating it to the additional pressure drop incurred near the well to the existence of the zone of altered permeability:
- $\Delta p_s = 141.2\ (q\mu B/kh)\ s$
- Pr: pressure at a distance r from a well, psi
- Pi: initial reservoir pressure, psi
- q: flow rate, STB/day (the following sign convention is adopted for all rates, production rates are positive and injection rates are negative.
- μ: viscosity, cp
- K: permeability of bulk formation, md

- h: net sand thickness, ft
- r: radius of distance, ft
- t: time, days
- η: hydrolic diffusivity, ft^2/day
- c: compressibility, pis^{-1}
- rw: wellbore radius, ft
- Pw: bottom-hole sand face pressure, psi
- Pwf: flowing bottom hole pressure just before shut-in, psi

Principal of Superposition

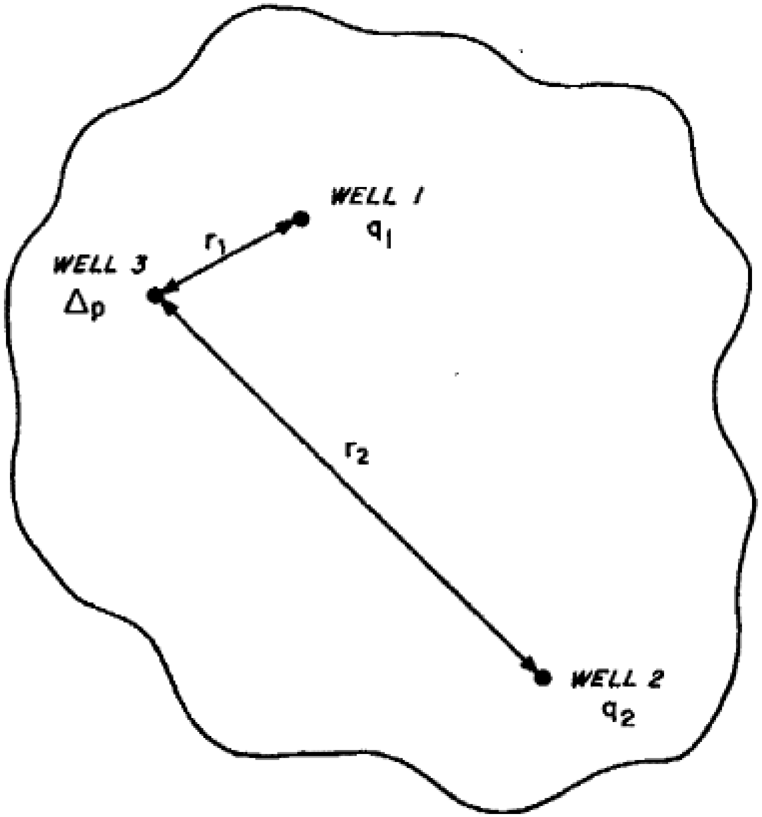


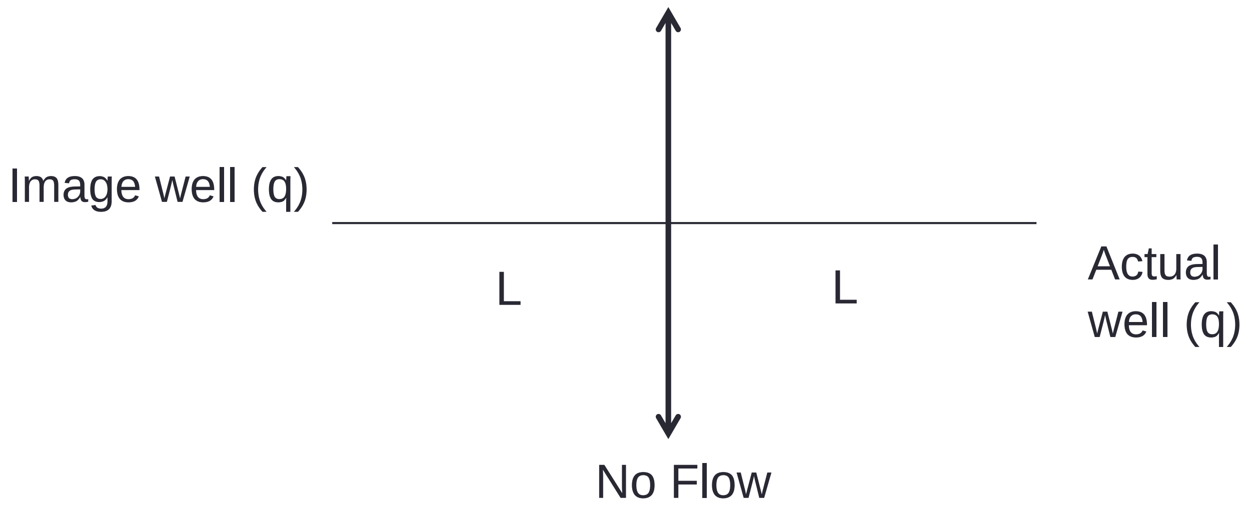
Fig. 2.18 Multiple-well infinite system for superposition explanation.

- The principle of superposition allows the Ei-function solution to be applied to multi-well reservoir, to bounded reservoir and to situation in which flow rate is variable.
- This principal states that the total pressure draw down at a point in a reservoir is a linear sum of the draw down to each well in the reservoir.
- Using the principle of superposition, the draw down at well A:
- $(Pw-Pi)_{\text{total at well A}} = (Pw-Pi)_{\text{due well A}} + (Pw-Pi)_{\text{due well B}} + (Pw-Pi)_{\text{due well C}}$

- If production in all wells begins at the same time:
- $P_w - P_i = 70.6\ (q_A \mu B/kh)[\ln(0.445\ r_{wa}^2/\eta t) - 2S_A] + 70.6\ (q_B \mu B/kh)\ Ei(-r_{AB}^2/4\eta t) + 70.6\ (q_C \mu B/kh)\ Ei(-r_{AC}^2/4\eta t)$
- q_A: rate of well A, STB/day
- q_B: rate of well B, STB/day
- q_C: rate of well C, STB/day
- r_{WA}: well bore radius of well A, ft
- r_{AB}: distance from well A to well B, ft
- r_{AC}: distance from well A to well C, ft
- S_A: Skin-factor of well A

Imaging (image – well)

- To simulate reservoir boundaries, the general technique is to add hypothetical wells to produce constant pressure or no-flow boundaries. This technique is called imaging



The sand – face pressure at the actual well at any time:

- $P_w - P_i = 70.6\,(q\mu B/kh)[\ln(0.445\, r_w^2/\eta t) - 2S] + 70.6\,(q\mu B/kh)\, Ei(-(2L)^2/4\eta t)$
- One of the most important uses of the superposition technique is to simulate a variable rate. The procedure is to superimpose the Ei-functions for a series of wells, each producing at constant rate, while adjusting the time at which each well begins production. For example, suppose we wish to simulate shutting in a well which has been producing at rate q from time t=0 to time t=t.

- We simulate this production by superimposing the pressure draw down due to producing a well at rate q from time t=0 to present (time $t+\Delta t$) and that due to producing a well at rate –q from time t to time $t+\Delta t$.
- The pressure draw down for this important case is given by:
- $P_w - P_i = 70.6\ q\mu B/kh[\ln(0.445 r_w^2/\eta(t+\Delta t)) - 2S] + 70.6\ (-q)\mu B/kh[\ln(0.445 r_w^2/\eta(t+\Delta t - t)) - 2S]$
- This equation simplifies to:
- $P_w - P_i = -162.6(q\mu B/kh) \log (t+ \Delta t/ \Delta t)$