NETool™ 5000.0.4.x Technical Manual

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Contents

PI Models

General

Inflow of oil, water and gas is modeled in NETool with productivity models. The most basic PI model is:

$$Q = PI \times \Delta P$$

A local productivity index (PI) is created based on upscaling as discussed later in this manual:

$$PI = M \times T$$

where M is mobility of a fluid phase and T is the transmissibility of the formation and flow geometry.

PI for a vertical well inside a homogenous reservoir can be represented by a simple formula that assumes radial inflow into the well. NETool uses this formulation:

$$PI = \frac{2\pi\, k_{eff} L}{\mu \left[\ln\left(r_e / r_w\right) + S\right]}$$

where:

k_{eff}	Effective upscaled permeability for flow perpendicular to the wellbore
L	Segment length
μ	Average fluid viscosity (see below)
r_e	Outer boundary radius
r_w	Wellbore radius
S	Skin

The definition of the average fluid is calculated from weighted averaging of flowing fluid phase reservoir volume fractions.

The inflow of the individual flowing phases of oil, water and gas is then calculated as follows:

$$q_o = PI \frac{1}{B_o} \frac{\frac{k_{ro}}{\mu_o}}{\frac{k_{ro}}{\mu_o} + \frac{k_{rg}}{\mu_g} + \frac{k_{rw}}{\mu_w}} \left(p_e - p_w\right) = \frac{2\pi\, k_{eff} L}{\ln\left(r_e / r_w\right) + S} \frac{k_{ro}}{B_o \mu_o} \left(p_e - p_w\right)$$

$$q_g = PI \ \frac{1}{B_g} \frac{\frac{k_{rg}}{\mu_g}}{\frac{k_{ro}}{\mu_o} + \frac{k_{rg}}{\mu_g} + \frac{k_{rw}}{\mu_w}} (p_e - p_w) = \frac{2\pi\, k_{eff} L}{\ln(r_e/r_w) + S} \frac{k_{rg}}{B_g \mu_g} \ (p_e - p_w)$$

$$q_w = PI \ \frac{1}{B_w} \frac{\frac{k_{rw}}{\mu_w}}{\frac{k_{ro}}{\mu_o} + \frac{k_{rg}}{\mu_g} + \frac{k_{rw}}{\mu_w}} (p_e - p_w) = \frac{2\pi\, k_{eff} L}{\ln(r_e/r_w) + S} \frac{k_{rw}}{B_w \mu_w} \ (p_e - p_w)$$

The most general formula for reservoir to well inflow in NETool is:

$$\frac{Q}{T \times M} + H \times Q^2 = \Omega \times (P_{res} - P_{well})$$

where:

M Mobility

T Transmissibility

H High velocity flow coefficient

Ω Condensate banking/gas break out adjustment coefficient

Radial Inflow

For vertical well a simple PI model for radial inflow is used:

$$PI = M \frac{2\pi\, k_h L}{\ln(r_e/r_w) + f + S}$$

where:

M Phase mobility

K_h Horizontal permeability

r_e Radial extent of the reservoir

r_w Wellbore radius

S Skin factor

L Segment length

and *f* is defined as follows:

0	If the Joshi (steady state) PI model is used together with "P at Re" (pressure is defined at the boundary r_e)
-0.5	If the Joshi (steady state) PI model is used together with "average P" (average reservoir pressure in the region)
-0.5	If the Babu and Odeh (semi-steady) model is used with circular region and "P at Re"

-0.75	If the Babu and Odeh (semi-steady) model is used with "average P" (average reservoir pressure in the region)
$0.5ln\left(\frac{4A_{dr}}{1.781C_a{r_w}^2}\right) - ln\left(\frac{r_e}{r_w}\right)$	If the Babu and Odeh (semi-steady) model is used with "Irregular region"; here A_{dr} is the drainage area and C_a is the Dietz shape factor.

Deviated Wells and Bedding Angles

In most real cases the wellbore penetrates the reservoir formation at an angle that is not parallel to the apparent dip of the formation. To properly calculate inflow, a 3D angle, Θ, between the wellbore and the formation bedding must be calculated.

NETool is using the following expression:

$$\Theta = \arccos\left(\frac{-\sin E\cos N\sin I\sin A - \cos E\sin N\sin I\cos A + \cos E\cos N\cos I}{1-\sin^2 E\sin^2 N}\right)$$

where E is bedding dip east, N is bedding dip north, I is well inclination, and A is well azimuth.

The Joshi PI Model

The Joshi model is based on a solution where the 3D flow problem is subdivided into two 2-D flow problems that then are added.

Figure 1 illustrates how the problem is divided into two 2D problems.

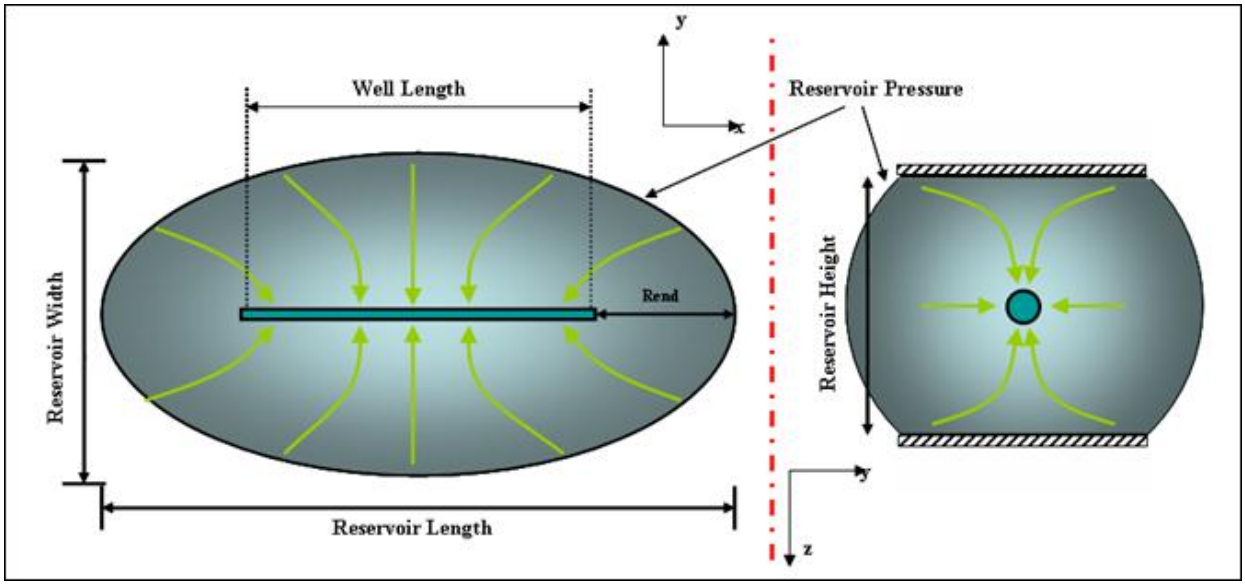


Figure 1. The Joshi PI model.

If pressure, p_0, is constant at the horizontal boundaries and at the ellipse in the plane of the well, the model gives flow rate as

$$Q = PI \cdot (p_0 - p_w)$$

where p_w is the pressure in the well and PI is a function of $K_{upscaled}$, h, a, K_h, r_w, and L. Here, $K_{upscaled} = \sqrt{K_h/K_v}$, L is the length of the well, and a is half the length of the ellipse.

As the model is based on a well located symmetrically in the reservoir where the constant pressure boundary forms an ellipse, the reservoir should have the same relationship between well length, reservoir length and reservoir width. These assumptions should been take into consideration when evaluating the calculated results.

Hence, it cannot be expected to model 3D, non-symmetrical flow problems correctly. For example, if the constant pressure boundary "moves away" from a well (maintaining the same pressure p_0) over time as the well is produced, it should be expected to result in lower flow rates. This is indeed the case if a is increased (with constant L). However, PI increases as a function of h up to a maximum and then decreases.

A heuristic evaluation of this model can be made as follows: if the well is fully penetrating the reservoir in the x-direction, and if the reservoir is infinite in the radial directions, a simple steady state analytical model for radial flow applies. In this case, there is a constant pressure on any cylinder surrounding the well.

Equivalent drainage radius for Joshi model can be found as:

$$r_{eh} = \sqrt{ba} = \sqrt{b\sqrt{b^2 + c^2}}$$

where b is half of value entered as reservoir width and c is half of well length.

The Babu and Odeh PI Model

This model also uses a rectangular box reservoir with a horizontal well parallel to the sides. There are three main differences between the Babu and Odeh model and the Joshi model:

- The model can handle cases where the well is not centered in the box reservoir.
- It is based on a semi-steady state assumption with no-flow boundaries giving flow rate as $Q = PI \cdot (p_{av} - p_w)$ where p_{av} is the average reservoir pressure at some point in time at which semi-steady state flow is obtained.
- It is a genuinely 3D analytical model.

Comparisons of the two models

Clearly, one has to use different pressures when comparing the Joshi and the Babu and Odeh models.

The pressure in the Joshi model should be taken at an estimated constant pressure boundary some distance away from the wellbore. If this distance is within the near well region (e.g. equal to the upscaling radius), the corresponding pressure will normally be lower than the remote reservoir pressure, since there will always be a draw down in the vicinity of the well. Instead of using the actual reservoir thickness (which should not have any influence on the productivity if pressure is maintained), one could for example use the equivalent h given above.

The reservoir pressure in the Babu and Odeh model is and average reservoir pressure at semi-steady state flow; hence, it is always lower than initial reservoir pressure. It is not obvious how to use the Babu and Odeh model if pressure in the reservoir is maintained. For example, if the well is located close to the boundaries, the Babu and Odeh model will predict low flow rates because of the influence from the no-flow boundaries. Therefore, if the Babu and Odeh model is used for a situation of pressure maintenance, one should minimize the effects of the boundaries, e.g. by choosing the well position central in the reservoir (but honoring the local reservoir properties at the actual well position). In any case, both models provide very rough estimates of flow rates.

Conclusion

The two PI models discussed above are very sensitive to what pressure is used and also to the parameters entered in the models, and they are not directly comparable since they are derived from different assumptions.

In general, if the overall well productivity is the main issue, it is strongly recommended to use NETool in combination with a reservoir simulator (or well test data) for calibration purposes. NETool, when used as a stand-alone simulator, is designed for inflow profile and pressure profile prediction for different completions and different local reservoir properties.

Advanced PI Models

NETool has an option that offers more advanced PI modeling than the basic $Q = PI \times \Delta P$ model.

PI Multipliers

NETool includes two configurable multipliers that can be used to adjust the productivity index to match production or injection rates. The two multipliers are the global Well PI multiplier, found in **Global Settings→Inflow**, and the per-segment transmissibility multipliers, found in the Well Segments & Completions settings in the **Reservoir Parameters→Transmissibility** folder. The per-segment transmissibility multipliers are available only when the "Transmissibility from" parameter is set to "From PI model/permeability".

Specifically, the PI multipliers adjust the PI model as follows:

$$PI = C_{well} \cdot C_{segment} \cdot T \cdot M$$

where C_{well} is the global well PI multiplier and $C_{segment}$ is the per-segment transmissibility multiplier. The global well PI multiplier can be calibrated to a well performance target by using the "Calibrate well PI multiplier" feature in **Global Settings→Inflow**.

Oil Producers and Wet Gas Producers

A significant pressure drop in the near well region can significantly alter well productivity due to relative permeability effects from condensate banking or gas break out in that region.

NETool has a model which calculates reduction coefficient Ω which is a multiplication factor for the productivity index.

The model uses the following assumptions:

The volume phase flow rates are adequately described by the Darcy law and the relative permeabilities are known functions of saturations

Fluid densities and viscosities are known functions of pressure

Saturations are in steady-state condition

Gas Producers

NETool uses a model equivalent to the backpressure equation: $q_g = C\left(p_R^2 - p_{wf}^2\right)^n$

Injectivity Index for single phase injection

Injectivity Index is similar to Productivity index: II = Q/(Pres-Pwell), where Q is the well-reservoir flow.

Injectivity Index in Regular Mode

Injectivity index is calculated as $II = \frac{T}{\mu(P_{res})B(P_{res})}$,

Where μ is fluid viscosity, B is formation volume factor, and T is segment transmissibility.

Injectivity Index in Advanced Mode

A radial near wellbore model is used: Area around the wellbore is splitted into concentrical rings. For each ring μ and B are calculated:

$$II = \frac{1}{N}\sum_{n=1}^{N}\frac{T}{\mu(P^n{}_{res})B(P^n{}_{res})}.$$

If PVT table is such that μ =const and PB=zT=const,

$$II = \frac{T(P^{res} + P^{well})}{2\mu P^{well}}$$

Mobility

Phase mobilties control how the fluid properties and fluid-rock interactions affect production or injection. Mobility is used to calculate the flow of each phase from the reservoir into the wellbore, as follows:

$$Q_i = M_i \cdot T \cdot (P_{reservoir} - P_{annulus})$$

where *Qi* is the phase flow rate and *Mi* is the phase mobility, $M_i = k_{r,i}/\mu_i$.

Mobility can be defined in three different ways in NETool: from relative permeability, from phase flowing fractions, and manually.

Parameters:

S_o : *Oil saturation* (*Manual entry or from Grid Block*)

S_w : *Water saturation* (*Manual entry or from Grid Block*)

S_g : *Gas saturation* (*Manual entry or from Grid Block*)

$k_{ro}(S_o, S_{otherphases})$: *Oil relative permeability* (*Manual entry or from relative permeability table / correlation*)

$k_{rw}(S_w, S_{otherphases})$: *Water relative permeability* (*Manual entry or from relative permeability table / correlation*)

$k_{rg}(S_g, S_{otherphases})$: *Gas relative permeability* (*Manual entry or from relative permeability table / correlation*)

P : Re*servoir pressure* (*Manual entry or from Grid Block*)

We determine individual phase mobilities from i) saturations and ii) relative permeabilities as:

$$M_o = \frac{k_{ro}(S_o, S_{phase})}{\mu_o(P)} \qquad M_w = \frac{k_{rw}(S_w, S_{phase})}{\mu_w(P)} \qquad M_g = \frac{k_{rg}(S_g, S_{phase})}{\mu_g(P)}$$

total mobility is:

$$M_{tot} = M_o + M_w + M_g$$

injector mobility:

$$M_{injector} = M_{tot}$$

flowing fractions of each phase are:

$$\alpha_o = \frac{M_o}{M_{tot}} \qquad \alpha_w = \frac{M_w}{M_{tot}} \qquad \alpha_g = \frac{M_g}{M_{tot}}$$

mobility weighted mixed viscosity of the reservoir´s flowing fluids is:

$$\mu_{mix} = \alpha_o \mu_o(P) + \alpha_w \mu_w(P) + \alpha_g \mu_g(P)$$

Saturation & Relative Permeability

Relative permeability is fundamentally a function of current saturations and the saturation history (hysteresis). Saturations are therefore used to define relative permeability values.

Five alternative main options are available to define relative permeability in NETool:

1. From RelPerm Table in Eclipse format option or From Eclipse INIT file option - relative permeability is looked up from the Relative Permeability Tables based on saturation. In addition 4 models are available to calculate three-phase oil relative permeability.

2. From Relperm table – presents relative permeabilities in tables. The number of tables and table types are defined by the Two-phase Oil Relperms dropdown menu. In addition 4 models are available to calculate three-phase oil relative permeability.

3. From Wyllie's CS,OL corr. - Wyllie's correlations for cemented sandstone, oolitic limestone:

$$S_o^{'} = S_o / 1 - S_{wc}$$
$$S_g^{'} = S_g / 1 - S_{wc}$$
$$S_w^{'} = S_w - S_{wc} / 1 - S_{wc}$$
$$k_{ro} = (S_o^{'})^3 \ (2S_w^{'} + S_o^{'})$$
$$k_{rg} = (S_g^{'})^3 \ (2 - S_g^{'})$$
$$k_{rw} = (S_w^{'})^4$$

4. From Wyllie's US,WS corr. - Wyllie's correlations for unconsolidated sand, well sorted:

$$S_o^{'} = S_o / 1 - S_{wc}$$
$$S_g^{'} = S_g / 1 - S_{wc}$$
$$S_w^{'} = S_w - S_{wc} / 1 - S_{wc}$$
$$k_{ro} = (S_o^{'})^3$$
$$k_{rg} = (S_g^{'})^3$$
$$k_{rw} = (S_w^{'})^3$$

Fractional Flow

Mobilities can also be defined in NETool by providing Flowing Fractions as downhole volume fractions of fluids entering the well. Gas and water fractions are entered, and the remainder is calculated as oil.

Mobilities will be back-calculated to match the given flowing fractions:

$$\lambda_o = \alpha_o / (\alpha_o \mu_o + \alpha_g \mu_g + \alpha_w \mu_w)$$
$$\lambda_g = \alpha_g / (\alpha_o \mu_o + \alpha_g \mu_g + \alpha_w \mu_w)$$
$$\lambda_w = \alpha_w / (\alpha_o \mu_o + \alpha_g \mu_g + \alpha_w \mu_w)$$

This back-calculation implicitly assumes that kro + krg + krw = 1. Viscosities (μ) are obtained from the PVT modeling.

Flowing Fractions can be suitable when i) the downhole volume fractions of fluids entering the well is known (such as results from a PLT log), ii) when relative permeability data is unavailable or iii) you just want to run some quick screening sensitivities.

Manual Mobility

Manual - the user enters manually the Mobility for each phase. This option is most useful with reservoir simulator mobilities available.

The manual mobility option was originally included for the dynamic linking with a reservoir simulator.

Manually entered mobilities force viscosities defined in the PVT table not to be used for reservoir flow calculations as mobilities will be taken "as is" from this input.

Transmissibility Definition

Transmissibility controls the inflow calculation from the reservoir into the well:

Flow rate = Mobility * Transmissibility * (Reservoir pressure – Well pressure).

Transmissibility reflects reservoir rock properties (permeability), well geometry and reservoir drainage geometry and conditions. NETool offers three alternatives to define transmissibility:

1. From PI model/permeability—uses the PI model to calculate the flow from reservoir to well based on permeability. This is the default method.
2. Manual T_A & T_B—A and B factors of the transmissibility equation are entered manually, where the transmissibility equation is give by $T = A/(B + S)$, where S is the skin factor.
3. Manual—transmissibility is entered directly.When transmissibility is entered directly, it is assumbed that skin factor is included in this value, and skin factor input and skin calculation will be disabled.

Injection Mobility

Netool has the following two methods for determining mobility of the injected fluid in the formation:

1. **Long Term**

   This model assumes injector has been operational for a long time and formation is filled up with the injected component. Mobility equals the mobility of the component being injected.

Gas Injector	Water Injector
$\lambda_g = 1/\mu_g$ $Q_g = \lambda_g \times T \times \Delta P$	$\lambda_w = 1/\mu_w$ $Q_w = \lambda_w \times T \times \Delta P$

2. **Short Term**

This model assumes injection process is starting and formation has its original fluids in place; the injected phase has not penetrated the near-wellbore area to any great extent. The injected fluid is displacing all movable phases according to their calculated mobility. The effective mobility equals to the sum of mobilities of phase components.

Gas Injector	**Water Injector**
$\lambda_o = k_{ro}/\mu_o, \lambda_g = k_{ro}/\mu_g, \lambda_w = k_{ro}/\mu_w$	
$Q_g = (\lambda_o + \lambda_g + \lambda_w) \times T \times \Delta P$	$Q_w = (\lambda_o + \lambda_g + \lambda_w) \times T \times \Delta P$

PVT

Multiple Bubble Point Oil

Oil Properties for Undersaturated Region

The oil properties for the undersaturated region are calculated as follows:

$$B_o = B_{o,sat}(P_{bp}) \cdot e^{-c_o \cdot \Delta P} \approx \frac{B_{o,sat}(P_{bp})}{1 + c_o \cdot \Delta P}$$

$$\mu_o = \mu_{o,sat}(P_{bp}) \ \ (1 + Vis\cos ibility_{\ oil} \ \Delta P)$$

where:

$$\Delta P = P - P_{bp}$$

$P_{bp,}$ bubble point pressure, is found by interpolating in the PVT data by using the Rs values and pressures.

Example

The example illustrates the PVT multiple bubble point modeling. The basic PVT data is given in the PVT table shown below. The aim is to determine Bo and oil viscosity when Rs=27 and P=300.

Oil PVT with Multiple Bubble Points ☑

P	Rs	Bo,sat	Co,u-sat	Vo,sat	Cvo,u-sat	Bg	Vg
[Bar]	[Sm³/Sm³]	[Rm³/Sm³]	[1/Bar]	[cP]	[1/Bar]	[Rm³/Sm³]	[cP]
1.0	1.0	1.1	0.02	0.85	9.07E-4	1.12	0.0065
10.0	10.0	1.2	0.0020	0.84	9.08000E-4	0.112	0.0077
100.0	20.0	1.3	3.5E-4	0.65	9.34E-4	0.0112	0.034
200.0	30.0	1.4	2.3E-4	0.47	9.87E-4	0.0056	0.109
300.0	40.0	1.5	2.0E-4	0.35	0.0010	0.0037	0.229

Figure 2. Example of a Multi Bubble Point PVT Table

The following algorithm is used by NETool :

1. Find the two closest R_s to R_s=27. It is rows #3 (R_s=20) and #4 (R_s=30)
2. Using under-saturated compressibility, extrapolate points (3) and (4) to P = 300bar to get points A and B.
3. Interpolate in R_s between points A and B to get B_o.

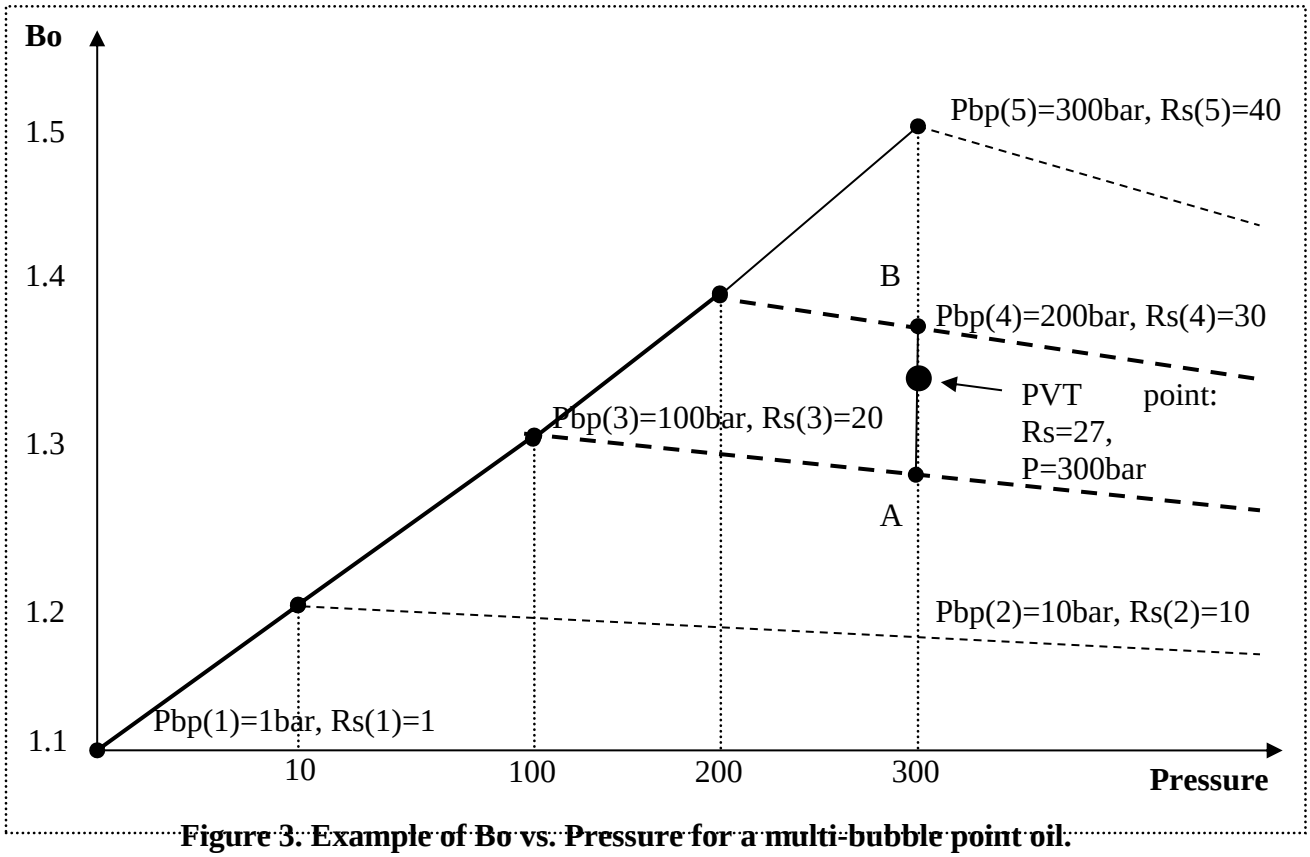


Figure 3. Example of Bo vs. Pressure for a multi-bubble point oil.

In other words, NETool uses the saturated R_s, B_o and μ_o parameters, and assumes that μ_o and $1/B_o$ are linear with pressure for the undersaturated region, in order to calculate interpolated PVT properties for the undersaturated oil.

Wet Gas with Multiple Dew Points

Gas Properties for Undersaturated Region

The gas properties for the undersaturated region are calculated as follows:

NETool assumes that the expansion factor $E_g \equiv 1/B_g$ and viscosity V_g of undersaturated wet gas are linear with R_v:

$$E_g(R_v) = E_{g,dry} + \frac{R_v}{R_{v,sat}}\left(E_{g,wet} - E_{g,dry}\right)$$

$$\mu_g(R_v) = \mu_{g,dry} + \frac{R_v}{R_{v,sat}}\left(\mu_{g,wet} - \mu_{g,dry}\right)$$

R_v values are input directly and $R_{v,sat}$ is calculated interpolating in saturated $R_{v,sat}$ data as function of pressures.

Water PVT Properties

NETool uses the following formulas for water property calculations:

$$B_w = \frac{B_w(P_{ref})}{1 + c_w (P - P_{ref})}$$

$$\mu_w = \frac{\mu(P_{ref})}{1 + viscosibility_{water} (P - P_{ref})}$$

$$B_w = -\frac{1}{dB_w}\frac{dB_w}{dP}$$

$$viscosibility_{water} = \frac{1}{\mu_w}\frac{d\mu_w}{dP}$$

PVT Correlations

Table 1 shows the simple industry-standard PVT correlations available in NETool for generation of PVT data based on limited PVT information.

Table 1. PVT correlations

PVT parameter	Correlation
Solution Gas Oil Ratio	Standing
Bubble Point pressure	Standing
Oil Formation Volume Factor ($P > P_{bp}$)	Standing
Oil Formation Volume Factor ($P < P_{bp}$)	Standing
Oil compressibility	Standing
Dead oil viscosity	Glasø
Saturated Oil Viscosity	Standing
Undersaturated Oil Viscosity	Standing
Pseudo Critical Temperature	Sutton
Pseudo Critical Pressure	Sutton
Gas Viscosity	Carr et al., Dempsey, Standing
Z-factor	Hall and Yarborough
Gas Formation Volume Factor	Equation of State
Water compressibility	Rowe and Chou
Water Viscosity	Kestin

PVT parameter	Correlation
Water Density	Rowe-Chou
Water Formation Volume Factor	Rowe-Chou

Three Phase Oil Relative Permeability

Eclipse - Default K_{ro} Model

This is the default method used by Sclumberger's Eclipse reservoir simulator

This method is the same method as used by in Eclipse as the default method. Gas and water are assumed to be completely segregated. Oil relative permeability is calculated by a simple averaging method:

$$k_{ro} = \frac{S_g \cdot k_{rog} + (S_w - S_{wco}) \cdot k_{row}}{S_g + S_w - S_{wco}},$$

where S_g is current gas saturation; S_w is current water saturation; S_{wco} is connate water saturation; k_{rog} is oil relative permeability in the presence of oil, gas and connate water only; and k_{row} is oil relative permeability in the presence of oil and water only.

If '*Two-phase oil relperms tabulated against S_g and S_w*' option is chosen or if Eclipse-format relperms are given by SWOF+SGOF (or SWOF+SLGOF) keywords:

k_{rog} is looked up at $S_g' = S_g + S_w - S_{wco}$
k_{row} is looked up at $S_w' = S_w + S_g$

If '*Two-phase oil relperms tabulated against S_o*' option is chosen or if Eclipse-format relperms are given SOF3+SGFN+SWFN keywords:
k_{rog} and k_{row} are looked up at $S_o' = 1 - S_w - S_g$

Stone's first k_{ro} model
This method is the method used in the Eclipse as Stone's first model (modified).

$$k_{ro} = k_{rocw} \cdot SS_o \cdot F_w \cdot F_g$$

where:
k_{rocw} is the value of the oil relative permeability in the presence of connate water only
$SS_o = (S_o - S_{om}) / (1 - S_{wco} - S_{om})$ when $S_o > S_{om}$
$SS_w = (S_w - S_{wco}) / (1 - S_{wco} - S_{om})$ when $S_w > S_{wco}$
$SS_g = S_g / (1 - S_{wco} - S_{om})$
$F_w = k_{row} / k_{rocw} / (1 - SS_w)$
$F_g = k_{rog} / k_{rocw} / (1 - SS_g)$

In these formulas:
S_o, S_w and S_g denote block averaged values for the oil, water and gas saturations in a grid cell.
S_{wco} — connate water saturation

k_{rog} — oil relative permeability in the presence of oil, gas and connate water only.

k_{row} — oil relative permeability in the presence of oil and water only.

k_{rocw} — oil relative permeability in the presence of connate water only.

S_{om} — minimum residual oil saturation which is taken to be the minimum of the critical oil-to-water saturation and the critical oil-to-gas saturation: $S_{om} = \min(S_{org}, S_{orw})$.

If '*Two-phase oil relperms tabulated against S_g and S_w*' option is chosen or if Eclipse-format relperms are given by SWOF+SGOF (or SWOF+SLGOF) keywords:

k_{rog} is looked up at the current gas saturation S_g

k_{row} is looked up at the current water saturation S_w

If '*Two-phase oil relperms tabulated against S_o*' option is chosen or if Eclipse-format relperms are given SOF3+SGFN+SWFN keywords:

k_{rog} is looked up at $S_o' = S_o+S_w-S_{wco} = 1-S_g-S_{wco}$

k_{row} is looked up at $S_o' = 1-S_w = S_o+S_g$.

Stone's first K_{ro} model modified by Fayers and Matthews

Fayers and Matthews (*Fayers, F. J., Matthews, J. D. 1989, Extension of Stone's Method I and conditions for real characteristics in three-phase flow, SPE Reservoir Eng. 4, 437-445*) proposed to calculate S_{om} instead as:

$$S_{om} = S_{orw} + S_g \cdot (S_{org} - S_{orw}) / (1 - S_{wco} - S_{org})$$

where:

S_{org} — residual oil saturation when displaced by gas

S_{orw} — residual oil saturation when displaced by water.

Stone's 2nd model

This method is the method used in Eclipse as Stone's second model (modified).

The relative permeability to oil is then calculated as

$$k_{ro} = k_{rocw} \cdot [(k_{row}/k_{rocw} + k_{rw}) \cdot (k_{rog}/k_{rocw} + k_{rg}) - k_{rw} - k_{rg}]$$

Where :

k_{row} — oil relative permeability in the presence of oil and water only.

k_{rog} — oil relative permeability in the presence of oil, gas and connate water only.

k_{rocw} — oil relative permeability in the presence of oil and connate water only.

Note: *When this equation causes calculation of negative k_{ro} it is set to zero.*

If '*Two-phase oil relperms tabulated against S_g and S_w*' option is chosen or if Eclipse-format relperms are given by SWOF+SGOF (or SWOF+SLGOF) keywords:

k_{rog} is looked up at the current gas saturation S_g
k_{row} is looked up at the current water saturation S_w

If '*Two-phase oil relperms tabulated against S_o*' option is chosen or if Eclipse-format relperms are given SOF3+SGFN+SWFN keywords:

k_{rog} is looked up at $S_o' = S_o+S_w-S_{wco} = 1-S_g-S_{wco}$
k_{row} is looked up at $S_o' = 1-S_w = S_o+S_g$.

This method is the same method as used by in Eclipse as the default method; gas and water are assumed to be completely segregated.

Oil relative permeability is calculated by a simple averaging method:

$$k_{ro} = [\ S_g \cdot k_{rog} + (S_w - S_{wc}) \cdot k_{row}\ ] / [\ S_g + S_w - S_{wc}\ ]$$

Where:
S_g—current gas saturation
S_w—current water saturation
S_{wc}—connate water saturation
k_{row}—oil relative permeability in the presence of oil and water only.
k_{rog}—oil relative permeability in the presence of oil, gas and connate water only.

SWOF+SGOF or SWOF+SLGOF keywords:
S_{wc} is the water saturation value in the first SWOF row
k_{row} is taken from SWOF table at $S_w' = S_w + S_g$
k_{rog} is taken from SGOF (SLGOF) table at $S_g' = S_g + S_w - S_{wc}$
SOF3+SGFN+SWFN keywords:
S_{wc} is the water saturation value in the first SWFN row
k_{row} and k_{rog} are taken from SOF3 table at $S_o = 1- S_w - S_g$

Relative Permeability End-point Scaling

Saturation End-Points ("Horizontal Scaling")

Two End-Points Scaling

The following table summarizes two saturation end-points used for each phase relative permeability:

Curve	End-points
k_{rog}	S_{org} and $1-S_{wco}$
k_{row}	S_{orw} and $1-S_{wco}$
k_{rg}	S_{gcr} and S_{gmax}
k_{rw}	S_{wcr} and S_{wmax}

The relative permeability curves are linearly scaled to preserve relative permeabilities at saturation end-points. Below are detailed formulas:

Oil-in-gas relative permeability $k_{rog}(S_o)$ is evaluated in the input saturation table at the new value of oil saturation

$$S_o^{'} = \bar{S}_{org} + (S_o - S_{org}) \cdot (1 - \bar{S}_{wco} - \bar{S}_{org}) / (1 - S_{wco} - S_{org})$$

Where:

S_o — oil saturation

$\bar{S}_{org}$, $\bar{S}_{wco}$ — unscaled critical oil-in-gas saturation and connate water saturations defined by the relative permeability table

S_{org} , S_{wco} — actual critical oil-in-gas saturation and connate water saturation defined here.

Oil-in-water relative permeability $k_{row}(S_o)$ is evaluated in the input saturation table at the new value of oil saturation

$$S_o^{'} = \bar{S}_{orw} + (S_o - S_{orw}) \cdot (1 - \bar{S}_{wco} - \bar{S}_{orw}) / (1 - S_{wco} - S_{orw})$$

Where:

S_o—oil saturation

$\bar{S}_{orw}$, $\bar{S}_{wco}$ —unscaled critical oil-in-water saturation and connate water saturations defined by the relative permeability table

S_{orw} , S_{wco}—actual critical oil-in-water saturation and connate water saturation defined here.

Gas relative permeability $k_{rg}(S_g)$ is evaluated in the input saturation table at the new value of gas saturation

$$S_g^{'} = \bar{S}_{gcr} + (S_g - S_{gcr}) \cdot (\bar{S}_{g\max} - \bar{S}_{gcr}) / (S_{g\max} - S_{gcr})$$

Where:

S_g —gas saturation

$\bar{S}_{gcr}$ —unscaled critical gas saturation defined by the relative permeability table

$\bar{S}_{g\max}$ —unscaled maximum gas saturation, $\bar{S}_{g\max} = 1 - \bar{S}_{wco}$, where $\bar{S}_{wco}$ —unscaled connate water saturation defined by the relative permeability table

S_{gcr} —actual critical gas saturation defined by saturation end-points

$S_{g\max}$ —actual maximum gas saturation, $S_{g\max} = 1 - S_{wco}$, where S_{wco} —connate water saturations defined by saturation end-points.

Water relative permeability $k_{rw}(S_w)$ is evaluated in the input saturation table at the new value of water saturation

$$S_w^{'} = \bar{S}_{wcr} + (S_w - S_{wcr}) \cdot (\bar{S}_{w\max} - \bar{S}_{wcr}) / (S_{w\max} - S_{wcr})$$

Where:

S_w—water saturation

$\bar{S}_{wcr}$ —unscaled critical saturation defined by the relative permeability table

$\bar{S}_{w\max}$ —unscaled maximum water saturation, $\bar{S}_{w\max} = 1$

S_{wcr} —actual critical water saturation defined by saturation end-points

$S_{w\max}$ —actual maximum water saturation, $S_{w\max} = 1$.

Three End-Points Scaling

The following table summarizes three saturation end-points used for each phase relative permeability:

Curve	End-points
k_{rog}	S_{org}, $(1-S_{gcr}-S_{wco})$ and $1-S_{wco}$
k_{row}	S_{orw}, $(1-S_{wcr})$ and $1-S_{wco}$
k_{rg}	S_{gcr}, $(1-S_{org})$ and S_{gmax}
k_{rw}	S_{wcr}, $(1-S_{orw})$ and S_{wmax}

The relative permeability curves are linearly scaled to preserve relative permeabilities at saturation end-points. Below are detailed formulas.

Oil-in-gas relative permeability k_{rog} is evaluated in the input saturation table at the new value of oil saturation $S_o^{'}$ scaled from oil saturation S_o. If S_r and $\bar{S}_r$ are actual and unscaled displacing critical saturations,

$$S_r = 1 - S_{gcr} - S_{wco}$$

$$\bar{S}_r = 1 - \bar{S}_{gcr} - \bar{S}_{wco}$$

the two cases are:

1. $S_{org} \le S_o \le S_r$

$$S_o^{'} = \bar{S}_{org} + (S_o - S_{org}) \cdot (\bar{S}_r - \bar{S}_{org}) / (S_r - S_{org})$$

2. $S_r \le S_o \le 1 - S_{wco}$

$$S_o^{'} = \bar{S}_r + (S_o - S_r) \cdot (1 - \bar{S}_{wco} - \bar{S}_r) / (1 - S_{wco} - S_r)$$

Where:

S_o — oil saturation

$\bar{S}_{gcr}$, $\bar{S}_{org}$ and $\bar{S}_{wco}$ — unscaled critical gas, critical oil-in-gas and connate water saturations defined by the relative permeability table

S_{gcr}, S_{org} and S_{wco} — actual critical gas, critical oil-in-gas and connate water saturation defined by saturation end-points.

Oil-in-water relative permeability k_{row} is evaluated in the input saturation table at the new value of oil saturation $S_o^{'}$ scaled from oil saturation S_o. If S_r and $\bar{S}_r$ are scaled and unscaled displacing critical saturations,

$S_r = 1 - S_{wcr}$

$\bar{S}_r = 1 - \bar{S}_{wcr}$

the two cases are:

1. $S_{orw} \le S_o \le S_r$

$$S_o^{'} = \bar{S}_{orw} + (S_o - S_{orw}) \cdot (\bar{S}_r - \bar{S}_{orw}) / (S_r - S_{orw})$$

2. $S_r \le S_o \le 1 - S_{wco}$

$$S_o^{'} = \bar{S}_r + (S_o - S_r) \cdot (1 - \bar{S}_{wco} - \bar{S}_r) / (1 - S_{wco} - S_r)$$

Where:

S_o — oil saturation

$\bar{S}_{wcr}$, $\bar{S}_{orw}$ and $\bar{S}_{wco}$ — unscaled critical water, critical oil-in-water and connate water saturations defined by the relative permeability table

S_{wcr}, S_{orw} and S_{wco} — actual critical water, critical oil-in-water saturation and connate water saturation defined by saturation end-points.

Gas relative permeability k_{rg} is evaluated in the input saturation table at the new value of gas saturation $S_g^{'}$ scaled from gas saturation S_g. If S_r and $\bar{S}_r$ are scaled and unscaled displacing critical saturations,

$$S_r = 1 - S_{org}$$

$$\bar{S}_r = 1 - \bar{S}_{org}$$

the two cases are:

1. $S_{gcr} \le S_g \le S_r$

$$S_g^{'} = \bar{S}_{gcr} + (S_g - S_{gcr}) \cdot (\bar{S}_r - \bar{S}_{gcr}) / (S_r - S_{gcr})$$

2. $S_r \le S_g \le S_{g\max}$

$$S_g^{'} = \bar{S}_r + (S_g - S_r) \cdot (\bar{S}_{g\max} - \bar{S}_r) / (S_{g\max} - S_r)$$

Where:

S_g — gas saturation

$\bar{S}_{org}$ and $\bar{S}_{gcr}$ — unscaled critical oil-in-gas and critical gas saturations defined by the relative permeability table,

$\bar{S}_{g\max}$ — unscaled maximum gas saturation, $\bar{S}_{g\max} = 1 - \bar{S}_{wco}$, where $\bar{S}_{wco}$ — unscaled connate water saturation defined by the relative permeability table

S_{gcr} and S_{gcr} — actual critical oil-in-gas and critical gas saturations defined by saturation end-points

$S_{g\max}$ — actual maximum gas saturation, $S_{g\max} = 1 - S_{wco}$, where S_{wco} — connate water saturations defined by saturation end-points.

Water relative permeability k_{rw} is evaluated in the input saturation table at the new value of water saturation $S_w^{'}$ scaled from water saturation, S_w. If S_r and $\bar{S}_r$ are scaled and unscaled displacing critical saturations,

$$S_r = 1 - S_{orw}$$

$\bar{S}_r = 1 - \bar{S}_{orw}$

the two cases are:

1. $S_{wcr} \le S_w \le S_r$

   $S_w^{'} = \bar{S}_{wcr} + (S_w - S_{wcr}) \cdot (\bar{S}_r - \bar{S}_{wcr}) / (S_r - S_{wcr})$

2. $S_r \le S_w \le S_{w\max}$

   $S_w^{'} = \bar{S}_r + (S_w - S_r) \cdot (\bar{S}_{w\max} - \bar{S}_r) / (S_{w\max} - S_r)$

Where:

S_w —water saturation

$\bar{S}_{orw}$ and $\bar{S}_{wcr}$ —unscaled critical oil-in-water and critical water saturations defined by the relative permeability table

$\bar{S}_{w\max}$ —unscaled maximum water saturation, $\bar{S}_{w\max} = 1$

S_{orw} and S_{wcr} —actual critical oil-in-water and critical water saturations defined by saturation end-points

$S_{w\max}$ —actual maximum water saturation, $S_{w\max} = 1$.

Scaling of the Relative Permeability Values: "Vertical Scaling"

"Vertical scaling" can be applied to the relative permeability values calculated from the appropriate relperm table after the scaled saturation end points have been accounted for. The scaling is as follows:

$$k_{ro} \to k_{ro}\left(k_{ro\_\max} / \bar{k}_{ro\_\max}\right)$$
$$k_{rg} \to k_{rg}\left(k_{rg\_\max} / \bar{k}_{rg\_\max}\right)$$
$$k_{rw} \to k_{rw}\left(k_{rw\_\max} / \bar{k}_{rw\_\max}\right)$$

Where:

$\bar{k}_{ro\_\max}, \bar{k}_{rg\_\max}, \bar{k}_{rw\_\max}$ —unscaled maximum values of relative permeabilities defined by the relative permeability table.

$k_{ro\_\max}, k_{rg\_\max}, k_{rw\_\max}$ —actual values of maximum relative permeabilities defined here.

Summary of Inputs

NETool Input	Description	Equivalent Eclipse Keyword	Unscaled Value	End-Point for
S_{org}	Critical oil-in-gas saturation	SOGCR	The largest S_o in the table for which $k_{rog}=0$ (If k_{rog} is tabulated against S_g then this is the maximum value of $(1-S_g)$ for which $k_{rog}=0$)	k_{rog}
S_{orw}	Critical oil-in-water saturation	SOWCR	The largest S_o in the table for which $k_{row}=0$ (If k_{row} is tabulated against S_w then this is the maximum value of $(1-S_w)$ for which $k_{row}=0$)	k_{row}
S_{gcr}	Critical gas saturation	SGCR	The largest S_g in the table for which $k_{rg}=0$	k_{rg}
S_{gmax}	Maximum gas saturation	SGU	The largest S_g in the table	k_{rg}
S_{wco}	Connate water saturation	SWL	The smallest S_w in the table (In models with no water phase, the unscaled value of connate water saturation is $1-S_{o\_largest}$ or $1-S_{g\_largest}$ depending on the phase mode and the table type)	k_{rog} , k_{row}. (Also assumed to be the true connate water saturation for all other purposes.)
S_{wcr}	Critical water saturation	SWCR	The largest S_w in the table for which $k_{rw}=0$	k_{rw}
S_{wmax}	Maximum water saturation	SWU	The largest S_w in the table	k_{rw}
"Vertical Scaling"				
k_{ro_max}	Maximum value of oil relative permeability i.e. oil relative permeability in a system of oil and connate water	KRO	The largest k_{rog} or k_{row} in the table (in three-phase mode the two values must always be equal)	k_{rog} , k_{row}
k_{rg_max}	Maximum value of gas relative permeability i.e. gas relative permeability in a system of oil and	KRG	The largest k_{rg} in the table	k_{rg}

NETool Input	Description	Equivalent Eclipse Keyword	Unscaled Value	End-Point for
	connate water			
k_{rw_max}	Maximum value of water relative permeability	KRW	The largest k_{rw} in the table	k_{rw}

Permeability Upscaling

This section covers permeability upscaling from reservoir grid permeabilities.

The upscaled permeability K_{ups} for a radial flow into a cylindrical area is given by:

$$K_{ups} = \frac{\ln \frac{r_o}{r_w}}{\int_{r_w}^{r_o} \frac{dr}{K(r)r}}$$

where r_w is an equivalent wellbore radius and r_o is the upscaling radius.

Before upscaling is performed on the reservoir grid it is first exposed to stretching in the vertical direction: $z' = z / \sqrt{Kv / Kh}$. This stretching converts an elliptical inflow area into a circular one.

NETool calculates how radius r intersects gridblocks and establishes several radial sub segments on which the reservoir grid permeability is constant. Same is done for angular and axial directions. The final value for K_{ups} is calculated as a normalized inversed sum of permeabilities in surrounding grid blocks.

The vertical and angular resolution of the calculation can be controlled by the user ("Upscaling MD steps" and "N angular steps" in **Segment settings→Reservoir parameters→Transmissibilities**).

This model assumes that all inflow lines are perpendicular to the well and reservoir pressure at distance $r=r_0$ is identical in all directions from the well.

Skin

Non-Darcy Skin

The non-Darcy skin model is important when high flow rates into the well occur. This model is second order in flow rate. The skin model equation is

$$\Delta P = \frac{Q}{T \cdot \lambda} + H \cdot Q^2,$$

where Q is influx per unit well length (at downhole conditions), T is transmissibility per unit well length, λ is phase mobility, ΔP is drawdown, and H is the second order influx coefficient. The last term, $H \cdot Q^2$, expresses the non-Darcy behavior of the flow.

Conventionally, this second order inflow equation is equivalently written in terms of D-factor and non-Darcy skin:

$$Q = \frac{A}{B + S_{Darcy} + D \cdot Q} \lambda \cdot \Delta P,$$

where A and B define transmissibility, $T = A/\left(B + S_{Darcy}\right)$, and $D \cdot Q$ is non-Darcy skin.

Skin D-factor is related to H as follows by the relation $D = A \cdot \lambda \cdot H$.

Forchheimer β-factor

By definition, the Forchheimer β-factor is the high velocity flow coefficient in the flow equation:

$$dP/dx = \mu/K \cdot q + \beta \cdot \rho \cdot q^2$$

where q is volumetric flow rate.

Assuming radial inflow, the non-Darcy term in the inflow equation $1/(T \cdot \lambda) \cdot Q + H \cdot Q^2 = \Delta P$ is calculated as:

$$H = \beta_{rock} \cdot \rho \cdot (1/r_w - 1/r_e)/(4\pi^2)$$

and, similarly for the case of damaged zone around the wellbore:

$$H = \beta_{rock} \cdot \rho \cdot (1/r_d - 1/r_e)/(4\pi^2) + \beta_{damaged} \cdot \rho \cdot (1/r_w - 1/r_d)/(4\pi^2)$$

where:

r_w — wellbore radius

r_e — radial extent of reservoir

r_d — radius of damaged zone

Pipe Flow Models

There are two primary models available in NETool calculate frictional pressure drop inside the well: homogeneous and Beggs & Brill.

Homogeneous Model

The homogeneous model assumes that all phases travel with the same speed in form of a mixture. Under this assumption the following formulas can be applied to calculate frictional pressure drop per unit length.

Reynolds number is defined as:

$$Re = \frac{Dv\rho}{\mu}$$

Usually flow is considered laminar for Re < 2000 and turbulent for Re > 3000. These limits can be changed in **Global Settings→Advanced→Transitional flow regime**.

Different formulas are used for laminar, transitional and turbulent regions:

Laminar flow

Tubing:

$$\frac{dP}{dx} = \frac{32\mu v}{D^2} = \frac{32\rho v^2}{Re\ D} = \frac{f_{laminar}\rho v^2}{2D}$$

where ρ is average fluid density, v is the flow velocity, μ is average fluid viscosity, D is pipe diameter, and $f_{laminar} = 64/Re$ is the Darcy friction factor.

Annulus:

$$\frac{dP}{dx} = \frac{128\mu q}{\pi\left[a^4 - b^4 - \frac{(a^2 - b^2)^2}{\ln(a/b)}\right]} = \frac{32\mu v}{D_l^2}$$

Where: a and b are diameters of outer and inner pipes and

$$D_l^2 = a^2 + b^2 - \frac{a^2 - b^2}{\ln(a/b)}$$

Turbulent flow

Tubing:

$$\frac{dP}{dx} = \frac{f\rho v^2}{2D}$$

With friction factor defined by Haaland:

$$f = \left[1.8\log_{10}\left(\frac{6.9}{Re} + \left(\frac{\varepsilon}{3.7D}\right)^{10/11}\right)\right]^{-2}$$

where ε is pipe wall roughness (m).

Annulus:

Pressure drop and friction factor are given by the same equations as in the case of a circular pipe but with the diameter and Reynolds number replaced with the effective diameter and effective Reynolds number.

The hydraulic diameter is defined as $D_h = 4 \cdot$ Area/Perimeter and for the annulus D_h = a-b.

The concept of the effective diameter is the following:

1) Write the laminar flow pressure gradient in terms of DH and the Darcy friction factor $f_{laminar}$:

$$\frac{dP}{dx} = \frac{f_{\text{laminar}}\rho v^2}{2D}$$

2) Find effective diameter D_J and the corresponding Reynolds number R_J, such that

$$f_{\text{laminar}} = 64/R_j$$

This leads to the following:

$$R_j = \frac{D_l^2 v\rho}{D_h\mu}; \quad D_j = \frac{D_l^2}{D_h} = \frac{a^2+b^2}{a-b} - \frac{a+b}{\ln(a/b)}$$

Transitional flow

The default transition flow regime region in NETool is between Reynolds numbers 2000 (R_2) and 3000 (R_3). The bottom and upper limits of the transition region can be altered.

We assume the flow is laminar when Reynolds number $R < R_2 = 2000$ and the friction factor is:

$$f_{\text{laminar}} = 64/R$$

The flow is considered turbulent when Reynolds number $R > R_3 = 3000$ and the friction factor is given by Haaland's formula above.

For the transition regime $R_2 < R < R_3$ we assume that the friction factor grows linearly:

$$f_{transitional} = \frac{R_3 - R}{R_3 - R_2} f_2 + \frac{R - R_2}{R_3 - R_2} f_3$$

And

$$\frac{dP}{dx} = f_{transitional} \frac{\rho v^2}{2D}$$

Beggs and Brill Model

The Beggs and Brill method (H. D. Beggs, J. P. Brill "A study of two-phase flow in inclined pipes", Trans AIME, vol 256, 607, 1973.) was the first one to predict flow performance at all

inclination angles, including directional wells based on experiments with 1-1.5 inch 90-feet long acrylic pipe.

They proposed the following expression for pressure gradient:

$$\frac{dP}{dx} = \frac{\frac{f\rho_n v^2}{2D} + \rho_s g \sin\Theta}{1 - E_k}$$

Where:

$$\rho_s = \rho_{liquid} H_{liquid(\Theta)} + \rho_{gas}(1 - H_{liquid(\Theta)})$$

And kinetic energy is: $E_k = \frac{v_m v_{sg} \rho_n}{p}$

P_n — a no-slip mixture density

v_m — (q_l+q_g)/Area is the mixture velocity

v_{sg} — the gas velocity

H — v/v_{slip} – "holdup".

Beggs and Brill classified all types of flow into three categories: Segregated, Intermittent and Distributed.

Please note that the Beggs and Brill model is based on experiments for a pipe with diameter 5-10 times smaller than of a typical wellbore.

LMK-1 Model

The LMK-1 gas-liquid pipe flow model identifies the equilibrium flow regime based on the local densities (ρ_L, ρ_G), viscosities (μ_L, μ_G), and superficial velocities (v_{sL}, v_{sG}) of the liquid and gas, as well as the surface tension of the liquid in contact with the gas, σ_L, and the pipe diameter, D, and pipe inclination angle, θ, measured from horizontal and varying between -90° (vertical-downward flow) to 90° (vertical-upward flow). The pipe roughness is an additional input parameter which influences the friction factors that appear in the closure relations of several regime-determining conditions and all pressure drop calculations. The regime transition functions compiled by Barnea (Barnea, 1987) are used to identify the flow regimes. However, some of the functions listed in the 1987 paper were simplified for $\rho_L = \rho_G$, and those have been generalized to apply when ρ_L is only slightly larger than ρ_G. Additionally, cutoff superficial velocities have been included for single-phase flow and a quiescent mixture. The LMK- 1 model is valid over the ranges given in the table, where the superficial velocity ranges apply for subsonic, concurrent flow of the phases. The pressure drop is calculated using several more sophisticated closure relations than those found in the regime identification procedure. Most of the closure models are included in Gomez et al. (Gomez, Shoham, Zelimir, Chokshi, & Northug, 2000).

Parameter	Minimum Value	Maximum Value

Parameter	Minimum Value	Maximum Value
ρ_L	600.0 kg/m^3	1100.0 kg/m^3
ρ_G	0.10 kg/m^3	599.0 kg/m^3
μ_L	0.02 cP (2.0x10^{-5} Pa-s)	5000.0 cP (5.0 Pa-s)
μ_G	0.005 cP (5.0x10^{-6} Pa-s)	5.0 cP (5.0x10^{-3} Pa-s)
σ_L	0.1 dyne/cm (0.0001 N/m)	100.0 dyne/cm (0.1 N/m)
v_{sL}	10^{-4} m/s	300.0 m/s
v_{sG}	10^{-4} m/s	300.0 m/s
D	0.02 m	2.0 m
θ	-π/2 (-90°)	π/2 (90°)

The two-phase regimes identified include dispersed bubble, bubbly (also called bubble), slug, churn, annular and stratified flow. The regime transition functions given by Barnea (Barnea, 1987) also can distinguish between slug and elongated bubble flow, and between stratified smooth and stratified wavy flow, but these distinctions are not resolved in NETool since these sub-regimes do not have unique functions for pressure gradient. Cutoff values of superficial velocity are used to specify single-phase gas, single-phase liquid, and a quiescent mixture regime. A sample regime map for vertical flow is shown in superficial velocity coordinates.

Mechanistic versus Conservation Models

The regime transition functions are based on physical arguments about the flow and account for geometric constraints, balances of forces and linear stability arguments. In particular, the regimes such as annular and stratified flow use a balance of tangential mechanical stress at gas-liquid interface to find the liquid height and film thickness, respectively, in conjunction with mass conservation.

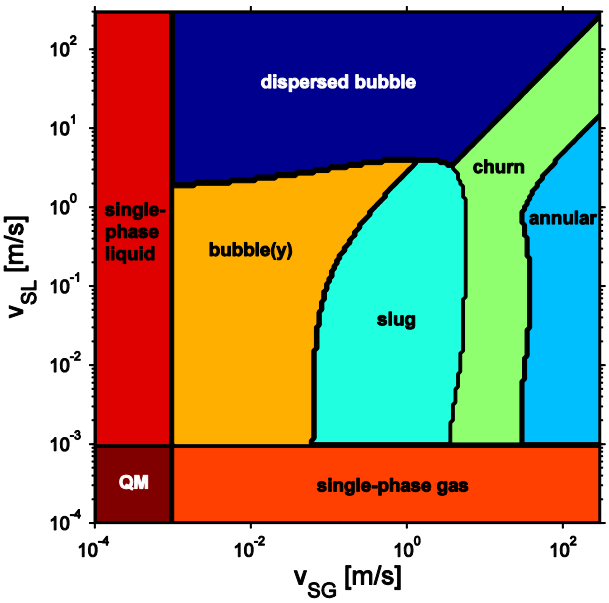


Figure 4. Representative two-phase, gas-liquid regime map for vertical-upward flow. Case shown is for air and water at 20°C and 1 atm.

The derivation of the transition functions considered here are based on assumption of assumptions of one-dimensional and steady-state character of the multiphase flows. These simplifications greatly reduce the computational modelling cost, although in many practical situations the three-dimensional and transient effects need to be taken into account locally, or even in the whole flow domain. On another hand, many simplifying approximations and closure relations are made to match the limitations of the solver engine. For example, in these one-dimensional models, counter-current flow (or counter-flow) is not allowed and the net volumetric flow of liquid and gas must be in the same direction. This allows consideration of only positive superficial velocity values, with the pipe inclination angle specifying the flow direction

Pressure Drop

Like the other correlations available to NETool, the pressure drop in LMK-1 consists of a gravitational (hydrostatic) component and a frictional component, while the acceleration term is neglected. In general, the pressure drop per unit length, given by the negative of the pressure gradient, in the downstream (x) direction can be written as

$$\frac{dP}{dx} = \rho_i g \ \sin\theta + \left(\sum_j \tau_j \frac{S_j}{A_j} \right)$$

for each phase i (liquid and gas), where the last term includes the appropriate shear stress term(s) τ_j, which depend on the geometry of the flow regime, the consideration of slip between phases, and the appropriate closure relations for the regime, for the appropriate perimeter S_j and cross-sectional area A_j over which each shear acts, and where θ is measured from horizontal. Note that

the phases are assumed to be in local mechanical equilibrium, such that only a single value of pressure drop per unit length exists for each location in the pipe.

User Considerations and Sources of Error

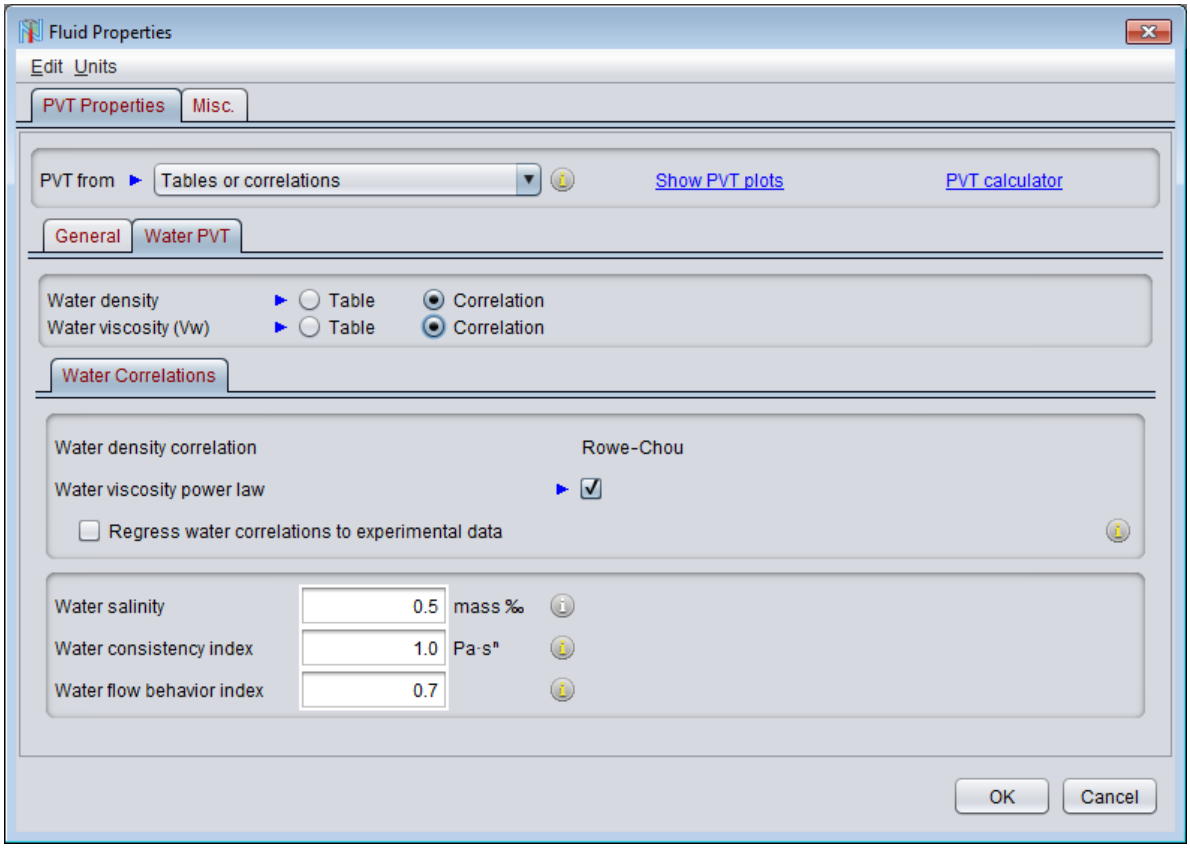
The greatest value to the user is in two scenarios: when the flow regime can significantly impact devices such as pumps, separators or chokes and thus knowledge of the flow regime is highly valuable; and when several regimes might exist along the wellbore and knowledge of the regime characteristics allows a more accurate prediction of the pressure drop. It should be noted that regimes such as churn flow are not universally defined by researchers. LMK-1 uses the definitions found in Barnea (Barnea, 1987), which reference several earlier works such as Brauner and Barnea (Brauner & Barnea, 1986).

NETool iterates on the flow regime and then the pressure drop. Convergence may fail in two ways. First, NETool as a whole may not converge to a solution, either because of a failure to converge within LMK-1, or because of issues that can occur with any model such as insufficient nodal resolution or improper selection of settings. When this happens a warning will be generated to tell the user that no solution was found and a remediation strategy will be suggested. The second possibility is that NETool converges overall, but LMK-1 does not. In this case a warning will notify the user that, even though a solution was generated, it should be scrutinized for accuracy and plausibility. The user should inspect the regimes predicted to see if an instability occurred (for example, repeatedly switching from one regime to another, and back, across just a few nodes). In this case it is recommended that the user switch to a correlation model such as Beggs and Brill. If NETool detects conditions outside the range of applicability of the LMK-1 model, it will warn the user. Here again the user should switch to another correlation model.

There are several sources of error in the LMK-1 model. First and foremost, all of the mechanistic models rely on closure relations which are experimentally determined. Generally the experiments are limited in the types of fluids studied and the configuration of the flow. Furthermore, because NETool allows only a single true velocity at each node, the slip effect captured by many of the regime closure models is not fully utilized in the output results. Additionally, the current LMK-1 model calculates the flow in the annulus using a homogeneous (no-slip between phases) model, though a future release will also treat the annulus flow with a two-phase mechanistic model which includes regime identification. Finally, because some regimes in the LMK-1 model rely on nonlinear, iterative solutions to reduced forms of the momentum equations, it is theoretically possible for the solver to converge to a solution which is mathematically valid, but physically unstable. The LMK-1 model is undergoing continued validation and testing to ensure that these non-physical solutions are avoided, but results should be scrutinized to ensure that solutions are meaningful.

Power Law Fluids

NETool has an option to simulate single phase flow of power-law fluid. When in single phase water mode, a switch "Viscosity from power law" appears in "Fluid properties" window.



This facility simulates a simple non-Newtonian fluid flow known as "Power Law Fluid". Below is the definition of this model and formulas used in NETool simulation.

Shear stress is generally defined as:

$$\tau = \mu\left(-\frac{dV_z}{dr}\right) \qquad (0)$$

where r is perpendicular to velocity V, and μ is fluid viscosity.

The physical meaning of shear stress is a friction force per unit area (unit Pa):

For a power law fluid, relationship (0) has a form:

$$F_{fric} = \tau \cdot A$$

$$\tau = m\left(-\frac{dV_z}{dr}\right)^n .(0)$$

Where:

m — power-law consistency index [Pa·s^n]

n — flow behavior index.

Both Power-law consistency index and Flow behavior index are user entries for NETool modeling of Power Law fluids.

Fluid viscosity from (0) is:

$$\mu = \frac{\tau}{\left(-\frac{dV_z}{dr}\right)} = m\left(-\frac{dV_z}{dr}\right)^{n-1}$$

Laminar flow in a pipe

Pressure drop over the distance L for laminar flow inside a pipe:

$$\Delta p = 2Lm\left(\frac{Q}{\pi\left(\frac{n}{3n+1}\right)R^{\frac{3n+1}{n}}}\right)^n \quad (0)$$

Where:

Δp — pressure drop

L — pipe length

R — radius

m — a power-law consistency index [Pa·s^n]

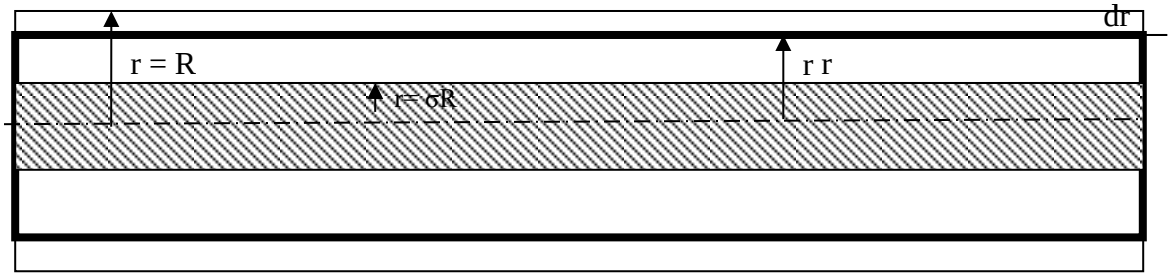
n — flow behavior index

Q — flow rate

Assuming no-slip condition at pipe wall, no angular velocity and fully developed, steady-state flow

Laminar flow in a concentric annulus

Fluid flow through an annulus of outer radius R and inner radius σR will experience two drag forces at inner and outer surfaces.



Pressure drop over the distance L for laminar flow in a concentric annulus:

$$\Delta p = \frac{2mL}{R}\left(\frac{Q}{\frac{n\pi R^3}{3n+1}\left\{(1-\lambda^2)^{(n+1)/n} - \sigma^{(n-1)/n}(\lambda^2-\sigma^2)^{(n+1)/n}\right\}}\right)^n$$

Where:

λ — the location of maximum velocity – is computed from the equation below

Δp — pressure drop

L — pipe length

R — outer radius

σR — inner radius – σ is inner radius / outer radius

m — a power-law consistency index [Pa*s^n]

n — a flow behavior index

Q — flow rate

Assuming no-slip condition at pipe wall, no angular velocity and fully developed, steady-state flow

The value of λ is evaluated by solving:

$$\int_{\xi}^{1}\left(x-\frac{\lambda^2}{x}\right)^{1/n}dx = \int_{\sigma}^{\xi}\left(\frac{\lambda^2}{x}-x\right)^{1/n}dx$$

The following table presents λ for the range of values σ and n:

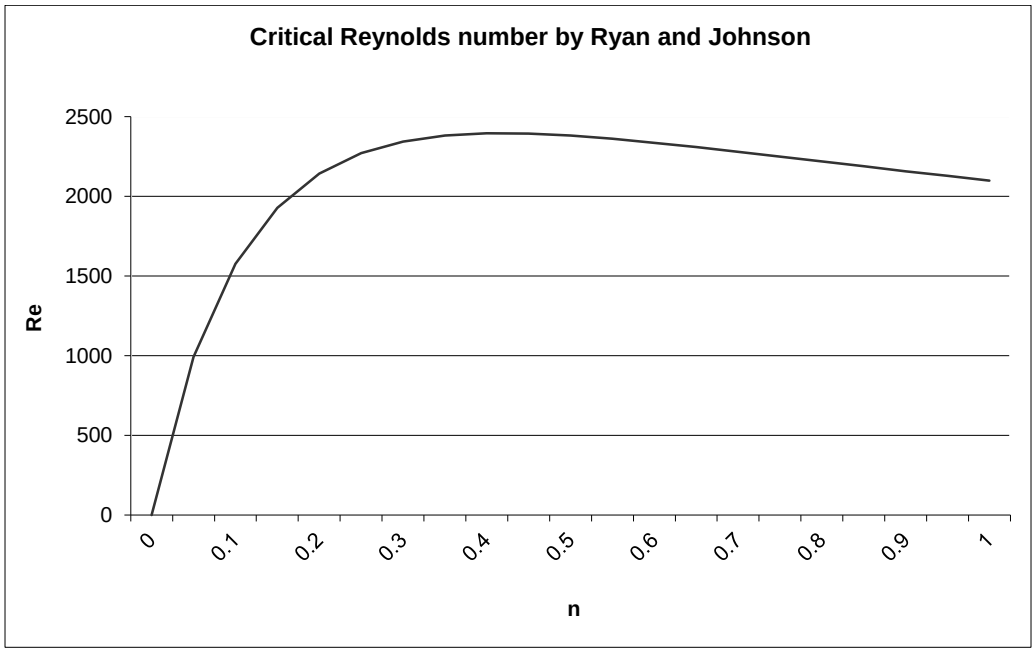
σ / n	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
0.1	0.3442	0.4687	0.5632	0.6431	0.7140	0.7788	0.8389	0.8954	0.9489
0.2	0.3682	0.4856	0.5749	0.6509	0.7191	0.7818	0.8404	0.8960	0.9491
0.3	0.3884	0.4991	0.5840	0.6570	0.7229	0.7840	0.8416	0.8965	0.9492
0.4	0.4052	0.51	0.5912	0.6617	0.7259	0.7858	0.8426	0.8969	0.9493
0.5	0.4193	0.5189	0.5970	0.6655	0.7283	0.7872	0.8433	0.8972	0.9493
0.6	0.4312	0.5262	0.6018	0.6686	0.7303	0.7884	0.8439	0.8975	0.9494
0.7	0.4412	0.5324	0.6059	0.6713	0.7319	0.7893	0.8444	0.8977	0.9495
0.8	0.4498	0.5377	0.6093	0.6735	0.7333	0.7902	0.8449	0.8979	0.9495
0.9	0.4572	0.5422	0.6122	0.6754	0.7345	0.7909	0.8452	0.8980	0.9495

This tables covers only the range of shear-thinning (or pseudo plastic) fluids where viscosity decreases with higher shear rate (velocity). For n=1 the power law model should theoretically give same results as other models for Newtonian flow in annular space.

Criteria for transition from laminar to turbulent flow

Though it is not possible to derive a simple criteria like for Newtonian fluids, the criterion of Ryan and Johnson (AIChEJ 5 (1959) 433) is often used to determine flow regime of power-law fluids:

$$\mathrm{Re}_{crit} = \frac{6464n}{(3n+1)^2}(2+n)^{(2+n)/(1+n)}$$



As it can be seen for n>0.2 a Reynolds number gives values around 2100 – which is pretty similar to Newtonian fluids.

The modeling has been limited to laminar flow because turbulent flow for viscous fluids causes lot of energy dissipation. The viscosity is usually very high for such fluids (around 1 Pa·sec = 1000 cP for zero shear and 10 cP for infinite shear) and is not common fluids for long, narrow pipeline systems. However models for such flow exist and can be implemented though they are more contradictive than for laminar regime.

Completions in NETool

The following completion types in NETool are implemented:

- Inflow Control Valve (ICV), zone isolated completions
- Slotted liner
- Open hole (bare-foot)
- Perforated cemented liner
- ICD's (Inflow Control Devices)
- Nozzle ICD
- Tubular ICD
- Channel ICD
- Halliburton EquiFlow ICD
- Halliburton EquiFlow Adjustable ICD
- Halliburton EquiFlow Nozzle ICD
- Halliburton Autonomous ICD
- Baker Spiral ICD, Troll
- Baker Spiral ICD, general
- Baker Adjustable ICD
- Baker Select ICD
- Baker Helix ICD
- Autonomous ICD
- Wire-wrapped screen
- Generic screen
- Perforated pipe screen
- Gravel pack (as "Screen" + "Formation/Gravel in annulus")
- Cased Hole Gravel Pack (as "Screen" + "Formation/Gravel in annulus" + "Perforated Cemented liner")
- Blank pipe
- Cemented blank pipe
- Packer

Inline tubing choke/plug

For all completions, except Cemented Blank Pipe, a damaged zone around the wellbore can be modeled.

A description of the user interface for the completions is included in the User Manual.

Slotted liner

For this completion type, the user needs to enter (in addition to parameters common to all completion types):

Slot length (m) - L_s

Slot width (m) - W_s

Slot density (m^{-1}) - n_s

Refer to Figure 5.

The total flow area through the completion is assumed large enough to ensure laminar flow through the slots and pressure drop is therefore usually negligible.

The slotted liner model assumes laminar flow and is NOT VALID for LOW SLOT DENSITIES when turbulent flow is likely.

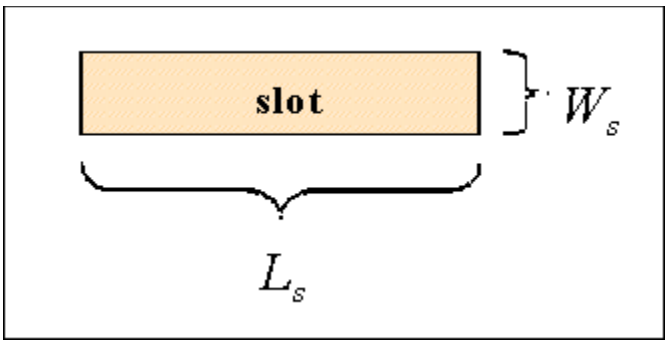


Figure 5. Slotted Liner Schematic

Perforated Cemented Liner

Two models for Perforation Skin are implemented into NETool

Karakas, Tariq - based on work of Karakas and Tariq (SPE 18247) – this model was developed for vertical wells and has been adapted for deviated and horizontal wells
In NETool 1.4.6 this model was referred to as Model #1. It is the original perforation skin model from NETool and the only one available in Version 1.4.5 and older.

Furui, Zhu, Hill – based on work of Furui, Zhu, and Hill (SPE 77363) – this model was developed for horizontal wells and has been adapted for vertical and deviated wells. This model was referred to as Model #2 in NETool Version 1.4.6 and was not available in earlier versions of NETool.

Karakas & Tariq Perforation Skin Model

Basic assumptions of this completion model

laminar flow in perforation tunnels – for high flow rates and low perforation density, this assumption may not be valid.

This correlation is based on work originally developed for vertical wells and adopted for horizontal wells – orientation of the perforations is not considered in the correlation.

Correlation is not valid for perforation lengths and diameters far outside of those generated by current perforating guns.

The skin models described in a paper by Karakas & Tariq are used with the following modification: Karakas & Tariq is developed for vertical wells. A transform has been applied which makes an anisotropic case isotropic. Then the Karakas & Tariq model can be applied also for horizontal wells, and the result is transformed back into the anisotropic case.

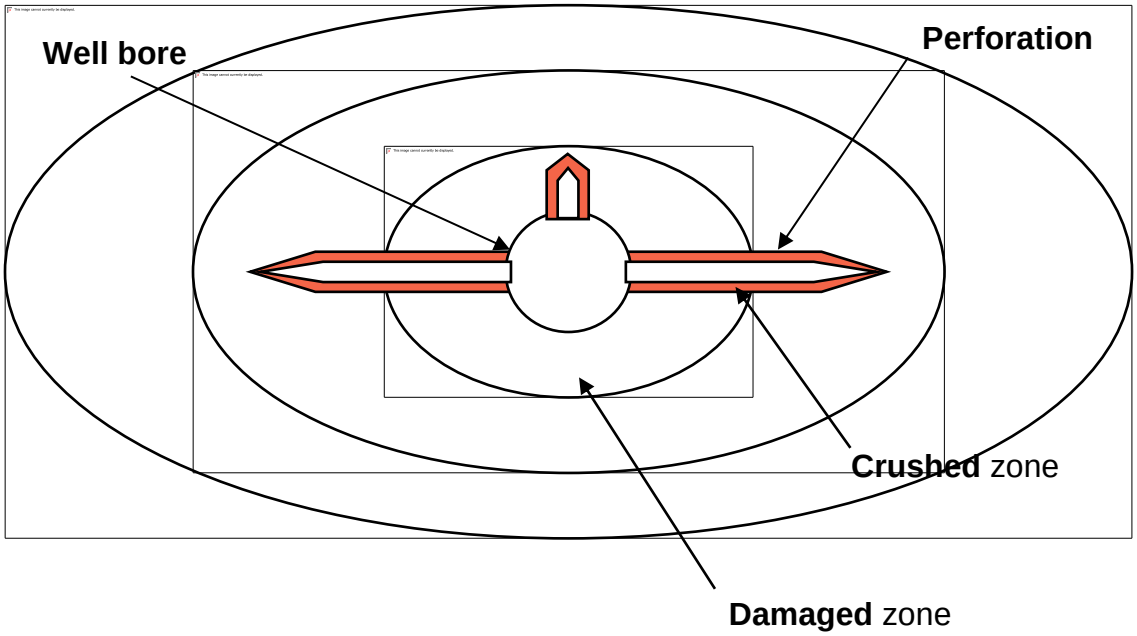


Figure 6. Perforation Skin Model Geometry

Furui, Zhu, Hill Perforation Skin Model

Key assumptions of this completion model

Single phase incompressible fluid – for multi-phase fluids NETool uses average properties.

Effect of gravity is negligible

Well is horizontal – this work is adapted in NETool to vertical and deviated wells.

Pressure drop inside the perforation is negligible – this may not be the case with low shot densities.

In addition, the user should input reasonable perforation parameters – i.e. perforations that can be produced with commercially available perforating guns.

The basis of this skin model is described in more detail in **SPE 77363**.

For this skin model, the same geometry used in Karakas & Tariq Perforation Skin Model described above.

In addition, the effect of perforation orientation is considered. As in the technical paper, the perforation orientation is based upon the angle from the horizontal plane; see Figure 7. The model is symmetric, so only angles between 0° and 90° are valid input. An angle of 90° is used for both high side and low side perforating and the results are similar.

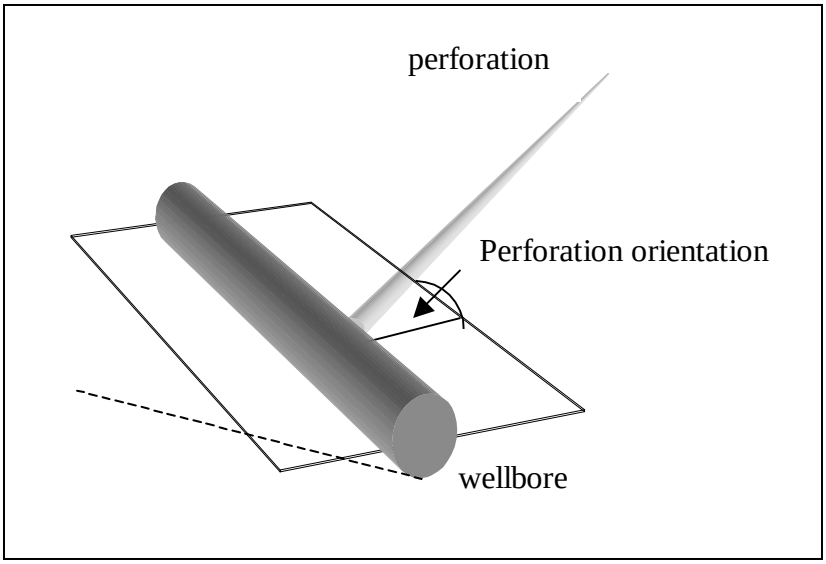


Figure 7. Perforation Orientation in Model #2

Input Parameters for Perforation Skin

The following values are entered in the menu for this completion type:

Perf. Cemented Liner folder under Hole and completion:

Hole diameter - d_p - typically the entrance hole diameter would be used. In the model, this diameter is used as in Figure 6.

Perforation length - L_p - typically the penetration length would be used.

No of shots per meter - n_p (can also be entered as shots per ft with units set appropriately.

Skin Folder:

There are two options for considering skin for the cased, cemented and perforated liner completion. These are

Manual – skin is entered directly by the user. Perforation Skin calculations are NOT performed. If this option is chosen, the other input items are not presented and are not used.

Auto – Skin is calculated based on a damaged zone around the well, crushed zone round the perforation, and perforation phasing angle

Damaged Zone information

Radius of damaged zone - R_d

K_d/K- Damaged zone permeability / formation permeability ratio

Perforation Information

Radius of crushed zone - r_c - see Figure 6.

K_c/K- Crushed zone permeability / formation permeability ratio

Phasing angle - α - phase angle between successive shots in the perforation gun. Common phase angles are 0, 45, 60, 90, 120, and 180. Valid input values are 0 and 45-360º.

Perforation Orientation – this input value is only used with Skin Model #2 and is grayed out when Skin Model #1 is chosen. This is the angle of the perforations from the horizontal plane when considered for a horizontal well, as shown graphically in Figure 6. Commonly high side or low side perforating is used when oriented perforating, both are designated by an input value of 90.

Inflow Control Devices (ICD's)

Inflow Control Devices are special completion components that while allowing flow between the annulus and the tubing place some type of restriction on this flow. Normally the restriction is a pressure drop. These devices are commonly used to even out the pressure drop along a horizontal well to delay gas/water conning. The placement and settings of these devices are designed using NETool.

Nozzle ICD

This is a general implementation for an ICD based on pressure drop across a nozzle as calculated based on Bernoulli's Equation:

$$\Delta P = \frac{\rho v^2}{2\,C^2} = \frac{\rho Q^2}{2\,\mathrm{A}_{valve}^2 C^2} = \frac{8\rho Q^2}{\pi^2 D_{valve}^4 C^2}$$

Where:

ΔP — Pressure Drop across orifice

ρ — Average Fluid Density

V — Fluid Velocity through orifice

Q — Fluid flow rate through orifice

A — Area of orifice

D — Diameter of orifice

C — Flow Coefficient

Flow Coefficient relations:

$$C = \frac{C_D}{\sqrt{\left(1-\beta^4\right)}} = \frac{1}{\sqrt{K}} \qquad \beta = \frac{\mathrm{D}_2}{\mathrm{D}_1}$$

C — Flow Coefficient (NETool is using this one for valves as well)

C_D — Discharge Coefficient

K — Pressure Drop Coefficient

This equation is derived for flow through a single orifice. For multiple orifices in NETool , two basic approaches are appropriate:

Reduce the joint length to cause a higher nozzle/joint density in NETool (this method is only valid if the multiple orifices are the same size.)

Calculate the Effective Diameter of the multiple orifices and use this effective diameter – this method is valid for orifices or varying size.

The effective diameter for multiple nozzles is calculated by taking the square root of the sum of the squares of the diameters of the individual nozzles:

$$d_{effective} = (d_1^2 + d_2^2 + d_3^2 + etc)^{0.5}$$

Tubular ICD

To calculate the pressure drop above the tubular ICD the following equations are used:

$$\Delta P = H_{total}\,\rho$$

$$H_{total} = H_{major} + H_{minor}$$

$$H_{minor} = K_{minor} \times \frac{V_{tube}^2}{2}$$

$$H_{major} = H_f = f \times \left(\frac{L_{tube}}{D_{tube}}\right) \times \left(\frac{V_{tube}^2}{2}\right)$$

$$V_{tube} = \frac{Q_{tube}}{A_{cross-sectional area}} = \frac{Q_{ICD} / Number\ of\ tubes\ in\ parallel}{\Pi/4 \cdot D_{tube}^2}$$

Where:

ΔP — Pressure Drop across tube

ρ — Average Fluid Density

V — Fluid Velocity through tube

Q — Fluid flow rate through tube

A — Area of tube

L — Length of tube

D — Diameter of tube

K_{minor} — Total Minor Loss Coefficient

f — friction factor

Channel ICD

To calculate the pressure drop above the channel ICD the following equations are used:

$$\Delta P = H_{total}\ \rho \cdot \mathrm{v}_2$$

$$H_{total} = H_{major} + H_{minor}$$

$$H_{minor} = K_{minor} \times \frac{V_{channel}^2}{2}$$

$$H_{major} = H_f = f \times \left(\frac{L_{channel}}{D_{hydraulic}} \right) \times \left(\frac{V_{channel}^2}{2} \right)$$

$$V_{channel} = \frac{Q_{channel}}{A_{cross-sectional area}} = \frac{Q_{ICD} / Number\ of\ channels\ in\ parallel}{A_{cross-sectional area}}$$

$$D_{hydraulic} = \frac{4A_{cross\ section\ area}}{U_{wetted\ perimeter}}$$

Where:

ΔP — Pressure Drop across channel

ρ — Average Fluid Density

v — Fluid Velocity through channel

Q — Fluid flow rate through channel

A — Area of channel

L — Length of channel

D — Diameter of channel

K_{minor} —Total Minor Loss Coefficient

f — friction factor

Halliburton EquiFlow ICD

The pressure drop model is supplied by Halliburton and is based on nozzle and frictional physical equations. The model is also verified against Halliburton's own flow experiments.

The ICD type can be one of the predefined settings or be manually specified using the three tube design parameters (length, diameter, number of tubes).

The predefined settings notation denote the pressure drop for a certain rate across the ICD. The pressure drop is given in psi and the rate in bbl/d for a nominal fluid with viscosity 1 cp and specific gravity of 1. For example the predefined setting 20×100 means 20 psi pressure drop at a 100 bbl/d rate thorugh the ICD for the nominal fluid.

The manual option facilitate flexible configuration of the pressure drop chamber in the ICD. A user can specify length and diameter of the tubes, as well as the number of tubes in parallel.

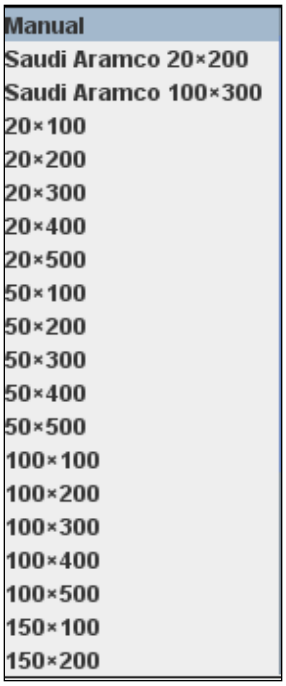


Figure 8. Halliburton EquiFlow ICD Types

Halliburton EquiFlow Adjustable ICD.

The pressure drop is created by six tubes of different diameters. The completion has a threaded removable sleeve to allow access to the flow tubes. The flow profile is changed by closing or opening a pre-determined set of tubes and is carried out at the surface.

ICD consists of 6 tubes:
3 of D = "Tube Diameter" (default is 0.125")
2 of D-0.025"
1 of D-0.05"
Default tube length is 4".

Baker Spiral ICD, Troll

The pressure drop model used in with this option is based on a curve fit to results from a proprietary simulation tool. The proprietary tool has been verified against flow experiments for fluids and flow rates as typical from the Troll oil filed in the Norwegian sector of the North Sea.

This model should not be used for other fluid types than those of Troll. This pressure drop model is not sensitive to the input fluid properties in NETool .

Baker Spiral ICD, General

The pressure drop model used with this option is based on a curve fit to results from a proprietary simulation tool. The proprietary tool has been verified against flow experiments for fluids and flow rates as typical from three Norwegian Oil fields.

The original correlation for these ICD's made based on the results of a proprietary simulation model and the results of four fluids from 3 Norwegian Oil fields, over a viscosity range of 0.064 cp to 10.7 cp, and a density range of 0.234 SG to 0.805 SG.

With Version 2.5 of NETool, an improvement to the Baker Spiral ICD, general model has been made. This improvement involved a transformation of the correlation such that it used reservoir volumes rather than stock tank volumes in the correlation. For fluids with the general viscosity range of 1.8 – 10 cp and densities in the range of 0.805 – 0.892 SG the results of the transformed model are similar (in general +/- 6%). For fluids with lower densities and lower viscosities, the results are both more reasonable and significantly different from the previous implementation, but have not been verified by laboratory experiments.

Baker Adjustable ICD

The pressure drop model used in with this option is based on a curve fit to results from a proprietary simulation tool. The proprietary tool has been verified against flow experiments for fluids and flow rates as typical from three Norwegian Oil fields.

The original correlation for these ICD's made based on the results of a proprietary simulation model and the results of four fluids from 3 Norwegian Oil fields, over a viscosity range of 0.064 cp to 10.7 cp, and a density range of 0.234 SG to 0.805 SG.

With Version 2.5 of NETool, an improvement to the Baker Spiral ICD, general model has been made. This improvement involved a transformation of the correlation such that it used reservoir volumes rather than stock tank volumes in the correlation. For fluids with the general viscosity range of 1.8 – 10 cp and densities in the range of 0.805 – 0.892 SG the results of the transformed model are similar (in general +/- 6%). For fluids with lower densities and lower viscosities, the results are both more reasonable and significantly different from the previous implementation, but have not been verified by laboratory experiments.

Autonomous ICD.

This model allows simulating inflow control devices that use "autonomous" concepts. These include Statoil's Rate Controlled Production (RCP) and Halliburton's EquiFlow AICD. These devices are characterized by a high dependency of pressure drop on flow rate: $dP \sim q^n$ where n can be in a range [3;5].

Wire-wrapped Screen

The wire-wrapped screen model is composed of two main parts:

Pressure drop calculation through the screen: based on the physical dimensions of the equipment.

Pressure drop through a filter cake – based on Darcy type flow calculations.

There is also the option to simulate the annulus of the wire-wrapped screen filled with a porous media, which uses the same calculation technique as the collapsed annulus option.

Pressure drop through the Screen

The pressure drop though the screen is calculated based upon the dimensions of the screen components.

Pressure Drop through Filter Cake

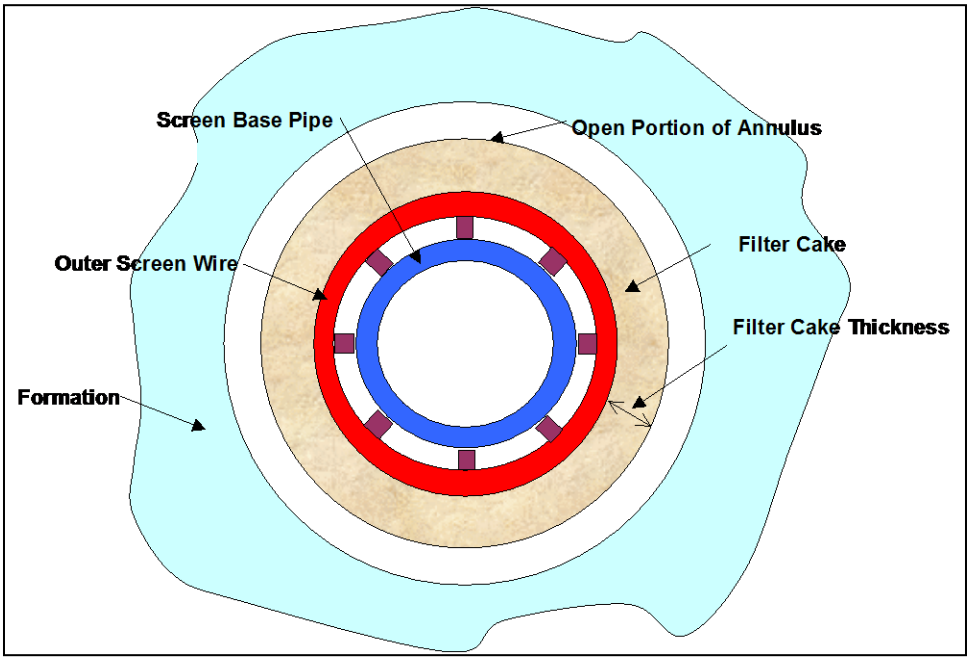


Figure 9. **Conceptual Model for Filter Cake**

The wire-wrapped screen model also includes an option for a filter cake built up on the OD of the screen. Figure 9 shows the conceptual model for filter cake.

The model performs a Darcy type calculation for the additional pressure drop through the filter cake. The open flow area of the annulus is smaller due to the size of the filter cake. When the filter cake option is used, it is assumed that there is no longitudinal flow through the filter cake, but only through the open area of the annulus.

Open hole (barefoot)

The open hole completion includes a damaged zone. Variables for defining damage are entered under the Skin folder of the **Segment Settings/Completion** sheet, and discussed in further detail below.

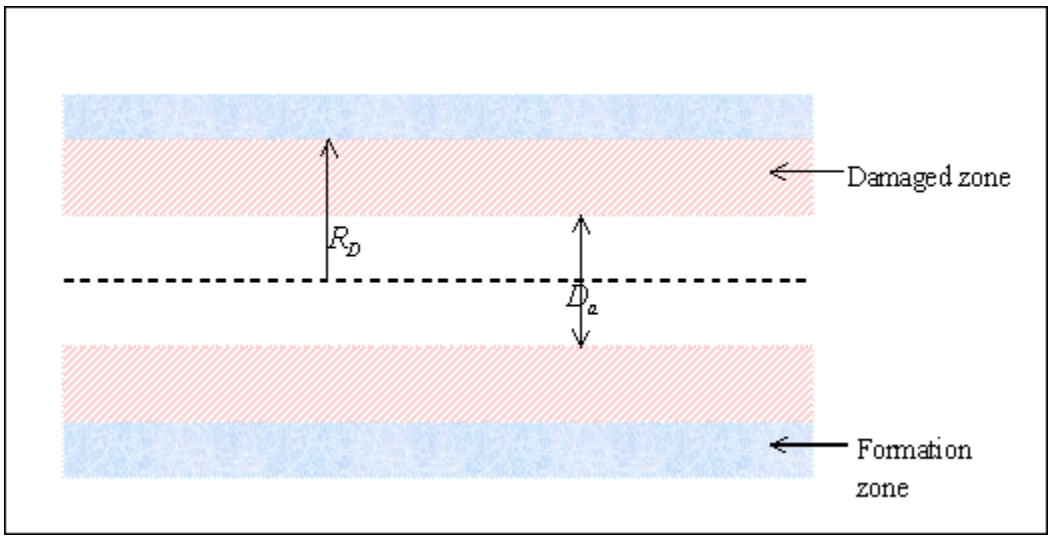


Figure 10. Schematic of open-hole completion.

Where:

D_a — Well bore diameter

R_D — Radius of damaged zone

K_d — Damaged zone permeability

K — Formation permeability

Open Hole Damaged Zone Skin Factor Calculation:

To all completion types (except cemented blank pipe), an automatic damaged zone skin will be calculated (unless the user wants to enter a value for total skin manually).

The values needed to compute a damaged zone skin are entered in the skin menu:

Radius of damaged zone (m) - R_d

K_d/K where K_d is damaged zone permeability and K is formation permeability

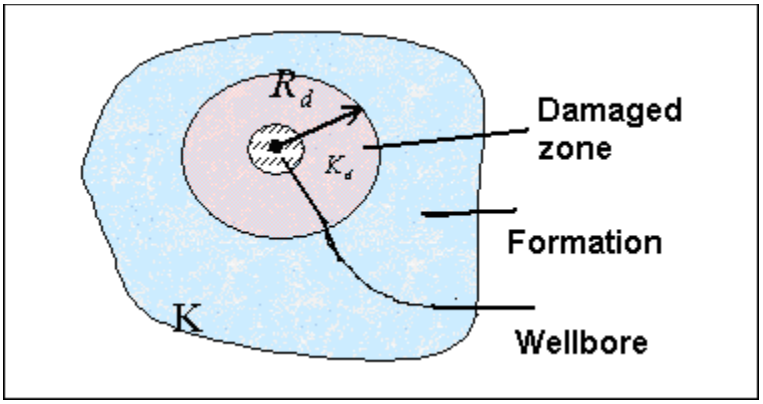


Figure 11. Open-hole damaged zone.

The damaged zone skin factor is applicable to all completions which are NOT cased and cemented, including the following completion types:

ICVS = Downhole Instrumentation and Control – zone isolated completions
Slotted liner
Open hole (bare-foot)
ICD's (Inflow Control Devices)
Spiral ICD, Troll
Spiral ICD, general
Baker Adjustable ICD
Generic ICD
Wire-wrapped screen
Gravel pack (open hole)
Blank pipe

Gravel Pack

This model considers both flow along the annulus through the gravel and the effect of relative permeability on this flow via the Corey Index. Figure 12 shows the gravel pack completion schematically. The wire-wrapped screen parameters input under the wire-wrapped screen completion are used for the gravel pack completion

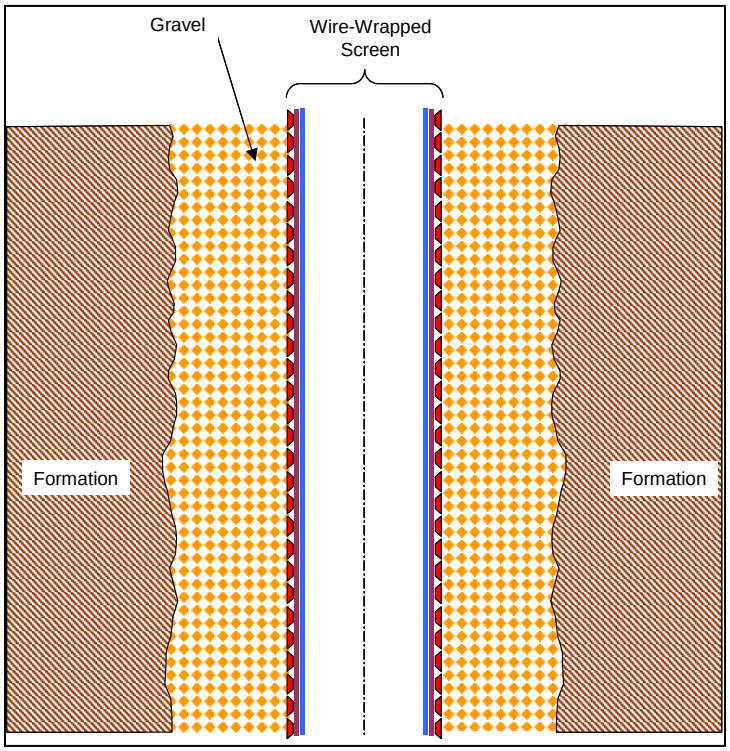


Figure 12. Gravel pack completion.

For flow in annulus filled with gravel, Darcy's law was used:

$$v = K\left(\frac{k_{ro}}{\mu_o} + \frac{k_{rg}}{\mu_g}\right)\frac{\partial p}{\partial x}$$

Where:

K — gravel permeability and

V — total volumetric flux.

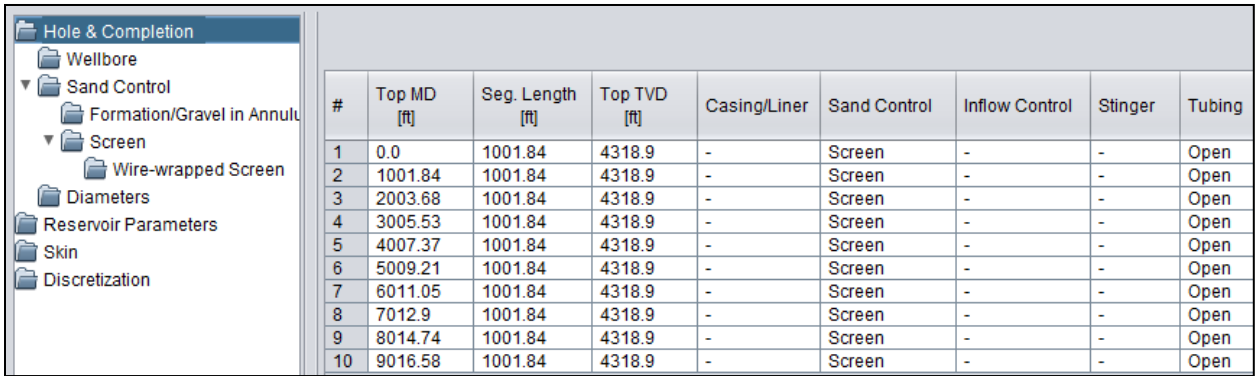
Relative oil and gas perm abilities were replaced by:

$$k_{ro} = \alpha^n, \quad k_{rg} = (1-\alpha)^n$$

Where:

n — "Corey Index".

α — oil fraction



#	Top MD [ft]	Seg. Length [ft]	Top TVD [ft]	Casing/Liner	Sand Control	Inflow Control	Stinger	Tubing
1	0.0	1001.84	4318.9	-	Screen	-	-	Open
2	1001.84	1001.84	4318.9	-	Screen	-	-	Open
3	2003.68	1001.84	4318.9	-	Screen	-	-	Open
4	3005.53	1001.84	4318.9	-	Screen	-	-	Open
5	4007.37	1001.84	4318.9	-	Screen	-	-	Open
6	5009.21	1001.84	4318.9	-	Screen	-	-	Open
7	6011.05	1001.84	4318.9	-	Screen	-	-	Open
8	7012.9	1001.84	4318.9	-	Screen	-	-	Open
9	8014.74	1001.84	4318.9	-	Screen	-	-	Open
10	9016.58	1001.84	4318.9	-	Screen	-	-	Open

Figure 13. Gravel pack in NETool

To model Gravel Pack user should put "Screen" on "sand Control layer and select "Formation/Gravel in annulus".

Cased Hole Gravel Pack

The Cased Hole Gravel Pack Model is for wells which have first been cased cemented and perforated and then had a gravel pack installed inside the casing. This type of gravel pack is also commonly referred to as a remedial gravel pack.

Figure 14 shows the general layout of a well with a cased hole, gravel pack completion.

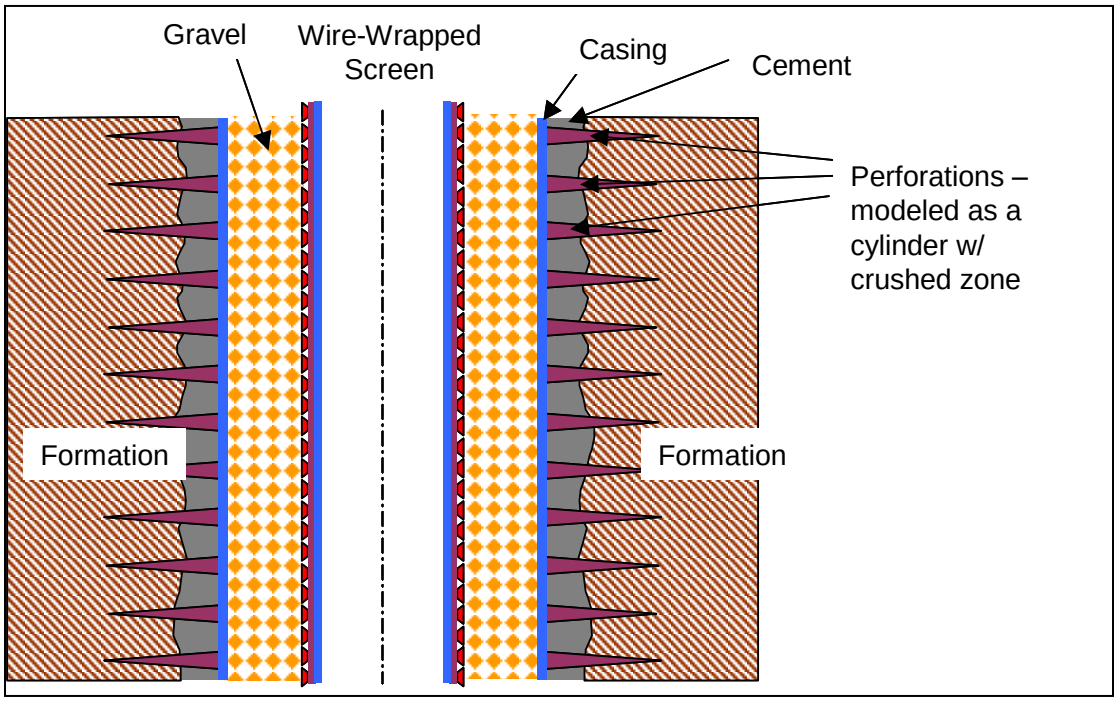
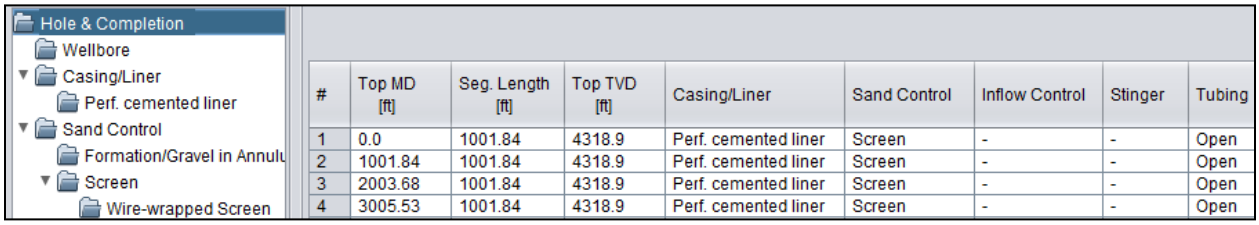


Figure 14. Cased hole, gravel pack schematic.

This model combines elements of the perforated liner completion, for flow from the reservoir into the annulus with both options of the perforated liner model available; the wire-wrapped

screen completion, for flow through the screens; and the gravel pack model for flow through the gravel in the annulus.



#	Top MD [ft]	Seg. Length [ft]	Top TVD [ft]	Casing/Liner	Sand Control	Inflow Control	Stinger	Tubing
1	0.0	1001.84	4318.9	Perf. cemented liner	Screen	-	-	Open
2	1001.84	1001.84	4318.9	Perf. cemented liner	Screen	-	-	Open
3	2003.68	1001.84	4318.9	Perf. cemented liner	Screen	-	-	Open
4	3005.53	1001.84	4318.9	Perf. cemented liner	Screen	-	-	Open

Figure 15. Cased hole, gravel pack in NETool.

To model Cased Hole Gravel Pack user should put “Screen” on “sand Control layer, select “Formation/Gravel in annulus” on “Screen layer and put “Perforated Cemented liner” on “Casing/Liner layer.

The model includes the ability to model open, fully packed, or partially packed perforation tunnels. The perforation tunnel modeling is done by adding an additional pressure drop to the through the perforation tunnels. The flow through the perforation tunnels is modeled assuming that the flow through the perforation tunnel enters the perforation tunnel uniformly along the length of the perforation tunnel and that the perforation tunnel can be effectively modeled as a cylinder.

Pipe flow calculation is used for the unpacked portion of the perforation tunnel. With the diameter of the tunnel defined as Hole Diameter under the Perforated Liner input section, and the flow length defined as ½ the unpacked length of the tunnel
Flow Length = (Length of Perforation – Gravel Filled Perf Length)/2

Darcy type linear flow calculations are made for the gravel filled portion of the perforation tunnel, again assuming that fluid enters the cylindrical perforation evenly along its length
Flow Length = Gravel Filled Per. Length/2

Note: in NETool the pressure drop through the gravel filled (or void) perf tunnel is included in the calculation for the node set for flow between annulus and tubing and does not affect the skin factor as used in the PI equation or displayed on the NETool output.

Blank Pipe

The blank pipe completion is used when a section of blank pipe is run to isolate the tubing from the annulus along a section of the well. This completion type has flow along the annulus – through porous media if collapsed annulus is selected and along the inner diameter of the tubing. There is no flow between the annulus and tubing with the blank pipe completion.

Flow from the reservoir to the annulus is via open hole and the skin options for Open Hole Completion are available.

Cemented Blank Pipe

The cemented blank pipe completion type has only flow through the inner diameter of the tubing/casing. The tubing annulus is not present, and there is no flow from the reservoir for this completion type. This completion type can be used to model un-perforated cemented casing, impermeable zone in open hole, production tubing and other types of completions where an annulus is not present and there is no flow from the reservoir.

ICV and Tubing Plug/Choke

Inflow Control Valve completion type was developed to assist in modeling of smart completions – completions with remote operated downhole valves. ICV (Inflow Control Valve) is a generic term for these types of intelligent completions. This option can be used for both intelligent completions and for completions with chokes set across various zones of the completion.

The network of nodes used with the ICV completion is as described in the figure below.

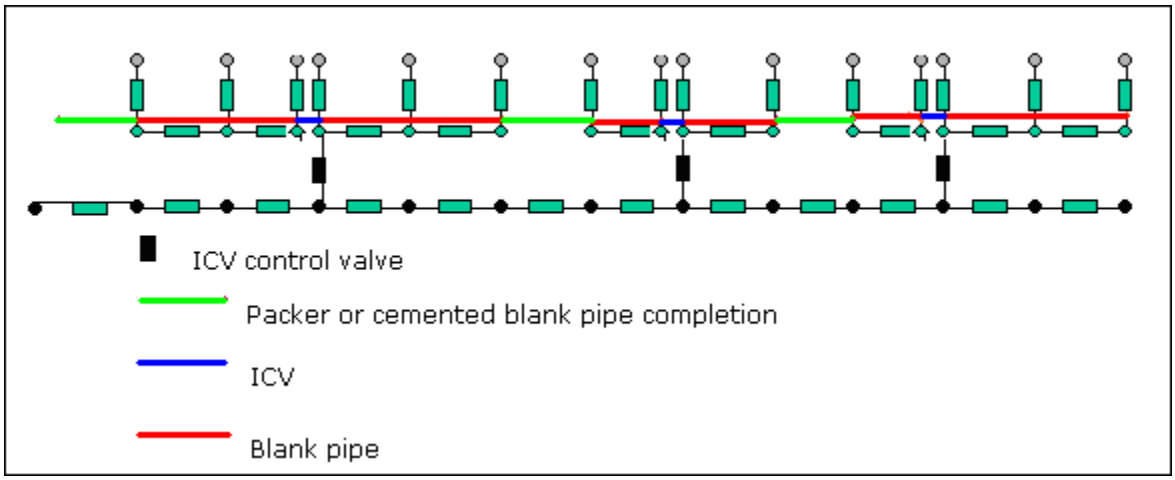


Figure 16. Constructing zone isolation with ICV

For the other completions, there is communication between the annulus and the tubing for every node/segment. With the ICV's completions, there is normally a long section of productive interval with only a single point of communication between the annulus and tubing. For this system, the network as above is more appropriate.

Rules for a valid network geometry with ICV's type completion:

Each ICV's valve (ICV's node) requires a packer (packer node type) above and below

All segments between the packers (packer nodes) and ICV segment should be defined as blank pipe in segment settings (although any other completion can be used instead)

ICV's node/segment groups can be combined with other completion types

There can be multiple ICV's in one zone.

General Steps for Setting up an ICV's Completion

The following are the general steps for setting up an ICV's completion:

Define well path with nodes located at packer setting depth and at ICV valve depth. Any number of intermediate nodes can be used as required to define the completion components and/or reservoir properties.

Define ICV's segments. These are the areas of the completion that are controlled by the ICV's valve. These can be defined either by right clicking the segments in the NETool well/reservoir visualization or via the Segment Settings/Completion Screen. Here the inner and outer diameter of the blank pipe used together with the ICV's control valves is defined. Together with the ICV's control valves is defined.

Define ICV's properties. Four options are available:

Tubing plug/choke and Inflow Control Valve use the same pressure drop methods. The only difference is that the first one has an additional option – "plugged". This completion type can restrict or completely block flow in the tubing. Basically, it is the same valve installed inside tubing instead of annulus-tubing.

Pressure drop method

The following options are available:

- *Plugged* — Flow is completely blocked. (Tubing Plug/Choke only)
- *Valve Opening* — is simplest method, enter the *%open* and the *flow coefficient* of the valve. The percentage open method assumes that with a fully open valve the flow area equals the internal diameter of the Valve, *Tubing ID*.

The calculation used is as follows:

$$\text{valve\_area} = [\%open]\cdot[Tubing\_ID]^2\cdot\pi/4;$$
$$\Delta P = 0.5\cdot\rho\cdot Q^2/(\text{valve\_area}\times\text{flow\_coeffecint})^2$$

Where:

ΔP — pressure drop across ICV device [Pa]
Q — flow rate through the valve [m³/sec]
ρ — average fluid density [kg/m³]

- *Nozzle Diameter* — uses a nozzle type calculation with the effective diameter of the valve entered directly.

The calculation used is as follows:

$$\text{valve\_area} = \text{Nozzle\_Diameter}^2\cdot\pi/4;$$
$$\Delta P = 0.5\cdot\rho\cdot Q^2/(\text{valve\_area}\times\text{flow\_coeffecint})^2$$

Where:

ΔP — pressure drop across ICV device [Pa]
Q — flow rate through the valve [m³/sec]
ρ — average fluid density [kg/m³]

- *Incompressible Valve Table* — this method is for use when a table of valve co-effecients based upon incompressible flow is available for that specific valve. This table of data would typically be supplied by the valve vendor. When this type of calculation is selected, the input areas for *Valve Opening* and *CvXt table* will be active and used.

NETool uses the following formula to calculate flow rate through valve:

$$Q = NC_V \sqrt{\frac{\Delta P}{(\rho_i / \rho_0)}} \qquad \Delta P = \frac{1}{(N C_V)^2} \frac{\rho}{\rho_o} Q^2$$

Where:

ΔP — pressure drop across valve [Pa]
Q — flow rate through the valve [m³/sec]
ρ — inlet density [kg/m³]
ρ_0 — density of water at 15°C = 999.1 [kg/m³]
C_V — valve coefficient supplied by valve vendor [gal/min/$\sqrt{\text{PSI}}$]
N — units conversion constant = 7.5980e-7 (converts C_V to m³/sec/$\sqrt{\text{Pa}}$).

Note: *the CvXt Table contains a column for X_T. This column is NOT used for the incompressible flow calculation*.

- *Compressible Valve Table* — this method is for use when a table of valve coeffecients based upon compressible flow is available for that specific valve. This table of data would typically be supplied by the valve vendor. When this type of calculation is selected, the input areas for *Valve Opening* and *CvXt table* will be active and used.

NETool uses the following formula to calculate flow rate through valve:

$$Q = N C_V \left[1 - \frac{\Delta P}{3 \cdot F_\gamma X_T P}\right] \sqrt{\frac{\Delta P}{\rho / \rho_o}} \qquad \text{if } \Delta P \le F_\gamma X_T P$$

$$Q = const = \frac{2}{3} N C_V \sqrt{\frac{F_\gamma X_T P}{\rho / \rho_o}} \qquad \text{if } \Delta P \ge F_\gamma X_T P$$

Where:

ΔP — pressure drop across valve [Pa]
Q — flow rate through the valve [m^3/sec]
P — ABSOLUTE inlet pressure [Pa]
ρ — inlet density [kg/m^3]
ρ_0 — density of water at 15°C = 999.1 [kg/m^3]
γ — specific heat ratio = 1.25

$F_\gamma = \gamma / 1.40$
X_T — coefficient supplied by vendor (user input)
C_V — valve coefficient supplied by vendor (user input) [gal/min/$\sqrt{PSI}$]
N — units conversion constant = 7.5980e-7 (converts C_V to m^3/sec/$\sqrt{Pa}$).

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