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Guidelines for the Proper Application of Critical Velocity Calculations

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Abstract

Critical velocity calculations in the form of charts or simple equations are frequently used by field personnel to evaluate a gas well's flowing conditions to determine if the well is experiencing liquid loading problems. Literature detailing the critical velocity necessary to keep a gas well unloaded suggests using the conditions at the top of the well as an evaluation point. This is convenient for personnel conducting the evaluation as wellhead pressure and temperature data are readily available. A number of situations exist where the use of the wellhead as the evaluation point can lead to erroneous conclusions. The most obvious situation occurs with a change in geometry downhole when a tapered tubing string is run in a well or when the tubing is set above the perforations. In these instances a more robust evaluation results from using conditions at the bottom of the well and the downhole tubing geometry. Other conditions exist where the use of downhole conditions provide a better evaluation point. The assumptions used in the development of the standard, simplified form of the critical velocity equations and charts may not be appropriate for downhole application. In these cases the fundamental equations must be used. The calculation of critical velocity requires knowledge of pressure, temperature, produced fluids and PVT properties. The determination of critical rate requires the same properties with the addition of pipe diameter. The required PVT properties including surface tension and density for both the gas and liquid phases are reviewed. Correlations to calculate water-gas surface tension were found to have excessive error so a new, more accurate method is presented. This paper provides recommendations when the use of a surface or downhole evaluation point is more appropriate in the determination of the minimum critical gas velocity for a well.

Background

The calculation of critical velocity is frequently used by the operators of natural gas wells to determine the gas production rate required to prevent liquids from accumulating in the well. Turner[24,25] developed a method for calculating critical velocity which has gained wide acceptance and use within the industry. In order to efficiently lift water to the surface, gas wells should produce in the mist flow region where liquid exists as a film on the wall of the pipe or as droplets within the flow stream. The basis for Turner's method is the determination of the gas rate necessary to overcome the terminal fall velocity of a liquid droplet which Turner determined to be the phenomena controlling liquid accumulation in a well. For liquid droplets that are roughly spheroidally shaped, Turner presented the following equation for calculating the terminal fall velocity of the droplet. The required gas flow velocity to keep the well unloaded then equates to this terminal fall velocity.

$$v_t = 6.5493\sqrt{\frac{d\left(\rho_l - \rho_g\right)}{C_d \rho_g}} \quad \text{.....(1)}$$

Examination of this equation shows the terminal velocity to be influenced by the droplet diameter. In order for all liquids to be lifted from the well, the gas velocity must be able to lift the largest diameter liquid droplet. Using work from Hinze[11,12], Turner utilized the Weber Number to determine the maximum droplet diameter. The Weber Number is a dimensionless quantity that is determined by dividing the inertial forces that act to breakup liquid droplet by the interfacial forces which act to hold the droplet together. For conditions in a gas well, Turner reported this critical Weber Number to range 15-30 as determined from the following equation.

$$N_{we} = \frac{14593.9 \rho_g d v^2}{g \sigma} \quad \text{.....(2)}$$

Therefore, if the largest value, 30, is selected, the maximum droplet diameter can be determined as follows.

$$d_{\max} = \frac{30\, g\, \sigma}{14593.9 \rho_g v_t^2} \quad \text{.....(3)}$$

The drag coefficient, C_d, in Eqn. 1 relates to the particle Reynolds Number[15]. For the conditions of interest in a gas well, Turner reported that the particle Reynolds Number is on the order of 10^4 to 10^5; therefore, the drag coefficient is constant with a value of 0.44. By substituting this value for the drag coefficient and Eqn. 3 into Eqn. 1, the equation for critical velocity is developed.

$$v_c = 1.5934 \left[\frac{\sigma(\rho_l - \rho_g)}{\rho_g^2} \right]^{0.25} \quad \text{.....(4)}$$

Turner proposed the following as likely values for condensate and water properties used in Eqn. 4.

Property	**Water**	**Condensate**
Surface tension, dynes/cm	60	20
Density, lbm/ft^3	67	45

Table 1 – Liquid property assumptions proposed by Turner

Gas density varies with gas gravity, pressure and temperature. Using the assumptions below, the gas density can be approximated using a simple equation with pressure.

Property	**Value**
Gas gravity	0.6
Temperature, °F	120
Gas Z factor	0.9

Table 2 – Assumptions of simplified gas density

The gas density is rigorously determined using the real gas equation.

$$\rho_g = \frac{p\, \gamma_g\, M_a}{Z\, R\, T_{\circ R}} \quad \text{.....(5)}$$

By substituting the values from Table 2 into Eqn. 5, a simplified pressure equation was developed.

$$\rho_g = 0.0031 p \quad \text{.....(6)}$$

If both condensate and water are present in the well the heavier liquid phase (e.g. water) properties should be used to evaluate the critical unloading velocity. Turner also recommended that Eqn. 4 be evaluated using surface conditions provided a constant pipe diameter exists in the well.

Turner tested his assumptions and equations against a database derived from well and lab tests consisting of 138 data points. Wells producing gas condensate only (94 tests) provided a majority of the data. Turner found the method better replicated the database if the critical Weber Number was increased from 30 to 60. Applying this finding results in the increase of the coefficient in Eqn. 4 by 1.1892 or "approximately 20%" as stated by Turner. This increase can essentially be viewed as a safety factor to ensure the well is unloaded. The final equation is then

$$v_c = 1.8949 \left[\frac{\sigma(\rho_l - \rho_g)}{\rho_g^2} \right]^{0.25} \quad \text{.....(7)}$$

In a later work, Coleman et al[3-6] evaluated Turner's method against a database of 56 wells (6 gas condensate only). Coleman et al did not follow the standard recommendation to use condensate liquid properties for cases where condensate was the only reported produced liquid. Instead, their data was evaluated using only water properties. The basis for this assumption lies in the fact that all gas wells produce equilibrium water vapor from the reservoir which typically condenses in the tubing as pressure and temperature decrease from the bottom of the well to the surface. This was demonstrated by Sutton et al[20] in 2003. Therefore, Coleman et al concluded that water properties should always be used to evaluate critical velocity. They also reported that the adjustment factor recommended by Turner was unnecessary.

Review of Turner's Assumptions

Fluid Density

The Turner assumption for water density is found in the thesis. While oil field waters contain varying amounts of dissolved salt, Turner assumed a "typical" salinity of formation brine to be 28,000 ppm and stated a corresponding water specific gravity of 1.08. An examination of oil field waters from around the world is found in Fig. 1. Note that water with a specific gravity of 1.08 has a salinity of 102,000 ppm. Conversely, water with a salinity of 28,000 ppm has a specific gravity of 1.025. Condensed water does not contain any dissolved salts and has a specific gravity of 1.0. When performing these calculations a density consistent with the water produced from the well should be used in the determination of critical velocity. Since water is only slightly compressible, pressure has little effect on the density of water. Conversely, temperature can significantly affect water density. In the case of condensate, both pressure and temperature affect density. The condensate is in contact with natural gas and will contain varying amounts of solution gas depending on pressure and temperature. Liquid density can be rigorously calculated using the following equation.

$$\rho_l = \frac{\left(62.366\gamma_l + 0.0136\gamma_g R_s\right)}{B_l} \quad \text{.....(6)}$$

Suitable correlations for estimating condensate and water PVT properties are listed in Appendix A. The solution gas-water ratio has a negligible effect on water density and is ignored. Fig. 2 summarizes the affect of pressure and temperature on condensate and water density.

The simplifying assumption proposed by Turner to express gas density is valid over a limited pressure range and only at the temperature defined. Fig. 3 illustrates this concept. At the defined temperature of 120 °F, the gas density is accurately represented up to about 1200 psia. At higher pressures, the error increases. A change from the assumed temperature results in a larger error which also grows with pressure.

Surface Tension

In Turner's original study a constant value of surface tension was used as presented in Table 1. Since Turner's publication, correlations to evaluate gas-water surface tension have been proposed in the literature. Recent improvements in a correlation developed by Sutton[23] offer a means to reliably evaluate this property. Turner's assumption of 60 dynes/cm for gas-water surface tension is approximate for pressures between 2000-3000 psia and 120 °F. However, surface tension is a function of pressure and temperature and should be accounted for in the calculations. This relationship is presented in Fig. 4. Turner's recommendation for condensate-gas surface tension was taken from a graph of pure hydrocarbon surface tension at elevated temperatures. It is not indicative of the surface tension between a condensate-gas mixture encountered in a gas well at elevated pressure and temperature. Katz[13] discusses the effect of pressure and temperature on condensate-gas surface tension and indicates that values less than 2 dynes/cm (an order of magnitude less than Turner's assumed value) are likely at pressures above 3000 psia. The variation in this value with pressure and temperature relates to changes in solution gas-oil ratio. Fig. 4 also illustrates the change in condensate-gas surface tension for a 45 °API condensate. The value of 20 dynes/cm assumed by Turner is only representative for conditions less than 250 psia. Suitable correlations for estimating surface tension are summarized in Appendix A.

Neglecting the changes in PVT properties with pressure and temperature can introduce errors in the derived critical velocity with changing pressure and temperature. For gas-water evaluations, the maximum error is generally less than ±20%; however, for gas-condensate systems, the error can be in excess of 100%. Examples of these errors are provided in Figs. 5 and 6 for a range of conditions likely encountered in the field. At low pressures often associated with liquid loaded wells, these errors may be acceptable. However, for the pressure and temperature conditions evaluated in this paper, the relationships have been fully defined in order to achieve a consistent result.

Application of Turner's Method

Evaluation Location

As discussed in the literature, the accepted evaluation point for calculating the critical velocity is the wellhead. This location

is convenient as wellhead pressure and temperature are readily available. This recommendation assumes a constant wellbore geometry and must be modified when the wellbore geometry is not constant. A review of Fig. 7 helps explain this concept. In many cases, the critical velocity can be relatively constant with depth. The flow velocity may exceed the critical velocity in the tubing; however, if the end of tubing is set above the producing interval, the resulting flow velocity in the casing will be much lower and can easily be less then the critical velocity. In this instance, the critical velocity should be determined for the larger diameter flow conduit and the conditions at this point in the well should be used to determine the corresponding gas flow rate.

For instances where the flow geometry is constant, the evaluation of a minimum gas production rate should allow for the critical velocity to be exceeded along the entire flow path. This philosophy ensures that liquid cannot accumulate in the well. If the flow velocity drops below the critical velocity near the bottom of the well, the flow regime will change from mist to slug flow and liquid can begin to accumulate. As the process continues, a static liquid column[17,20] is often noted in the bottom of the well. This is a gaseous liquid column as a result of gas producing through the liquid which exhibits a reduced mixture density.

As well locations change around the world, the geothermal temperature gradient can vary with an approximate range of 0.8-2.2 °F/100 ft. Fig. 8[18] developed by the SMU Geothermal Laboratory depicts this variation for the United States. The geothermal temperature gradient is a variable quantity with depth, especially in areas with active geothermal activity. For the purposes of this evaluation, a constant gradient with depth is assumed. The flowing temperature gradient in low rate wells undergoing liquid loading will track the geothermal gradient. For cases where excess heat is carried to the surface, the actual flowing temperature gradient will be less than the geothermal gradient. Therefore, the geothermal gradient represents the maximum temperature gradient anticipated in a well.

In order to test the recommendation of evaluating critical velocity at the wellhead a calculation test matrix was established with the following properties held constant.

Property	**Value**
Depth, ft	10,000
Tubing ID, in	2.441
Wellhead temperature, °F	70
Gas gravity	0.65
Water-gas ratio, STB/MMCF	0

Table 3 – Initial test matrix (constant properties)

The bottomhole temperature was assumed to range 100-450 °F to simulate the change in geothermal temperature gradient with location. This initial test matrix assumes that no free water exists in the well. This simplified assumption allows the calculation of pressure drop in the well and avoids the controversy of the selection of an appropriate correlation to accurately evaluate multiphase flow pressure drop. For each evaluated wellhead pressure, the critical velocity at the surface is calculated which establishes the evaluation flow rate. Bottomhole pressure is calculated along with the corresponding PVT, bottomhole critical velocity and flow velocity. Figs. 9-11 provide an example for two of the assumed conditions. The change in temperature has a small effect on the calculated bottomhole pressure; however, the effect on the velocity calculations is more significant. For the low temperature gradient simulation in this example, the resulting bottomhole flow velocity is less than the critical velocity while converse is true for the high temperature gradient simulation. Based on this result, additional calculations were performed to determine the temperature gradient that results in an identical bottomhole flow velocity and critical velocity for wellhead pressures ranging from 15-3000 psia and the conditions stated in Table 3. The results of these calculations are provided in Fig. 12. The line in Fig. 12 provides a boundary that determines which point in the well should be used to evaluate critical velocity. For wells where the geothermal temperature gradient and wellhead pressure results in a point located below the boundary, the bottomhole pressure and temperature should be used to evaluate critical velocity. Conversely, for producing conditions that result in a point above the boundary, the wellhead pressure and temperature should be used to evaluate critical velocity. In general for higher pressure operations, the wellhead is an appropriate evaluation point as recommended by Turner. As the wellhead pressure decreases, the likelihood of using the bottomhole conditions for evaluating critical velocity increases. For low pressure operations with wellhead pressure less than 100 psia, almost all scenarios would require the use bottomhole conditions.

These results were based on the test conditions summarized in Table 3 and demonstrate conditions where a bottomhole evaluation point is warranted. The remaining text discuses the sensitivity of the conclusion based on changing surface temperature, wellbore geometry, gas gravity, well depth, the actual presence of free water, water salinity and condensate.

Flowing Temperature Gradient

The evaluation procedure outlined above was repeated for wellhead temperatures ranging from 40-150 °F. The results are provided in Fig. 13. A small variation in results is noted at very low wellhead pressures; however, at wellhead pressure above 100 psia, the results are essentially the same. This result allows us to more generally conclude that it is not the geothermal temperature gradient, but that actual flowing temperature gradient that contributes to the position of the appropriate calculation boundary.

Tubing diameter

The critical velocity determined at the wellhead has been used to set the evaluation flow rate for a given tubing size. Therefore as the tubing diameter changes, a corresponding change in flow rate is noted due to the change in crossectional area. While the required flow rate to maintain critical velocity increases with increasing tubing diameter, the corresponding friction loss decreases with increasing tubing size and thus resulting in a lower bottomhole pressure for larger tubing diameters. The governing equation for determining friction loss is as follows.

$$\left(\frac{\partial p}{\partial L}\right)_f = \frac{1}{144}\frac{f\rho v^2}{2g\,d} \quad \text{.....(7)}$$

The friction factor, f, in Eqn. 7 is a function of pipe relative roughness and Reynolds Number. A constant absolute pipe roughness (0.0006 in) typical of oil field tubing was used in this evaluation. As the pipe diameter changes, a corresponding change in the relative roughness, ε'/d, is noted. The Reynolds Number is determined from the following equation.

$$N_{re} = \frac{1488\rho v d}{\mu} \quad \text{.....(8)}$$

Therefore Reynolds Number also changes with variations in tubing diameter. The end result is the frictional pressure drop is reduced for a constant density and velocity scenario when the tubing diameter is increased. However, the flow rate will increase for this constant velocity scenario due to the increase in crossectional area of the pipe.

Fig. 14 provides the results from evaluating the effect of tubing diameter ranging 1-7-in (nominal). The higher friction pressure drop encountered with the smaller diameter tubing shifts the result upwards. This outcome is small at wellhead pressure above 1000 psia. At lower wellhead pressure where the critical velocity increases, the change in frictional pressure drop relative to the hydrostatic pressure drop results in a wider range of solutions. For large diameter tubing and low wellhead pressure, the boundary is much lower than the result determined for small diameter tubing scenarios. Therefore, for large tubing diameter wells, it is more likely that evaluations using wellhead conditions will be appropriate. For wells with small diameter tubing, it is likely that critical velocity should be determined using bottomhole conditions.

Gas Gravity

Most gas wells produce gas with a relatively low hydrocarbon wellstream specific gravity ranging from 0.554 (methane) to approximately 0.75. Gas condensate wells will have a much higher wellstream gravity depending on the condensate yield (Fig. 15); however, as pressure and temperature drop in the well as the gas is produced to surface, the liquid hydrocarbon condenses from the gas which acts to preserve a lower specific gravity in the gas phase. Fig. 16 shows the result for a varying gas gravity scenario. The change in outcome is subtle; therefore, gas gravity has little impact on the selection of surface or downhole evaluation points for critical velocity but is important when calculating the flow velocity and required rate.

Well Depth

The impact of well depth is shown in Fig. 17. At higher wellhead pressure, the results are essentially identical for all ranges of depth. At low wellhead pressures a separation in results is noted. Figs. 18 and 19 examine the difference between the critical velocity and flow velocity for the base case. For the solution condition, the difference in critical velocity and flow velocity is determined with depth. The results of this analysis identify flowing conditions where the critical velocity calculated by the Turner method can be higher than the flow velocity at depths below the surface and yet equal at the wellhead and at bottomhole. Based on our findings, the maximum difference occurs at approximately the mid-point depth of the well and ranges from approximately 10% for the low wellhead pressure scenario to 0.2% for the high pressure scenario. Turner recommended that the calculated critical velocity be increased by approximately 20% as a safety factor to ensure the well is unloaded. Since the velocity difference is less than the safety factor, the critical velocity at the top or bottom of the well can be used as appropriate. As wellhead pressure and temperature gradient deviate from the boundary line, this anomaly is not noted.

Free Water

When free water is present in the well, the resulting pressure gradient in the well is increased. Gray[10] published a method for calculating the pressure drop resulting from the flow of gas and water which Oudeman[14] recently reviewed providing more details and correction to the original work. The method for gas water surface tension outlined in Appendix A was used in these calculations as it provides for a more accurate result for that quantity.

In the previous scenarios investigated, it was determined that the boundary between surface and bottomhole evaluations shifted to higher temperature gradient for situations where the friction loss increases relative to the hydrostatic loss. For cases where free water is produced, the overall pressure drop is larger, and the boundary shifts to a higher temperature gradient. These results are provided in Fig. 20. For all wellhead pressure scenarios less than 1000 psia, the indicated point in the well for determining the critical velocity is the bottom of the well. As the water-gas ratio is increased, the boundary shifts to an even higher temperature gradient as a result of the larger pressure drop in the well. As a practical result, whenever free water is present in the flow stream, the proper evaluation point is most likely downhole unless the wellhead pressure is high.

Water Salinity

The increase in water salinity results in an increase in water specific gravity as shown by the field data provided in Fig. 1 which translates into an increase in water density as described by Eqns. A14 and A16-A23. Furthermore, there is an increase in water-gas surface tension as described by Eqn. A31. The effect on critical velocity is an increase with salinity as described by Fig. 21. An increase in bottomhole pressure with increased water salinity is also noted. As water salinity increases, the boundary between surface and bottomhole evaluations shifts to a higher temperature gradient as shown in Fig. 22. However, the change is small and does not significantly alter the selection of critical velocity evaluation point.

Gas Condensate

The use of gas condensate PVT properties for the evaluation of critical velocity results in a lower velocity compared to an evaluation using water PVT properties since condensate density and surface tension are less than water values for a given pressure and temperature. As discussed by Turner, the use of condensate properties to evaluate critical velocity is only appropriate in the absence of water. As further discussed by Coleman, the gas produced from a reservoir will contain equilibrium water vapor which condenses in the tubing. As a result, it is appropriate to evaluate the critical velocity using water PVT properties for most instances. For situations that dictate an evaluation using condensate PVT properties, Fig. 23 illustrates a downward shift in the equilibrium boundary between surface and downhole evaluation location. The typical evaluation point is the wellhead except for low wellhead pressures where the temperature gradient is insufficient to warrant the use of wellhead pressure and temperature.

Turner Ratio

In 2003, Veeken et al[26] introduced the concept of a Turner ratio. This quantity is defined as the observed critical rate divided by the calculated critical rate as defined by Turner and was originally related to wellhead pressure and reservoir deliverability. Similarly a Turner ratio can be defined for this work. In the context of this work, it is defined by dividing the bottomhole critical rate by the wellhead critical rate. Veeken et al demonstrated with field data that the Turner ratio is greater than unity for high deliverability, low pressure wells. This is a sound conclusion as the additional backpressure resulting from water production from a low pressure-high deliverability reservoir will have very adverse effects on the production rate. This scenario complicates the evaluation as reservoir deliverability issues are mixed with critical velocity issues. This work leads to a more general conclusion irrespective of the reservoir, that bottomhole conditions should be used to evaluate critical velocity for low wellhead pressure scenarios. This scenario results in a higher flow rate and a Turner ratio greater than 1 which is consistent with Veeken's findings. Fig. 24-26 provides the Turner ratio for several scenarios. These charts show the same characteristics as the relationship proposed by Veeken et al but do not include a reservoir component. Use of these charts allows the critical rate to be evaluated using wellhead conditions and then modified with the Turner ratio to ensure the entire wellbore is unloaded.

Examples

Two examples are presented to illustrate the concepts in this paper. All calculations make use of the assumptions outlined in Table 3.

Example 1 - A well produces a lean gas-condensate. The yield is 0.5 STB/MMCF and there is no reported water production. Reservoir pressure is 1000 psia with a temperature of 225 °F. The producing conditions at the surface are 500 psia and 70 °F resulting in a producing temperature gradient of 1.55 °F/100 ft. The water vapor content of the gas as it is produced through the tubing is established in Fig. 27. The equilibrium water content (determined using a method from Bukacek[2]) of the gas in the reservoir is 3 STB/MMCF which condenses in the well above 8500 ft. Therefore, despite to absence of reported water production, the critical velocity is evaluated using water PVT assumptions and wellhead conditions resulting in a critical rate of 1154 MCFD. A check with Fig. 12 shows that surface conditions should be used to evaluate critical velocity based on the wellhead pressure and producing temperature gradient. The calculated velocity gradients are presented in Fig. 28 and

confirm the analysis based on wellhead conditions.

Example 2 - A low pressure well produces to wellhead conditions of 15 psia and 70 °F. Reservoir pressure is 175 psia at 225 °F. The resulting temperature gradient is 1.55 °F/100 ft. For this well, the critical velocity should be evaluated using downhole conditions as indicated by Fig. 12. The equilibrium water content for the gas in the reservoir is 15 STB/MMCF and the evaluation shown in Fig. 29 indicates condensed water above 5500 ft so critical velocity should be evaluated using water properties. Despite the recommendation of using bottomhole conditions as the evaluation point, the critical velocity is determined at the wellhead resulting in a gas production rate of 195 MCFD. An examination of the velocity profiles in Fig. 30 shows the well to be producing below the critical velocity. The Turner ratio from Fig. 24 is 1.54 for these wellhead conditions which corrects the critical rate to 299 MCFD. The resulting velocity profiles shown in Fig. 31 show the flow velocity to be larger than the critical velocity along the entire wellbore.

Conclusions

1. Simple yet accurate methods have been provided to calculate the PVT necessary for liquid loading calculations. The results are compared to those obtained using simplified critical velocity equation formulations. The current method used for gas condensate wells results in excessive error. In most cases though, the critical velocity should be evaluated using water properties.
2. PVT correlations necessary to evaluate the fluid properties required for critical velocity calculations are presented in Appendix A. A new more accurate method to predict gas-water surface tension has been developed which enhances the accuracy of these calculations.
3. The critical velocity is essentially the boundary between slug and mist flow. The entire wellbore should be in the mist flow regime to ensure liquids are unloaded from the well. Failure to produce the well above the critical velocity can result in the accumulation of water in the bottom of the well.
4. The evaluation point for determining critical velocity can be at either the wellhead or bottomhole. In general, high pressure application with the wellhead pressure greater than 1000 psia should evaluate critical velocity using wellhead conditions. Low pressure operations less than 100 psia should evaluate critical velocity using bottomhole conditions. If the well is producing free water, most scenarios for wellhead pressure less than 1000 psia indicate the use of bottomhole conditions.
5. The Turner ratio charts can be used to augment critical velocity calculations using wellhead conditions to produce a result that ensures liquids are unloaded along the entire length of the wellbore.
6. Turner provided for an 18.92% safety factor in his original work to determine critical velocity. Analysis of velocity profiles along the boundary line illustrates the need for this safety factor to ensure the well is unloaded along the entire flow path.

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Nomenclature

A_p = crossectional area to flow, ft^2
B_{ob} = bubblepoint oil FVF, BBL/STB
B_{ob}^* = correlating number for bubblepoint oil FVF calculation
B_l = liquid FVF, BBL/STB
B_w = water FVF, BBL/STB
B_w^o = water FVF at atmospheric pressure and reservoir temperature, BBL/STB
C_s = salinity, ppm
d = diameter, ft
f = Moody friction factor
g = acceleration due to gravity = 32.17 ft/sec^2
L = length, ft
M = molecular weight, lb-mole
M_a = air molecular weight = 28.964 lb-mole
N_{re} = Reynolds Number, dimensionless
p = pressure, psia
p_b = bubblepoint pressure, psia
p_b^* = correlating number for bubblepoint pressure calculation
p_{pc} = pseudocritical pressure, psia
$p_{pc}*$ = pseudocritical pressure with intermediate nonhydrocarbon adjustment, psia

p_{pr} = pseudoreduced pressure
q_g = gas flow rate, MCFD
R = universal gas constant =10.73147 psia-ft^3/°R-lbm mol
R_s = solution gas-liquid ratio, SCF/STB
$T_{\circ F}$ = temperature, °F
$T_{\circ K}$ = temperature, °K
$T_{\circ R}$ = temperature, °R
T_{pc} = pseudocritical temperature, °R
T_{pc}* = pseudocritical temperature with intermediate nonhydrocarbon adjustment, °R
T_{pr} = pseudoreduced temperature
v = velocity, ft/sec
v_c = critical velocity, ft/sec
v_t = terminal velocity of liquid droplet, ft/sec
w_s = salinity, weight fraction
y = mole fraction in gas phase
Z = gas compressibility factor
ε' = absolute roughness, in
ε = pseudocritical temperature adjustment parameter, °R
γ_g = gas specific gravity
γ_{gHC} = hydrocarbon gas specific gravity
γ_l = liquid specific gravity
ρ_g = gas density, lbm/ft^3
ρ_h = hydrocarbon density, g/cc
ρ_l = liquid density, lbm/ft^3
ρ_w = water density, g/cc
σ_{gw} = water-gas surface tension, dynes/cm
σ_{cor} = water surface tension salinity correction, dynes/cm
σ_{do} = dead oil surface tension, dynes/cm
σ_{go} = live oil surface tension, dynes/cm
μ = viscosity, cp

Subscripts
HC = hydrocarbon
H2S = hydrogen sulfide
CO2 = carbon dioxide
N2 = nitrogen

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Appendix A

Correlations used to estimate the required properties used for liquid loading calculations are provided in this Appendix. A new method was developed to estimate the surface tension between gas and water which is more accurate than existing methods.

Gas Density

The real gas equation can be rearranged to solve for density as follows:

$$\rho_g = \frac{p\,\gamma_g\,M_a}{Z\,R\,T_{\circ R}} \quad \text{(A1)}$$

The calculation of Z factor requires the evaluation of pseudocritical properties as outlined by Sutton[22]. Standing[19] provided details on the proper estimation of pseudocritical properties for natural gases containing nonhydrocarbons. Failure to follow these guidelines will result in excessive error in calculated Z. The hydrocarbon portion of the total gas gravity and the hydrocarbon gas gravity is determined by backing out the nonhydrocarbon contribution to the total.

$$y_{HC} = 1 - y_{H_2S} - y_{CO_2} - y_{N_2} \quad \text{(A2)}$$

$$\gamma_{gHC} = \frac{\gamma_g - \left(y_{H_2S}M_{H_2S} + y_{CO_2}M_{CO_2} + y_{N_2}M_{N_2}\right)/M_a}{y_{HC}} \quad \text{(A3)}$$

where the molecular weights and critical properties for the nonhydrocarbon components are provided below:

Component	Mole Weight	P_c, psia	T_c, °R
Air	28.964	NA	NA
Hydrogen Sulfide	34.08	1070.6	672.4
Carbon Dioxide	44.01	1306.0	547.6
Nitrogen	28.016	493.0	227.3

Table A1 – Nonhydrocarbon component properties

For light gas and gas-condensate systems, the hydrocarbon pseudocritical properties are calculated from the following equations.

$$p_{pcHC} = 744 - 125.4\,\gamma_{gHC} + 5.9\,\gamma_{gHC}^2 \quad \text{(A4)}$$

$$T_{pcHC} = 164.3 + 357.7\,\gamma_{gHC} - 67.7\,\gamma_{gHC}^2 \quad \text{(A5)}$$

Hydrocarbon pseudocritical properties are modified as follows to account for the nonhydrocarbon components.

$$p_{pc}^* = y_{HC}\,p_{pcHC} + y_{H_2S}\,p_{cH_2S} + y_{CO_2}\,p_{cCO_2} + y_{N_2}\,p_{cN_2} \quad \text{(A6)}$$

$$T_{pc}^* = y_{HC}\,T_{pcHC} + y_{H_2S}\,T_{cH_2S} + y_{CO_2}\,T_{cCO_2} + y_{N_2}\,T_{cN_2} \quad \text{(A7)}$$

Wichert and Aziz[28] determined that pseudocritical properties must be further modified as follows to account for the presence of hydrogen sulfide and carbon dioxide in the gas.

$$\varepsilon = 120\left[\left(y_{CO_2} + y_{H_2S}\right)^{0.9} - \left(y_{CO_2} + y_{H_2S}\right)^{1.6}\right] + 15\left(y_{H_2S}^{0.5} - y_{H_2S}^{4}\right) \quad \text{(A8)}$$

$$T_{pc} = T_{pc}^* - \varepsilon \quad \text{(A9)}$$

$$p_{pc} = \frac{p_{pc}^*\left(T_{pc}^* - \varepsilon\right)}{T_{pc}^* + y_{H_2S}\left(1 - y_{H_2S}\right)\varepsilon} \quad \text{(A10)}$$

These values of pseudocritical pressure and temperature are then used to calculate the pseudo reduced pressure and temperature as follows.

$$p_{pr} = \frac{p}{p_{pc}} \quad \text{(A11)}$$

$$T_{pr} = \frac{T}{T_{pc}} \quad \text{(A12)}$$

The Z factor is then determined using methods such as Dranchuk and Abou-Kassem which accurately represent the Standing-Katz Z factor chart.

$$Z = f\left(p_{pr}, T_{pr}\right) \quad \text{(A13)}$$

Water Density

The general equation for calculating water density is given by Eqn A14.

$$\rho_w = \frac{0.999012\,\gamma_w + 0.000218\,\gamma_g\,R_s}{B_w} \quad \text{(A14)}$$

For pure water assuming no dissolved gas, this equation reduces to

$$\rho_w = \frac{0.999012}{B_w} \quad \text{(A15)}$$

The water formation volume factor can be accurately defined using a method proposed by Rowe and Chou[16].

$$A_0 = 5.916365 - 0.01035794\,T_{\circ K} + 0.9270048\times10^{-5}\,T_{\circ K}^2 - \frac{1127.522}{T_{\circ K}} + \frac{100674.1}{T_{\circ K}^2} \quad \text{(A16)}$$

$$A_1 = -\,2.5166 \;+\; 0.0111766\,T_{\circ K} - 0.170552\times10^{-4}\,T_{\circ K}^2 \quad \text{(A17)}$$

$$A_2 = 2.84851 - 0.0154305\,T_{\circ K} + 0.223982\times10^{-4}\,T_{\circ K}^2 \quad \text{(A18)}$$

The density of the water at standard pressure, the temperature of interest and without dissolved gas is defined

$$\rho_w^o = \left(A_0 + A_1\,w_s + A_2\,w_s^2\right)^{-1} \quad \text{(A19)}$$

The water density is also determined at standard pressure and temperature using Eqns. A16-A19. The water formation volume factor (FVF) is determined from these results using Eqn. A20. It should be noted that these equation use salinity fraction. Salinity is often expressed with units of parts per million (ppm). The percent salinity is then ppm/10,000 and factional salinity is ppm/1,000,000.

$$B_{w(p_{sc},T)}^o = \frac{\rho_{w(p_{sc},T_{sc})}}{\rho_{w(p_{sc},T)}^o} \quad \text{(A20)}$$

The water FVF corrected for elevated pressure is given by Eqns. A21-A23.

$$A_0 = 10^6\left(0.314 + 0.58\,w_s + 1.9\times10^{-4}\,T_{\circ F} - 1.45\times10^{-6}\,T_{\circ F}^2\right) \quad \text{(A21)}$$

$$A_1 = 8 + 50\,w_s - 0.125\,w_s\,T_{\circ F} \quad \text{(A22)}$$

$$B_w = B_{w(p_{sc},T)}^o\left(1 + \frac{A_1}{A_0}\,p\right)^{\left(-1/A_1\right)} \quad \text{(A23)}$$

For conditions with pressure less than 5000 psia and temperatures ranging from 60-250 °F, the error for this method applied to pure water is very low and ranges from -0.05% to 0.07%.

Condensate Density

Glasø's[9] equation for volatile oil can be used to estimate gas dissolved in free condensate

$$p_b^* = 10^{\left[2.886856 - \sqrt{14.18112 - 3.309286\log\left(p_b\right)}\right]} \quad \text{(A24)}$$

$$R_s = \gamma_g\left[p_b^*\left(\frac{\gamma_{API}^{0.989}}{T_{\circ F}^{0.130}}\right)\right]^{1.22549} \quad \text{(A25)}$$

The condensate formation volume factor can be estimated using Glasø's method

$$B_{ob}^* = R_s\left(\frac{\gamma_g}{\gamma_o}\right)^{0.526} + \;0.968\,T_{\circ F} \quad \text{(A26)}$$

$$\log\left(B_{ob} - 1\right) = -\,6.58511 + 2.91329\log B_{ob}^* - 0.27683\left(\log B_{ob}^*\right)^2 \quad \text{(A26)}$$

The density can then be calculated from

$$\rho_o = \frac{0.999012\,\gamma_o + 0.000218\,\gamma_g\;R_s}{B_o} \quad \text{(A27)}$$

Condensate-Gas Surface Tension

In 2000, Abdul-Majeed[1] presented a method to calculate the surface tension of gas-oil systems. Surface tension data from 18 crude oils covering the temperature range 60 to 130°F was used to derive Eqn. A28.

$$\sigma_{od} = \left(1.17013 - 1.694\times10^{-3}\, T_{\circ F}\right)\left(38.085 - 0.259\,\gamma_{API}\right) \quad \text{(A28)}$$

Data acquired from 42 crude oil/gas systems was used to develop the live oil correction factor which is represented by the following equation.

$$\left(\frac{\sigma_{go}}{\sigma_{od}}\right) = 0.056379 + 0.94362\, e^{\left(-3.8491\times10^{-3} R_s\right)} \quad \text{(A29)}$$

Surface tension is then the product of these two equations. Application of Eqns. A28-A29 and Glasø's volatile oil equations for solution gas-oil ratio were checked against Abdul-Majeed's data representative of a condensate (e.g. API>40). Results show an average error of -12.6%, an average absolute error of 12.9% with a standard deviation of 8.5.

Water-Gas Surface Tension

In 1988, Firoozabadi and Ramey[8] presented a correlation to estimate the surface tension between hydrocarbons and water. Equations fitted to the original correlation were developed in separate works by Danesh[7] and Sutton[21]. The equation developed by Danesh did not accurately represent the original data so Sutton[22] developed an improved correlation. In both cases, subsequent use of the correlation resulted in a poor representation of water-gas surface tension. Therefore, the original data used by Firoozabadi and Ramey was gathered and supplemented with recently published measurements for pure water and a variety of pure hydrocarbons: methane, ethane, propane, i-butane, n-butane, pentane, hexane, heptane, octane, nonane, decane, undecane, dodecane, tetradecane, hexadecane, benzene and toluene. Problems with data measurements have been identified by other researchers centering on equipment used for the measurement or excessive solubility of the hydrocarbon phase in the water phase and these data were eliminated. The final data set consisted of 1512 points which covered the following properties.

Property	Minimum	Maximum
Pressure, psia	14.7	43,526
Temperature, °F	35.6	391.7
Surface tension, dynes/cm	15.6	75.5
Water Density, g/cc	0.878	1.094
Hydrocarbon density, g/cc	0.00044	0.989

Table A2 – Description of surface tension database

A nonlinear regression routine was developed to minimize the error between the measured and calculated surface tension. An accurate relationship for gas-water surface tension was derived resulting in the following equation[23].

$$\sigma_{gw} = \left[\left(1.53988 + \frac{2.08339}{\rho_{w_{g/cc}} - \rho_{h_{g/cc}}}\right)\left(\frac{T_{\circ R}}{T_c}\right)^{\left(0.821976 - 1.83785\times10^{-3}\, T_{\circ R} + 1.34016\times10^{-6}\, T_{\circ R}^2\right)}\left(\rho_{w_{g/cc}} - \rho_{h_{g/cc}}\right)\right]^{3.6667} \quad \text{(A30)}$$

with the provision that for gases a constant value of 302.881 is used in place of critical temperature. A statistical comparison of the methods is provided in Table A3.

Method	# Pts	% AE	Std Dev	% AAE	Std Dev	>10% Error Count
Gas Only						
Danesh	787	48.2	72.6	65.2	57.8	667
Sutton 2006	787	60.3	84.3	75.8	70.6	632
Sutton 2009	787	0.5	4.8	3.4	3.4	43
Methane Only						
Danesh	407	-14.1	7.2	14.2	7.0	287
Sutton 2006	407	-12.4	9.9	13.4	8.4	252
Sutton 2009	407	-1.1	4.7	3.5	3.4	19
Natural Gas with CO_2						
Danesh	91	-2.4	8.6	7.4	5.0	29
Sutton 2006	91	-6.7	10.2	10.1	7.1	40
Sutton 2009	91	2.3	7.8	6.2	5.5	14
Natural Gas with N_2						
Danesh	103	-27.4	8.6	27.4	8.4	97
Sutton 2006	103	-28.2	8.0	28.2	8.0	101
Sutton 2009	103	-1.9	8.4	6.3	5.8	23

Table A3 – Accuracy of water-gas surface tension relationships

In order to test the suitability of the method, data consisting of carbon dioxide-natural gas and nitrogen-natural mixtures was evaluated. The results, also summarized in Table A3, illustrate the viability of the new method.

The water density used in Eqn. A30 is for pure water adjusted for pressure and temperature effects. Most oil field waters contain dissolved salt. The following equation derived from a graph by Standing[27] provides a suitable correction for brines. The correction is additive to the surface tension derived for pure water.

$$\sigma_{cor} = 3.44 \times 10^{-5} C_s \quad \text{(A31)}$$

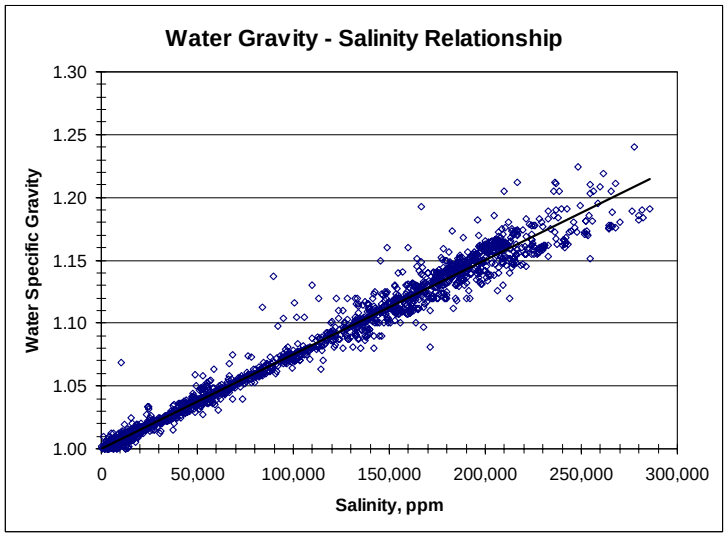

Fig. 1 – Salinity-specific gravity relationship for formation brines

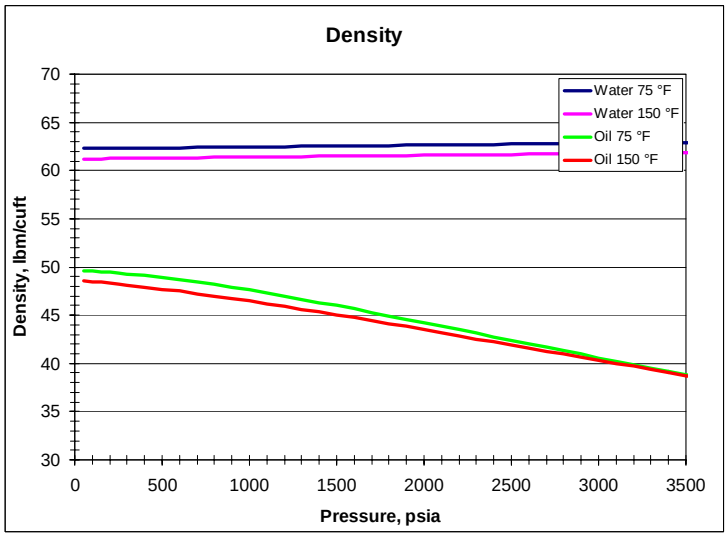

Fig. 2 – Effect of pressure and temperature on condensate and water density

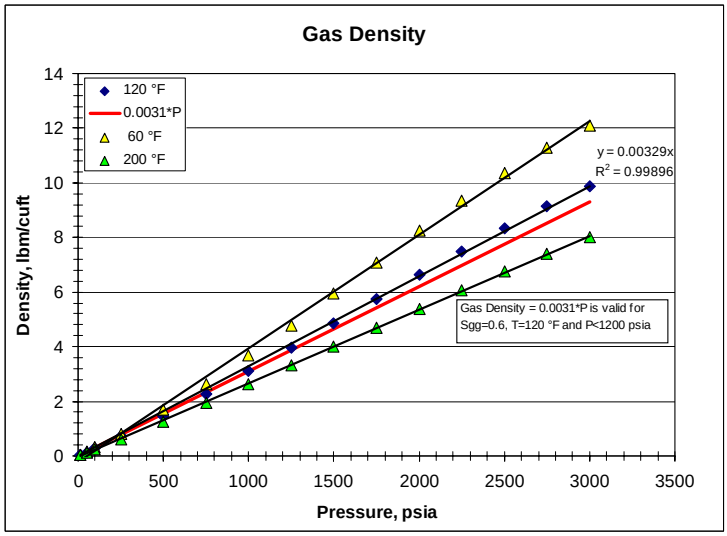

Fig. 3 – Simple gas density relationship

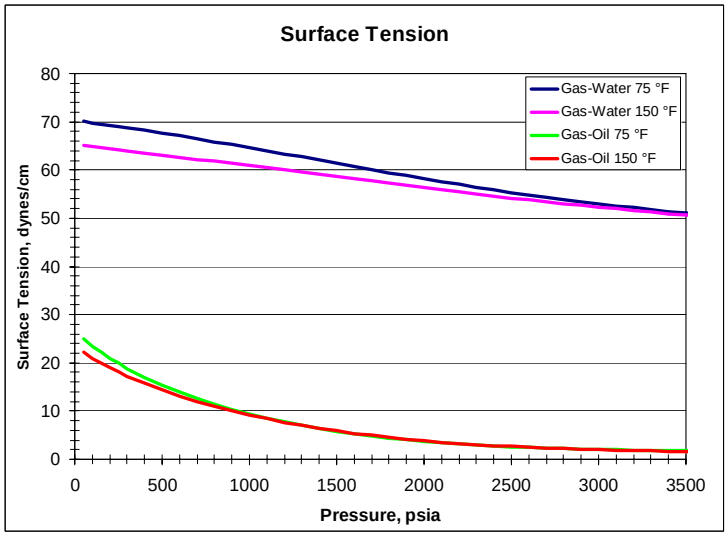

Fig. 4 - Effect of pressure and temperature on condensate-gas and water-gas surface tension

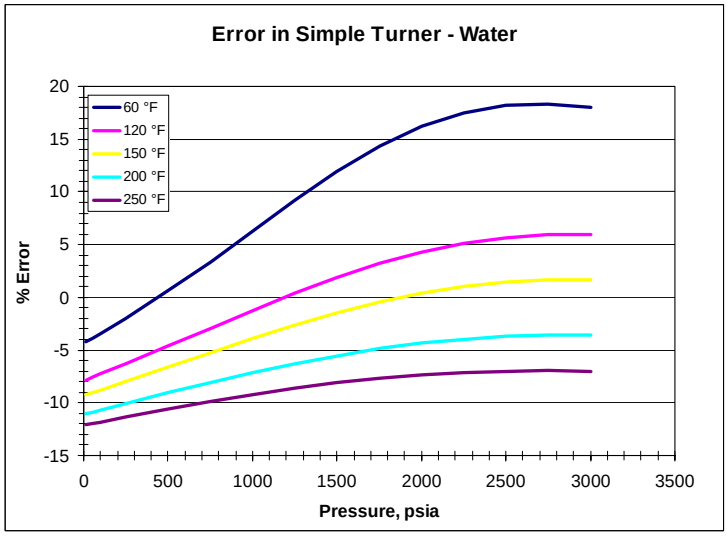

Fig. 5 – Error in the simplified form of Turner's equation (water)

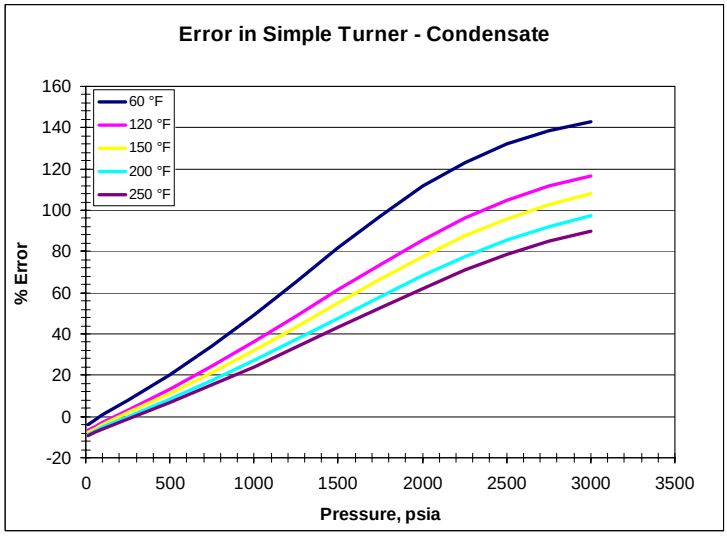

Fig. 6 – Error in the simplified form of Turner's equation (condensate)

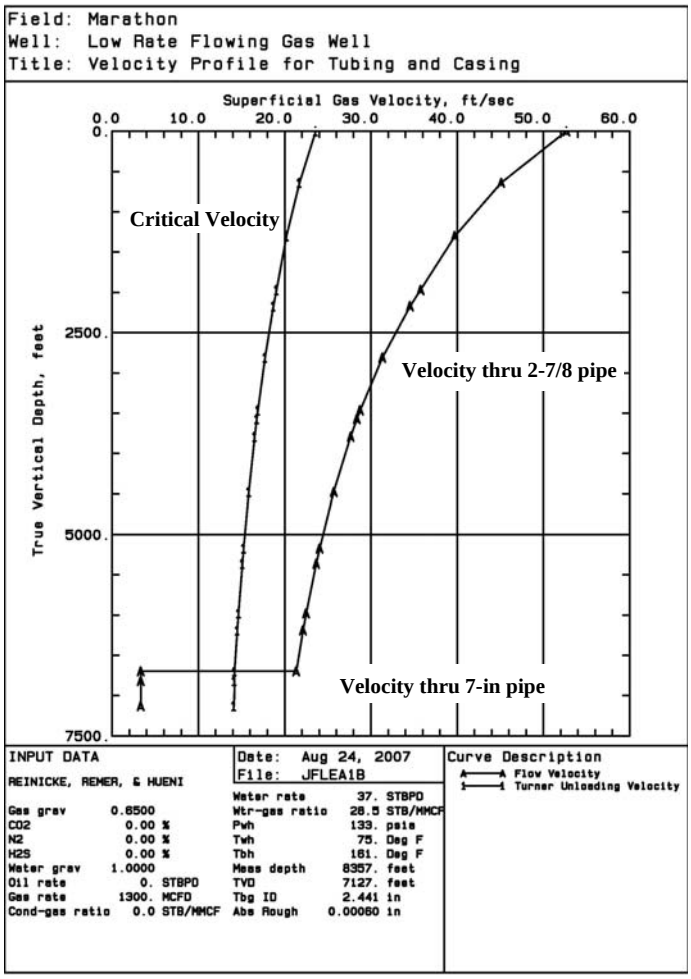

Fig. 7 – Velocity profile for well with changing geometry

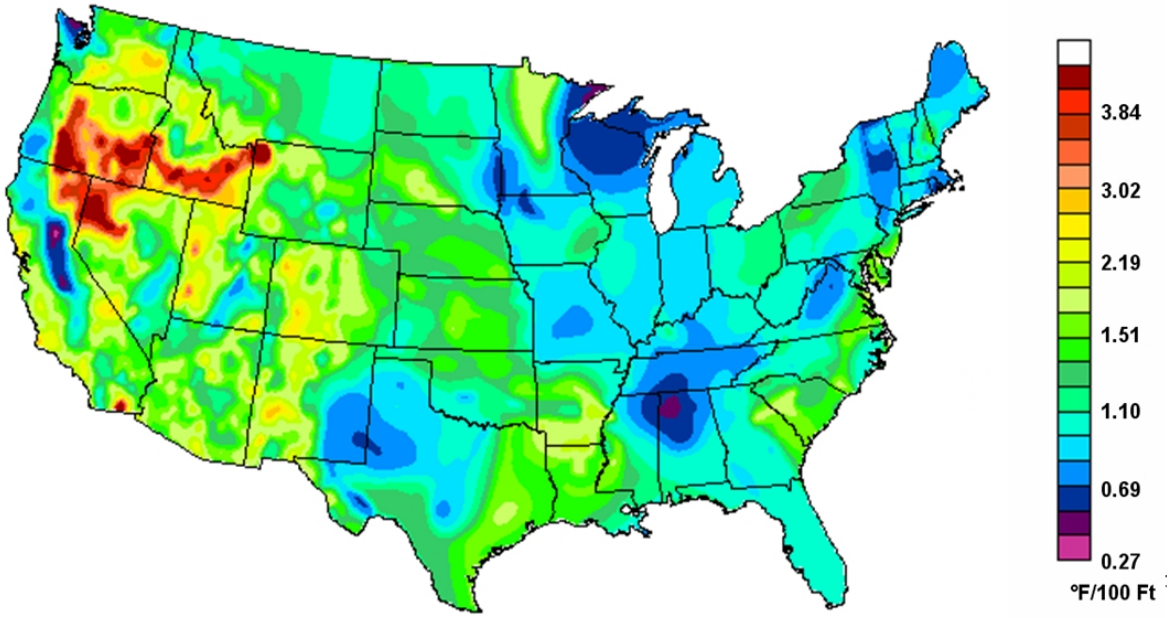

Fig. 8 – Geothermal gradient map of the United States[18]

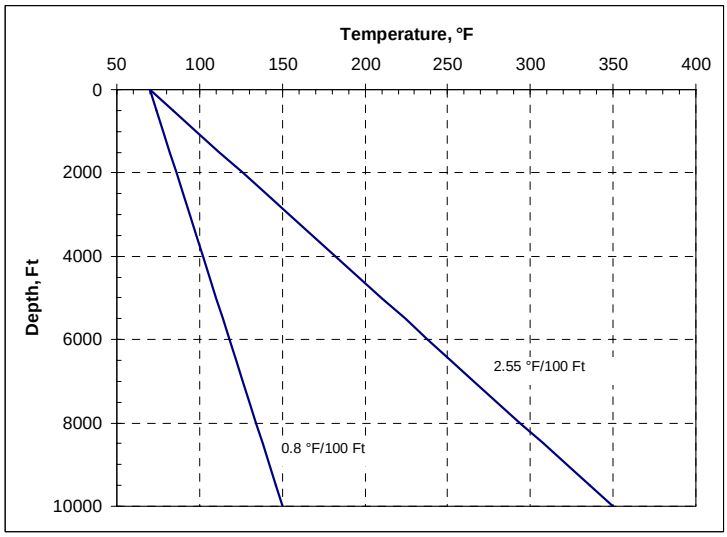

Fig. 9 – Temperature profile

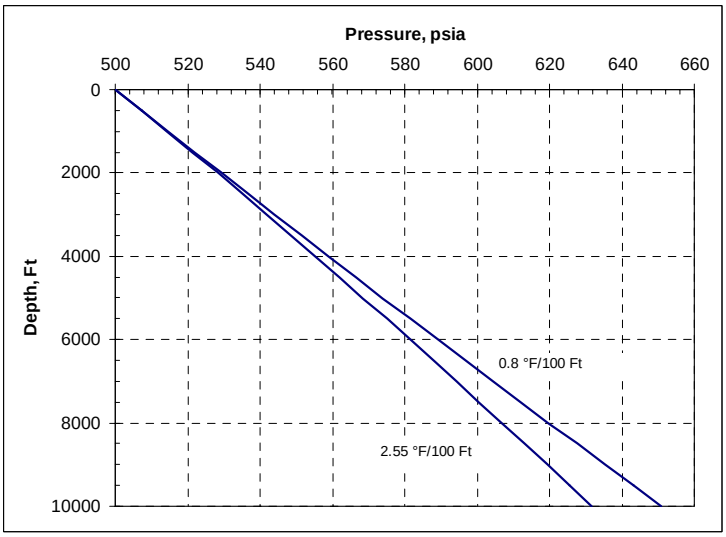

Fig. 10 – Pressure profile

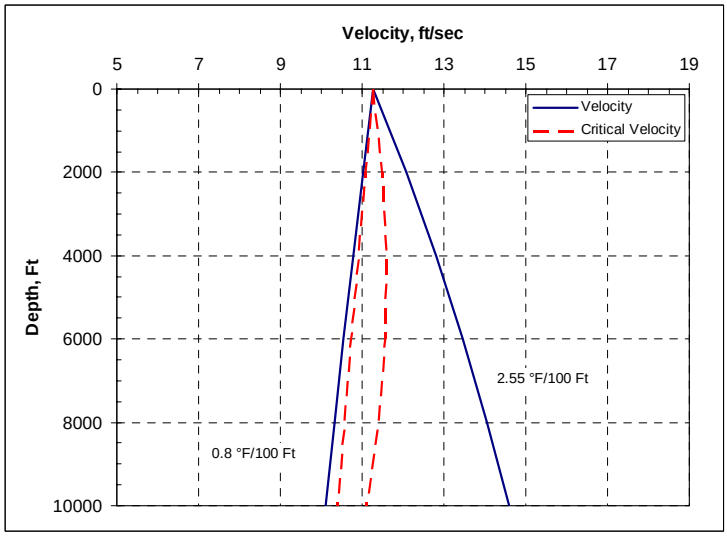

Fig. 11 – Velocity profile

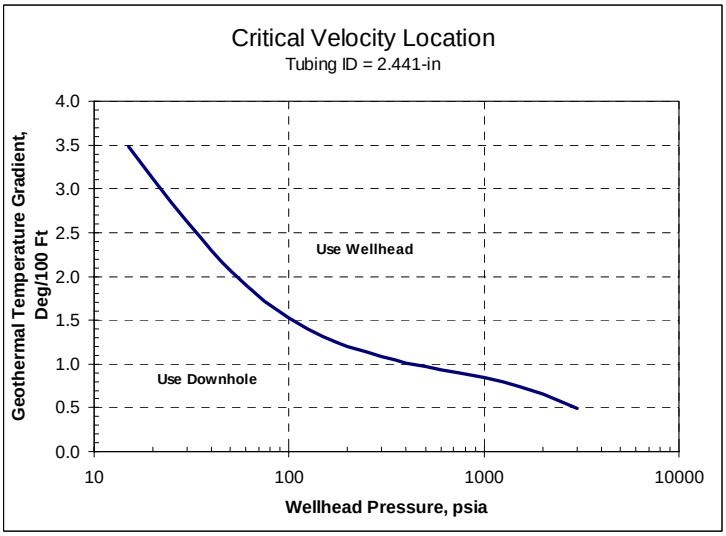

Fig. 12 – Boundary for Turner critical velocity evaluation (dry gas calculation)

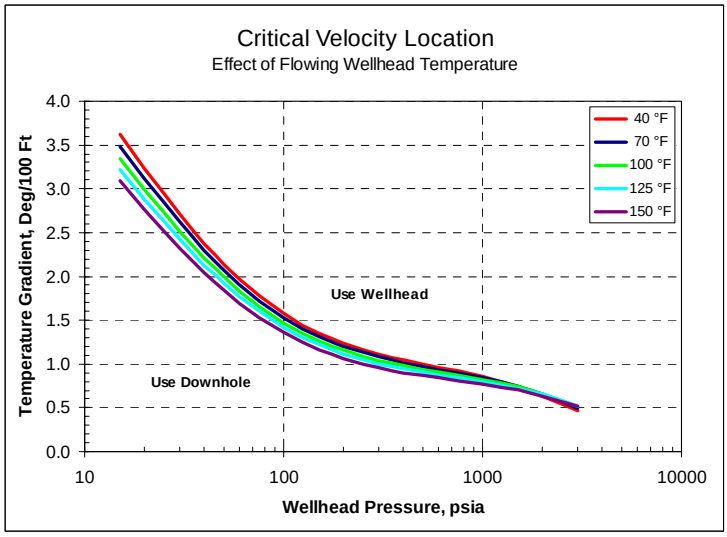

Fig. 13 – Boundary for Turner critical velocity evaluation (variable wellhead temperature)

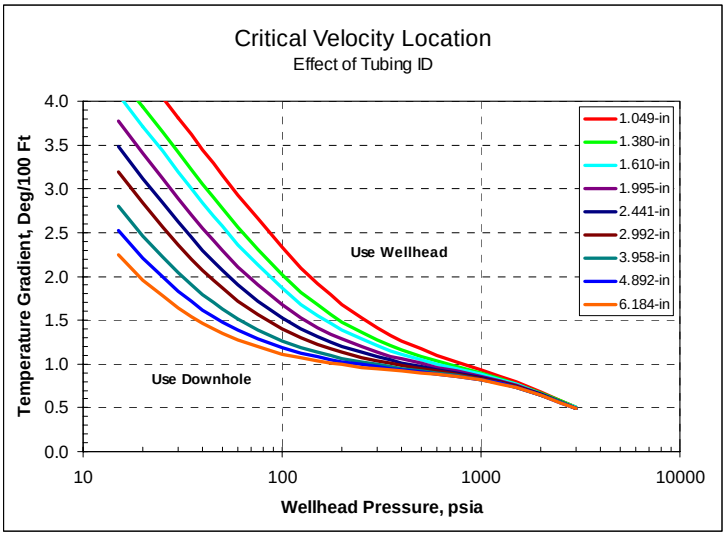

Fig. 14 - Boundary for Turner critical velocity evaluation (variable tubing diameter)

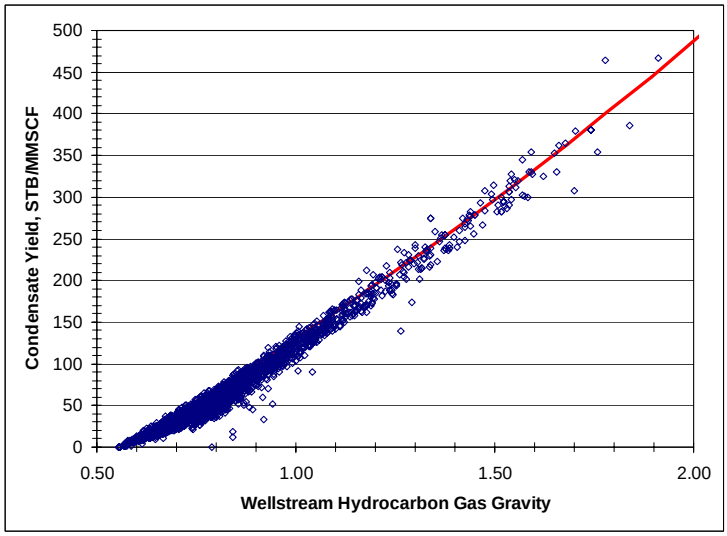

Fig. 15 – Gas-condensate yield vs wellstream gravity

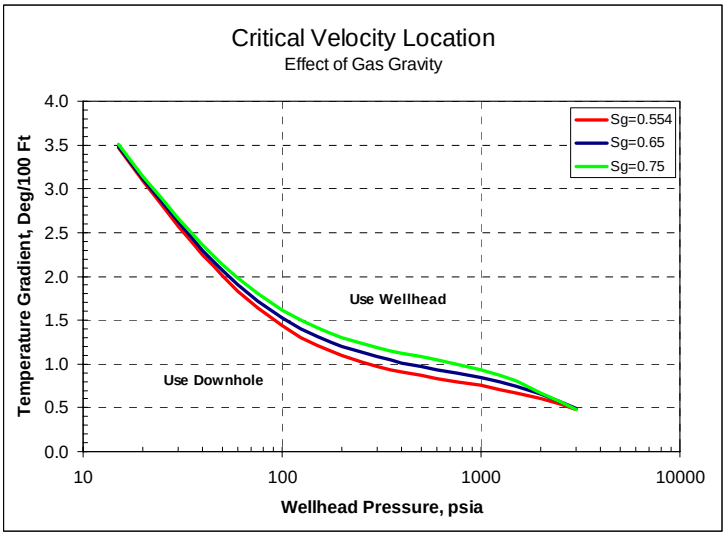

Fig. 16 - Boundary for Turner critical velocity evaluation (variable gas gravity)

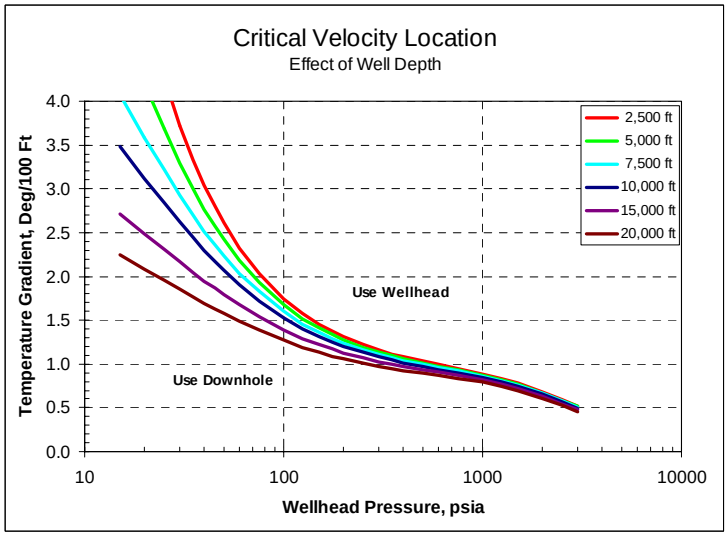

Fig. 17 - Boundary for Turner critical velocity evaluation (variable well depth)

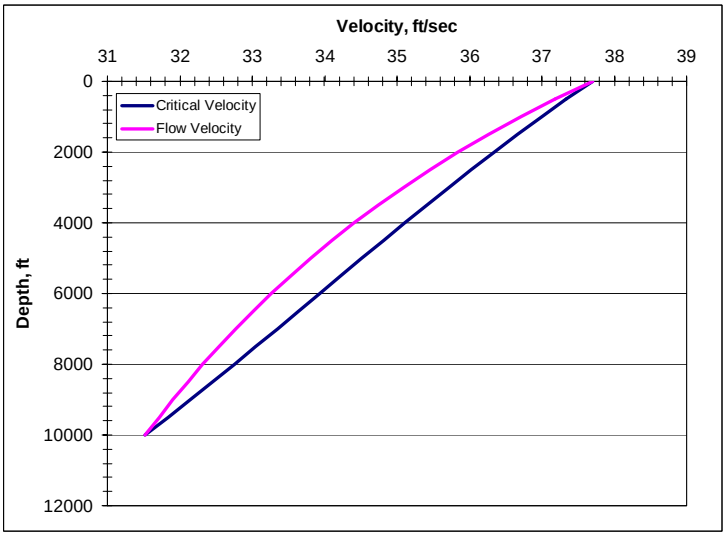

Fig. 18 – Critical velocity and flow velocity profile for balanced condition flow rate

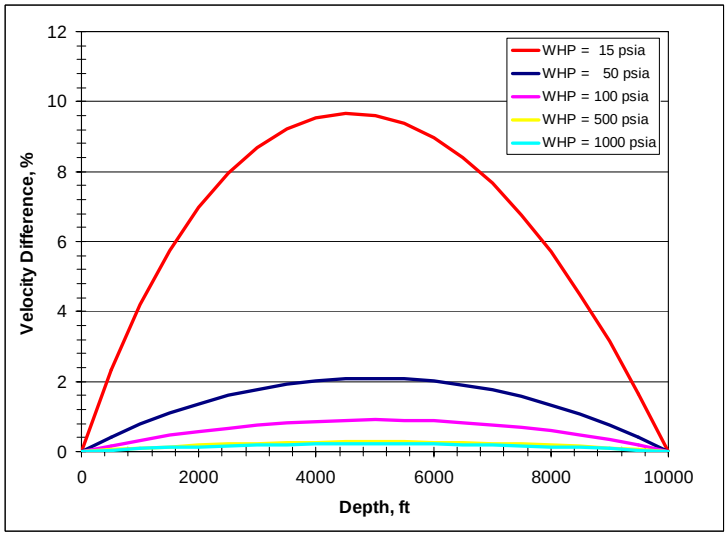

Fig. 19 – Difference between critical velocity and flow velocity for balanced condition flow rate

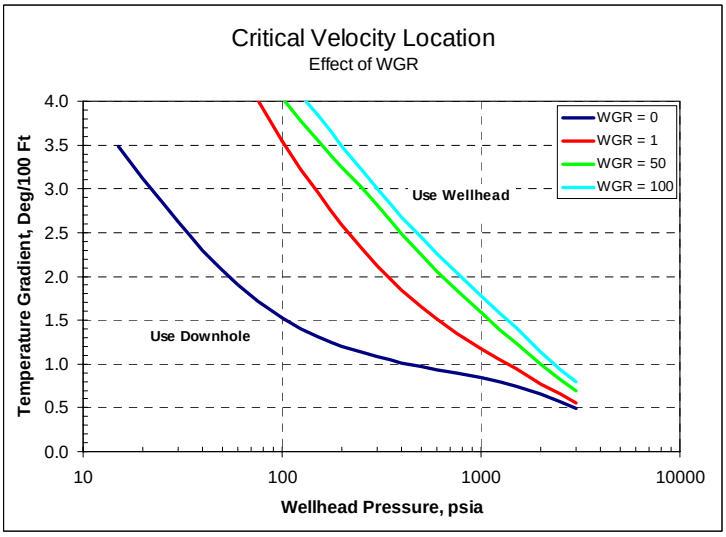

Fig. 20 - Boundary for Turner critical velocity evaluation (variable water-gas ratio)

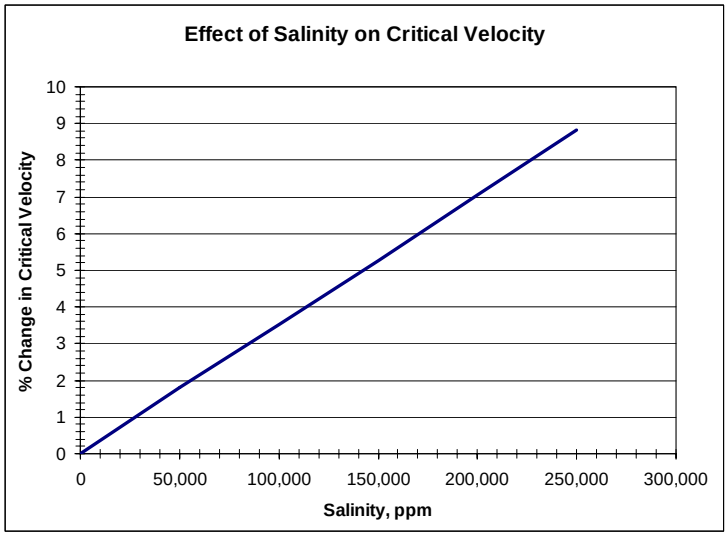

Fig. 21 – Change in critical velocity with change in water salinity

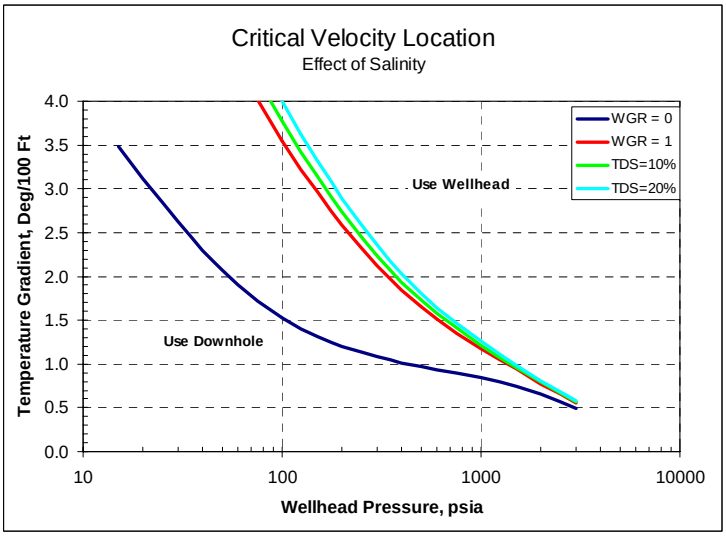

Fig. 22 – Boundary for Turner critical velocity evaluation (variable water salinity)

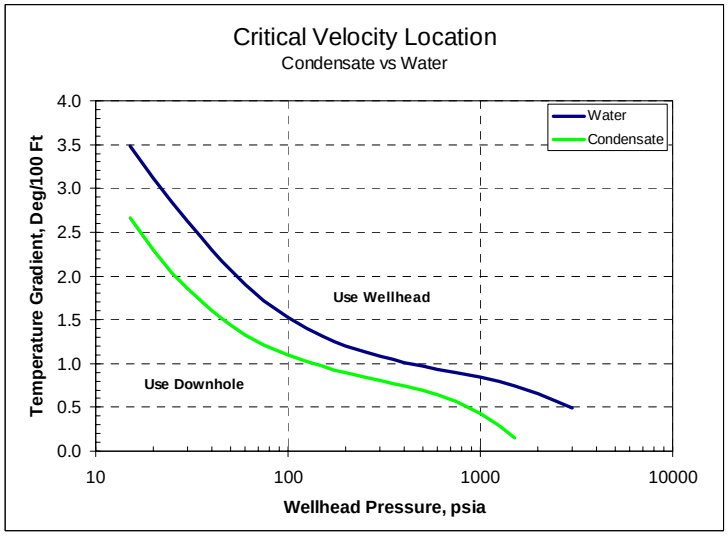

Fig. 23 – Boundary for Turner critical velocity evaluation for gas condensate

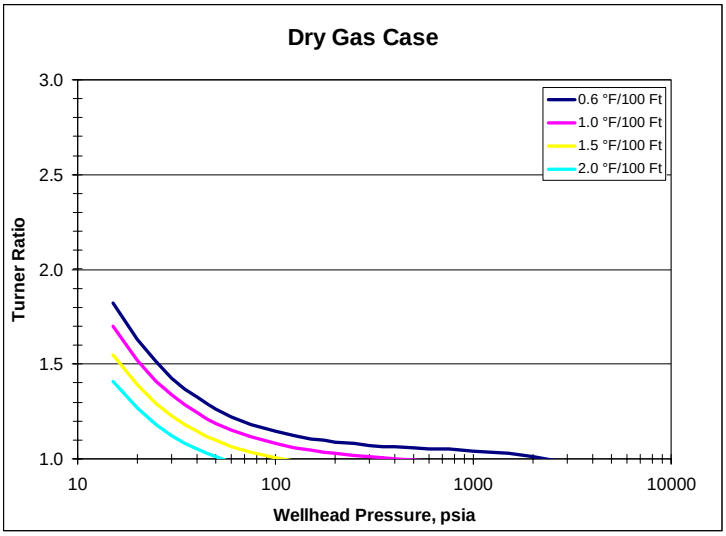

Fig. 24 – Turner ratio (variable temperature gradient)

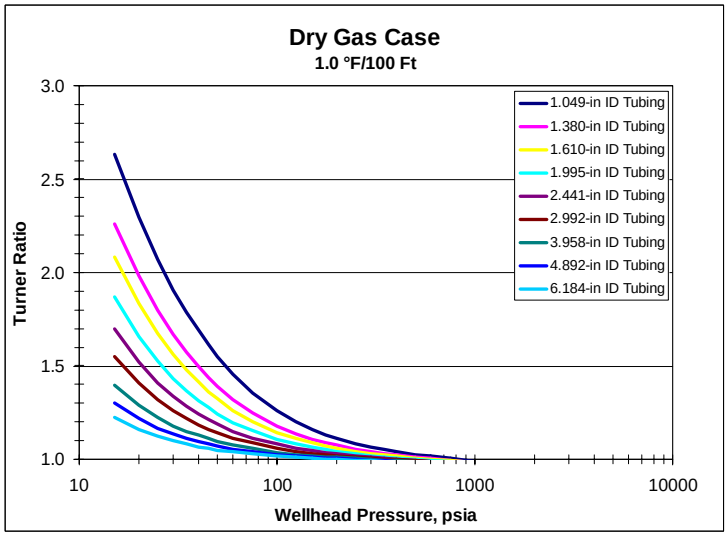

Fig. 25 – Turner ratio (variable tubing diameter)

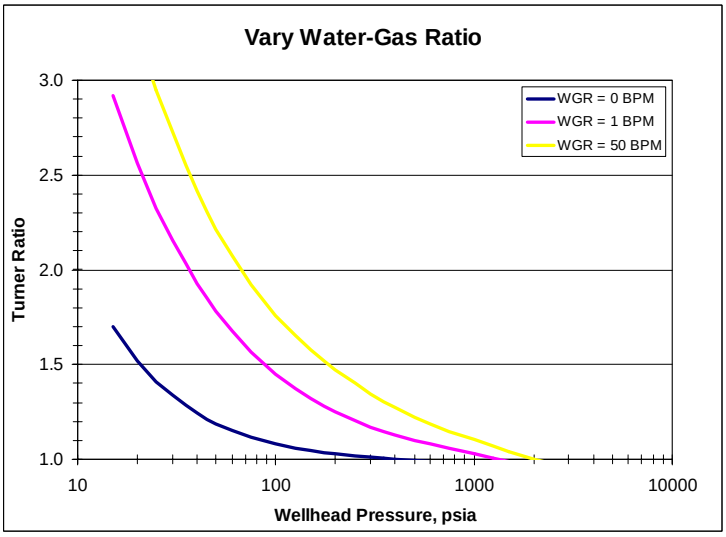

Fig. 26 – Turner ratio (variable water-gas ratio)

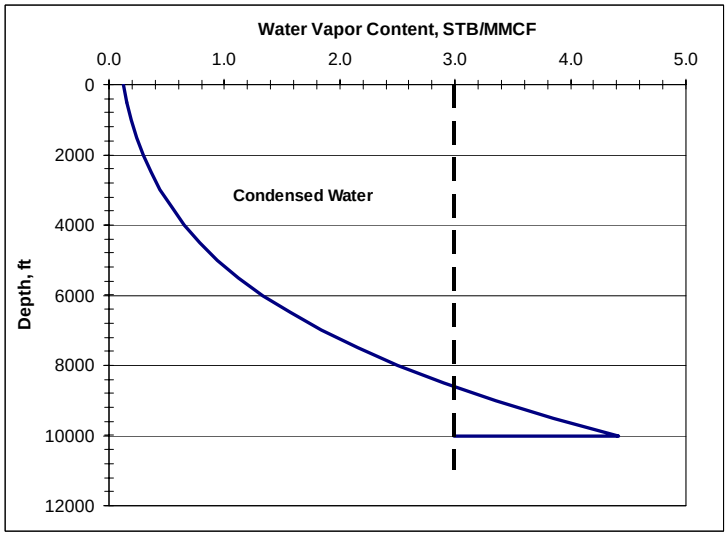

Fig. 27 – Gas water vapor content with depth (Example 1)

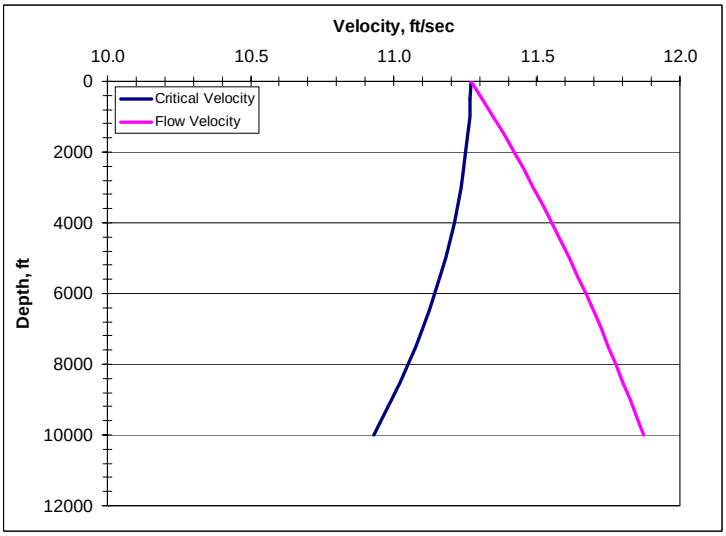

Fig. 28 – Flow velocity and critical velocity profiles with depth (Example 1)

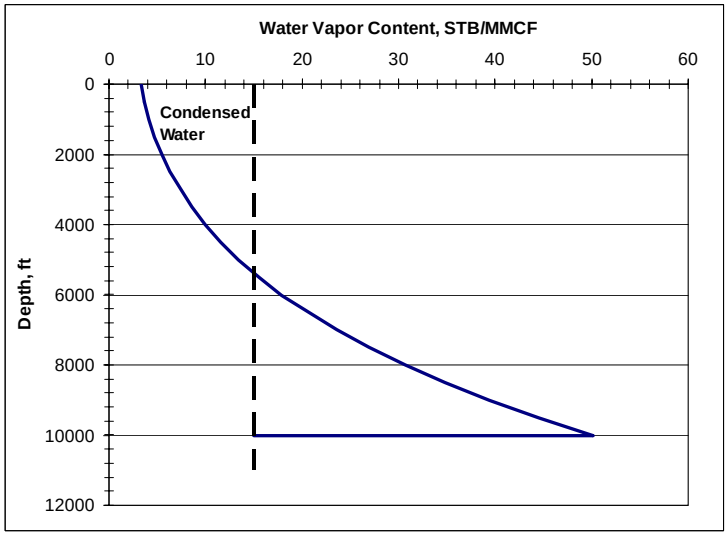

Fig. 29 – Gas water vapor content with depth (Example 2)

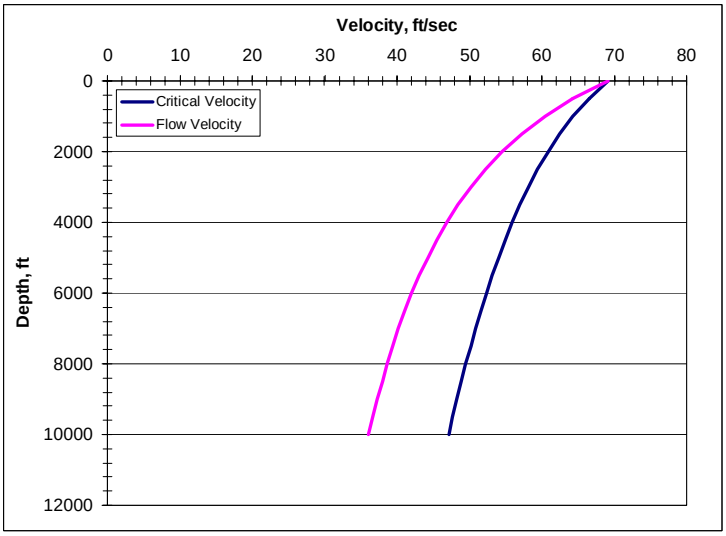

Fig. 30 – Flow velocity and critical velocity profiles with depth using rate determined from wellhead conditions (Example 2)

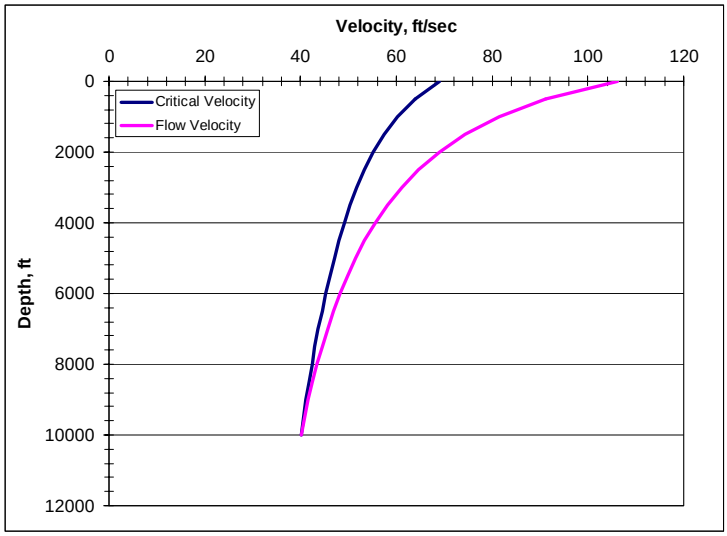

Fig. 31 – Flow velocity and critical velocity profiles with depth using rate determined from wellhead conditions and Turner ratio (Example 2)