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Validation of the Cullender and Smith Method for Determining Pressure Loss in the Tubing of Gas Wells

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ABSTRACT

The ability of the reservoir to deliver a certain quantity of gas depends both on the inflow performance relationship and the flowing bottom hole pressure. In order to determine the deliverability of the total well system, it is necessary to calculate all the parameters and pressure drops, one of which in the tubing. Calculation of pressure loss in the tubing is a very important parameter in the stability of fluid flow from the reservoir to the surface.
The calculation of pressure loss in the tubing which is most widely used in the field is the Cullender and Smith Method. The purpose of this study is to validate why the Cullender and Smith method is most widely used in the field to determine the pressure loss in the tubing compared to other pressure loss in tubing methods.
The methodology used in this study is calculating the pressure loss in the tubing with the Average Temperature and Deviation Factor Method, the Sukkar and Cornel Method, and the Cullender and Smith Method. After calculating the pressure loss in the tubing using each of these methods, then comparing the percent error of the calculation method with the results in the well. The data used in the calculation is the data from the MZ Field from 7 wells in the East Kalimantan area.
The results of the average error percentage obtained from this study are the Average and Deviation Factor Method is 5.38%, the Sukkar and Cornell Method is 5.65%, and the Cullender and Smith Method is 3.83%. From this study, it can be said that the Cullender and Smith Method to be valid or the most accurate method for used in the field compared to other methods due to resulting the smallest percent error from the calculation.

Keywords: gas wells; pressure loss; pressure loss in the tubing

I. INTRODUCTION

The ability of the reservoir to deliver a certain quantity of gas depends both on the inflow performance relationship and the flowing bottom hole pressure. In order to determine the deliverability of the total well system, it is necessary to calculate all the parameters and pressure drops, one of which in the tubing. The method used in determining the pressure loss in the tubing can be determined in several ways. The selection of these methods is adjusted to the conditions of the production wells, especially gas production wells in this study.

In this study field which consists of 7 (seven) wells, the calculation of the pressure loss will be presented only using the Cullender and Smith Method. This method is a method that is most widely used in the field for the calculation of determining the pressure loss in the tubing. So that the purpose of this study is to validate why the Cullender and Smith method is most widely used in the field to determine the pressure loss in the tubing compared to other pressure loss in tubing methods.

The approach used in determining the pressure loss in the tubing in gas wells is based on the concept of the Law of Conservation of Energy. The calculation method used is to calculate the pressure loss using the Average Temperature and Deviation Factor Method, Sukkar and Cornel Method, and Cullender and Smith Method. After performing calculations with each of these methods, a comparison of the flowing bottom hole pressure calculated from each method will be carried out with the flowing bottom hole pressure measured in the field.

Calculation of pressure loss in the tubing is a very important parameter in the stability of fluid flow from the reservoir to the surface. It is important to calculate the pressure loss in the tubing using the right calculation method. The calculation of pressure loss in the tubing which is most widely used in the field is the Cullender and Smith Method. This study will validate whether the Cullender and Smith Method is the most accurate method or is the method with the smallest percent error when compared to other pressure loss calculation methods.

The approach used in determining the pressure loss in the tubing based on the General Flow Equations. These general flow equations, based on the mechanical energy balance, contain no assumptions regarding temperature and can be used with either straight line or curved temperature gradients. Although these general flow equations are solved by numerical means, the methods are as convenient as many of those used today to calculate pressures in gas wells and pipelines. These numerical methods are illustrated for flowing and static columns of gas in wells and for flow in pipelines. The friction factors recommended in this study are based on an absolute roughness of 0.0006 in.

II. METHODS

The methodology used in this study is calculating the pressure loss in the tubing with the Average Temperature and Deviation Factor Method, the Sukkar and Cornel Method, and the Cullender and Smith Method (shown in flowchart **Figure 1**). After calculating the pressure loss in the tubing using each of these methods, then comparing the percent error of the calculation method with the results in the well. The data used in the calculation is the data from the MZ Field in the East Kalimantan area.

The following are step by step for calculating the pressure loss in the tubing using the Average Temperature and Deviation Factor Method:

1. Assume the P_{wf}.
2. Calculate average pressure ($\bar{P}$), psia, where $\bar{P} = \frac{(P_{wf}+P_{tf})}{2}$ *(1)*
   and average temperature ($\bar{T}$), °R, where $\bar{T} = \frac{(T_{wf}+T_{tf})}{2}$ *(2)*
3. Calculate pseudo critical pressure (P_{pc}), where $P_{pc} = 709.6 - 58.7\ \gamma_g$ *(3)*
   for natural gas.
4. Calculate pseudo reduce pressure (P_{pr}), where $P_{pr} = \frac{\bar{P}}{P_{pc}}$ *(4)*
5. Calculate pseudo critical temperature (T_{pc}), where $T_{pc} = 170.5 + 307.3\ \gamma_g$ *(5)*
   for natural gas.
6. Calculate pseudo reduce temperature (T_{pr}), where $T_{pr} = \frac{\bar{T}}{T_{pc}}$ *(6)*
7. Calculate gas deviation factor ($\bar{z}$), is a function of P_{pr} and T_{pr}.
8. Calculate average gas viscosity ($\bar{\mu}_g$), cp. Using Lee Correlation.
9. Calculate Reynold Number (N_{Re}), where $N_{Re} = 20011 \frac{q\,(MMscfd)\,\gamma}{\mu\,(cp)\,D\,(in)}$ *(7)*
   and calculate $\frac{e}{D}$.
10. Calculate Moody friction factor ($\bar{f}$), is a function of N_{Re} and $\frac{e}{D}$. Obtained from Moody graph or using Nikuradse Correlation or Jain Correlation.
11. Calculate length of flow string or tubing (L), ft, where $L = \frac{H}{\cos\theta}$ *(8)*
    For vertical well, L = H or Z.
12. Calculate P_{wf} using equation $P_{wf}^2 = P_{tf}^2\, e^s + \frac{25\,\gamma_g \bar{T}\,\bar{z}\,\bar{f}\,L\,(e^s-1)\,q^2}{s\,D^5}$ *(9)*,
    where P_{tf} is flowing well head pressure, psia, $s = \frac{2\,\gamma_g\,Z}{53.34\,\bar{T}\,\bar{z}}$ *(10)*,
    and Z is vertical distance of reservoir from surface, ft.
13. Comparing the assumed P_{wf} with the calculated P_{wf}, if Abs $= \left(\frac{\text{Assumed } P_{wf} - \text{Calculated } P_{wf}}{P_{wf}}\right) \leq$ tolerance, then the calculation is complete, where $P_{wf} = P_{wf}$ assumed. If it is greater than the tolerance, then return to step one (1) with the assumed P_{wf} = calculated P_{wf}.
14. Calculate pressure loss in the tubing (ΔP_{tubing}) using $P_{wf} - P_{tf}$.

The following are step by step for calculating the pressure loss in the tubing using the Sukkar and Cornel Method (applies only to vertical wells):

1. Calculate the log average temperature ($\bar{T}$), °R, where $\bar{T} = \frac{T_{wf}-T_{tf}}{ln\frac{T_{wf}}{T_{tf}}}$ *(11)*

2. Calculate the pseudo critical temperature (T_{pc}), °R, where $T_{pc} = 170.5 + 307.3\,\gamma_g$ *(12)*
3. Calculate pseudo reduce temperature (T_{pr}), where $T_{pr} = \frac{\bar{T}}{T_{pc}}$ *(13)*
4. Calculate pseudo critical pressure (P_{pc}), where $P_{pc} = 709.6 - 58.7\,\gamma_g$ *(14)*
5. Calculate Moody friction factor ($\bar{f}$), is a function of N_{Re} and $\frac{e}{D}$. Obtained from Moody graph or using Nikuradse Correlation or Jain Correlation.
6. Calculate B, where $B = \frac{667\,\bar{f}\,q_{sc}^2\,\bar{T}^2}{D^2\,P_{pc}^2\,cos\theta}$ *(15)*
7. Calculate $(P_{tf})_r$, where $\left(P_{tf}\right)_r = \frac{P_{tf}}{P_{pc}}$ *(16)*
8. By knowing the value of B, T_{pr}, and P_{pr}, then determine the value of $\int_{(P_{tf})_r}^{(P_{wf})_r} I(P_r)dP_r$, where $\int_{(P_{tf})_r}^{(P_{wf})_r} I(P_r)dP_r = \int_{0.2}^{(P_{wf})_r} I(P_r)dP_r - \int_{0.2}^{(P_{tf})_r} I(P_r)dP_r$ *(17)*
   The integral value of 0.2 may be evaluated from any arbitrary lower limit.
   Then $\int_{0.2}^{(P_{wf})_r} I(P_r)dP_r = \int_{0.2}^{(P_{tf})_r} I(P_r)dP_r + \frac{\gamma_g\,Z}{53.34\,\bar{T}}$ *(18)*
   The integral value can be found using the Sukkar and Cornel table.
9. Calculate the value of $\frac{\gamma_g\,Z}{53.34\,\bar{T}}$ *(19)*
10. Sum up the calculated value in step nine (9) with the integral value calculated in step eight (8). The result will be the same as the right side of the equation step eight (8).
11. From the value of T_{pr} and the right-hand side of the equation step (8) in step (10), then using the Sukkar and Cornel table we obtain the value of $(P_{wf})_r$ (if the value does not exist, it can be interpolated).
12. Calculate the P_{wf}, psia, where $P_{wf} = \left(P_{wf}\right)_r\,(P_{pc})$ *(20)*
13. Calculate pressure loss in the tubing *(ΔP_{tubing}) using $P_{wf} - P_{tf}$* *(21)*

The following are step by step for calculating the pressure loss in the tubing using the Cullender and Smith Method:

1. Calculate the midpoint temperature value (T_{mf}), °R, where $T_{mf} = \frac{T_{tf}+T_{wf}}{2}$ *(22)*
2. Calculate the pseudo critical temperature (T_{pc}), °R, where $T_{pc} = 170.5 + 307.3\,\gamma_g$ *(23)*
3. Calculate T_{pr} at well head, midpoint, and bottom hole using equation:
   Well head: $T_{pr} = \frac{T_{tf}}{T_{pc}}$ *(24)*
   Midpoint: $T_{pr} = \frac{T_{mf}}{T_{pc}}$ *(25)*
   Bottom hole: $T_{pr} = \frac{T_{wf}}{T_{pc}}$ *(26)*
4. Calculate pseudo critical pressure (P_{pc}) use **Equation (14)**.
5. Calculate P_{pr} at well head, where $P_{pr} = \frac{P_{tf}}{P_{pc}}$ *(27)*
6. Calculate F using equation $F = \frac{0.10796\,q_{sc}}{D^{2.612}}$ *for D < 4.227 in* *(28)*
   and $F = \frac{0.10337\,q_{sc}}{D^{2.582}}$ *for D > 4.227 in* *(29).*
   Or it can be obtained using **Cullender and Smith table**.
7. Calculate z factor at well head (z_{tf}), as a function of P_{pr} and T_{pr} from gas deviation factor for natural gases (z-chart) as can be seen in **Figure 2**.
8. Calculate length of tubing (L), ft.
9. Calculate I_{tf} at well head conditions, where $I_{tf} = \frac{\frac{P}{T\,z}}{F^2 + \frac{1}{1000}\frac{z}{L}\left(\frac{P}{T\,z}\right)^2}$ *(30)*
   and $F^2 = \frac{2.665(f/4)q_{sc}^2}{D^5}$ *(31)*
10. Assume $I_{mf} = I_{tf}$ for the conditions at the average well depth or at the midpoint of the flow string or tubing.
11. Calculate P_{mf}, where $37.5\,\gamma_g\,\frac{z}{2} = (P_{mf} - P_{tf})(I_{mf} + I_{tf})$ *(31).*
12. Calculate P_{pr} at midpoint using equation $P_{pr} = \frac{P_{mf}}{P_{pc}}$ *(32).*

13. Calculate z factor at midpoint (z_{mf}), as a function of P_{pr} and T_{pr} from z-chart.
14. Calculate I at midpoint (I_{mf}) with the same equation in step nine (9).
15. Calculate P_{mf} with the equation step (11) using the I_{mf} calculated in step fourteen (14).
16. Comparing the assumed P_{mf} with the calculated P_{mf}. If the difference is greater than 1 psi, then the calculation returns to step twelve (12) with the assumed P_{mf} = calculated P_{mf}. If the difference is less than 1 psi, then $P_{mf} = P_{mf}$ assumption.
17. Assume $I_{wf} = I_{mf}$ for the conditions at the bottom of the flow string or tubing.
18. Calculate P_{wf} for the bottom of the flow string or tubing, where $37.5\ \gamma_g \frac{z}{2} = (P_{wf} - P_{mf})(I_{wf} + I_{mf})$ *(33).*
19. Calculate P_{pr} at the bottom of the flow string or tubing where $P_{pr} = \frac{P_{wf}}{P_{pc}}$ *(34)*
20. Calculate z factor at the bottom of the flow string or tubing (z_{wf}), as a function of P_{pr} and T_{pr} from z-chart on **Figure 2**.
21. Calculate I at the bottom of the flow string or tubing (I_{wf}) with the same equation in step nine (9).
22. Calculate P_{wf} using the same equation in step eighteen (18).
23. Comparing the assumed P_{wf} with the calculated P_{wf}. If the difference is greater than 1 psi, then the calculation returns to step nineteen (19) with the assumed P_{wf} = calculated P_{wf}. If the difference is less than 1 psi, then $P_{wf} = P_{wf}$ assumption.
24. Calculate pressure loss in the tubing (ΔP_{tubing}) using $P_{wf} - P_{tf}$.

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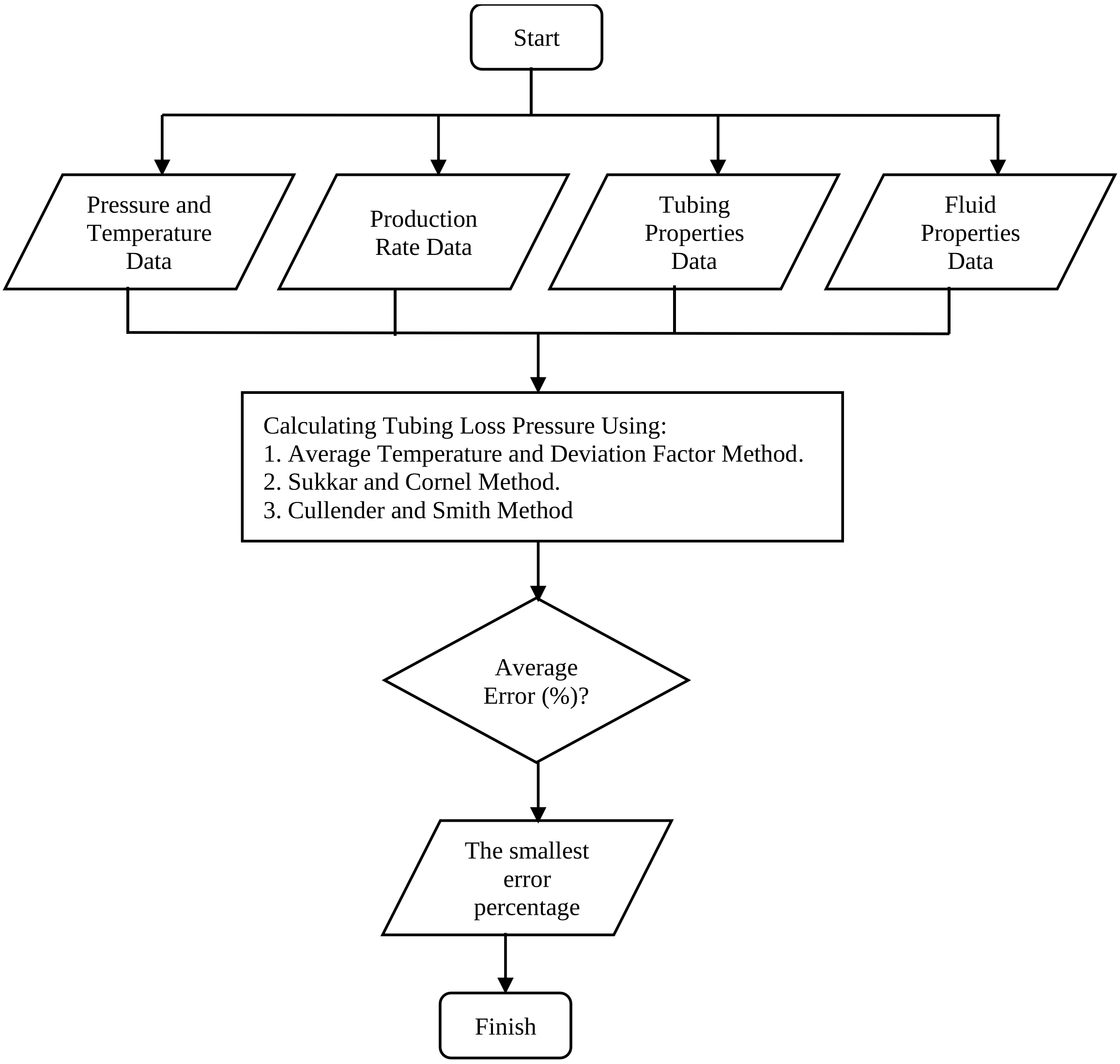

Figure 1. Flowchart Validation Tubing Loss Pressure

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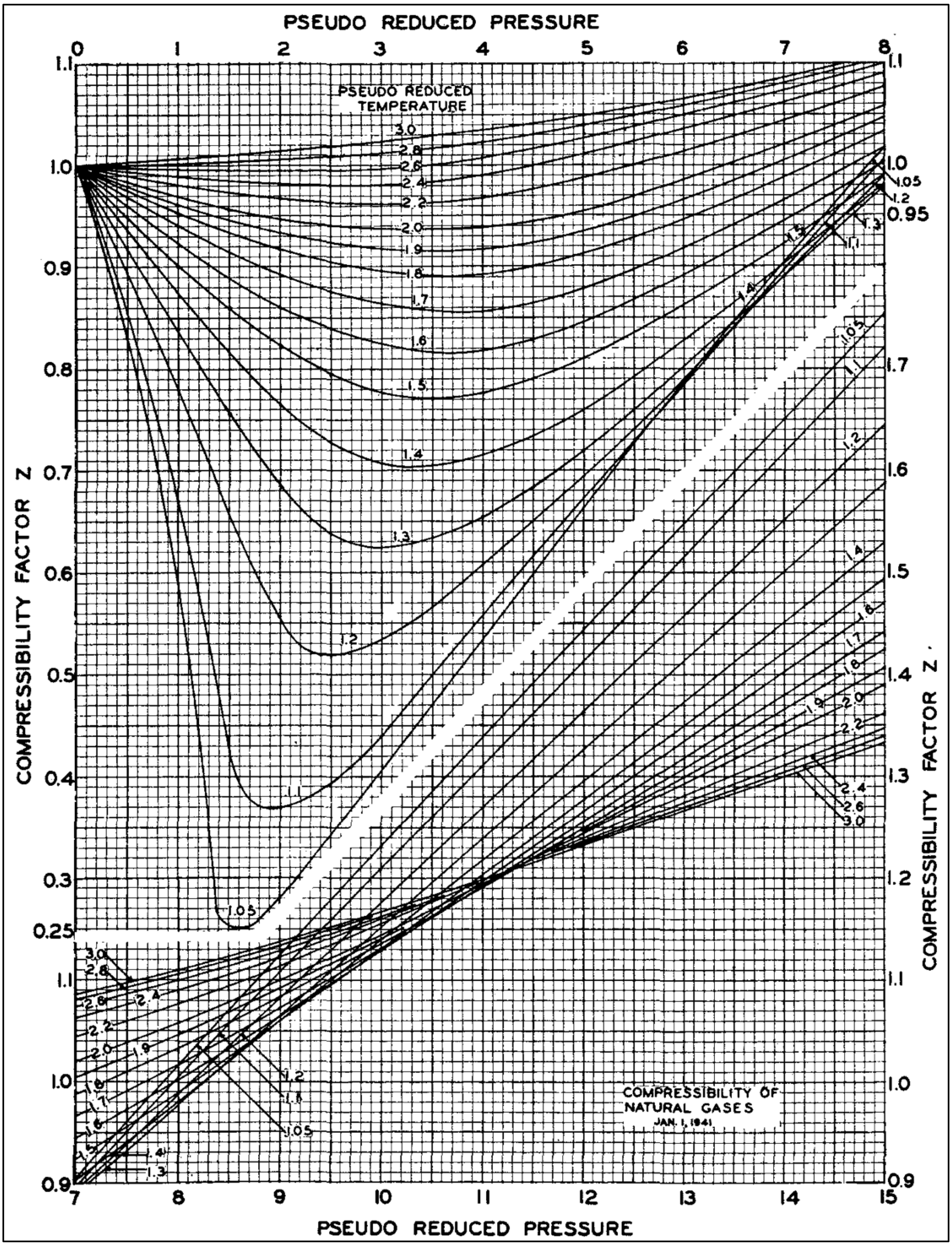

Figure 2. Compressibility Factor
(M. B. Standing and D. L. Katz, 1942)

III. RESULTS AND DISCUSSION

The data used in calculating the pressure loss in the tubing is taken from 7 (seven) gas production wells in the MZ Field in East Kalimantan area. The gas production wells used are Z-01, Z-02, Z-03, Z-04, Z-05, Z-06, and Z-07. We can see the data for each well in the MZ Field in **Table 1** below. While the field data needed in the analysis of the calculation of the pressure loss in the tubing are:

1. Flowing well head pressure (P_{tf}), psia.
2. Flowing well head temperature (T_{tf}), °R.
3. Flowing bottom hole temperature (T_{wf}), °R.
4. Specific gravity of gas (γ_g).
5. Gas flow rate (q_g), MMscfd at 14.65 psia and 60°F.
6. Length of flow string (L), ft.
7. Angle of well from vertical (θ), degree.
8. Inside diameter of tubing (I.D), inch.
9. Pipe absolute roughness (e), inch.

Table 1. MZ Field Gas Well Data

Well Name	q_g, MMscfd	I.D tubing, in	SG of gas	L tubing, ft	P_{wf} (measured), psia	P_{tf}, psia	T_{wf}, °F	T_{tf}, °F
Z-01	4.20	1.995	0.746	13904	2170	1345	278	121
Z-02	7.75	2.992	0.718	10730	2518	1812	207	110
Z-03	3.11	1.995	0.755	11682	1942	1383	240	121
Z-04	12.85	2.992	0.7	12464	3114	2235	257	128
Z-05	3.50	1.995	0.7	12523	1838	1240	246	128
Z-06	2.61	2.992	0.78	12716	2061	1455	260	121
Z-07	2.91	2.992	0.693	12854	2347	1786	276	121

An example of calculating the pressure loss in the tubing in this study is using the Cullender and Smith Method. An example of the calculation of pressure loss is carried out at Well Z-01 and then the results will be compared with the results of calculations with other methods we can see in **Table 2**. The calculation of the pressure loss in the tubing using the Cullender and Smith Method at Well Z-01 is first carried out by calculating the well flowing bottom hole pressure (P_{wf}), where the difference between the well flowing bottom hole pressure (P_{wf}) and the flowing well head pressure (P_{tf}) is the calculated pressure loss in the tubing.

By calculating the pressure loss in the tubing with these three methods, then comparing the measured pressure loss in the actual tubing conditions so that the percent error between calculations and measurements is obtained. The measured pressure loss in the tubing is the differences between the flowing bottom hole pressure measured in field conditions and the measured at the flowing well head pressure.

The following is an example results of the calculation of pressure loss in the tubing using the Cullender and Smith Method from the Z-01 Well data:

1. Calculate T_{mf}.

$$T_{mf} = \frac{T_{tf} + T_{wf}}{2} = \frac{(581 + 738)°R}{2} = 659.5\ °R$$

2. Calculate T_{pc}.

$$T_{pc} = 170.5 + 307.3\,\gamma_g = 170.5 + 307.3\,(0.746) = 399.75\ °R$$

3. Calculate T_{pr}.
   At well head:

$$T_{pr} = \frac{T_{tf}}{T_{pc}} = \frac{581\ °R}{399.75\ °R} = 1.45$$

   At midpoint:

$$T_{pr} = \frac{T_{mf}}{T_{pc}} = \frac{659.5\ °R}{399.75\ °R} = 1.65$$

At bottom hole:

$$T_{pr} = \frac{T_{wf}}{T_{pc}} = \frac{738\ °R}{399.75\ °R} = 1.85$$

4. Calculate P_{pc}.

$$P_{pc} = 709.6 - 58.7\ \gamma_g = 709.6 - 58.7\ (0.746) = 665.81$$

5. Calculate P_{pr} at well head.

$$P_{pr} = \frac{P_{tf}}{P_{pc}} = \frac{1345}{665.81} = 2.02$$

6. D = 1.995 in < 4.277 in.

$$F = \frac{0.10796\ q_{sc}}{D^{2.612}} = \frac{0.10796\ (4.2)}{1.995^{2.612}} = 0.0746$$

$$F^2 = 5.573\ \times 10^{-3}$$

7. From T_{pr} = 1.45 at well head and P_{pr} = 2.02, determine z_{tf} from gas deviation factor chart (z-chart). z_{tf} = 0.80.

8. Calculate L. L = 13904 ft.

9. Calculate I_{tf} at well head.

$$I_{tf} = \frac{\dfrac{P_{tf}}{T_{tf}\ (z_{tf})}}{F^2 + \dfrac{1}{1000}\ \dfrac{z}{L}\left(\dfrac{P_{tf}}{T_{tf}\ (z_{tf})}\right)^2} = \frac{\dfrac{1345}{581\ (0.80)}}{5.573 \times 10^{-3} + \dfrac{1}{1000}\ \dfrac{13904}{13904}\left(\dfrac{1345}{581\ (0.80)}\right)^2}$$

$$I_{tf} = 207.44$$

10. Assume $I_{mf} = I_{tf}$ = 207.44.

11. Calculate P_{mf}.

$$37.5\ \gamma_g \frac{z}{2} = (P_{mf} - P_{tf})(I_{mf} + I_{tf})$$

$$37.5\ (0.746) \frac{13904}{2} = (P_{mf} - 1345)(207.44 + 207.44)$$

$$P_{mf} = 1813.77\ \text{psia}$$

12. Calculate P_{pr} at midpoint.

$$P_{pr} = \frac{P_{mf}}{P_{pc}} = \frac{1813.77}{665.81} = 2.72$$

13. From T_{pr} = 1.65 at midpoint and P_{pr} = 2.72, determine z_{mf} from gas deviation factor chart (z-chart). z_{mf} = 0.86.

14. Calculate I_{mf} at midpoint.

$$I_{mf} = \frac{\frac{P_{mf}}{T_{mf}\,(z_{mf})}}{F^2 + \frac{1}{1000}\frac{z}{L}\left(\frac{P_{mf}}{T_{mf}\,(z_{mf})}\right)^2} = \frac{\frac{1813.77}{659.5\,(0.86)}}{5.573 \times 10^{-3} + \frac{1}{1000}\frac{13904}{13904}\left(\frac{1813.77}{659.5\,(0.86)}\right)^2}$$

$$I_{mf} = 202.36$$

15. Calculate P_{mf}.

$$37.5\,\gamma_g \frac{z}{2} = (P_{mf} - P_{tf})(I_{mf} + I_{tf})$$

$$37.5\,(0.746)\frac{13904}{2} = (P_{mf} - 1345)(202.36 + 207.44)$$

$$P_{mf} = 1819.58 \text{ psia}$$

16. Comparing the assumed P_{mf} with the calculated P_{mf}. The difference is greater than 1 psi, then the calculation returns to step (12).
    Calculate P_{pr} at midpoint.

$$P_{pr} = \frac{P_{mf}}{P_{pc}} = \frac{1819.58}{665.81} = 2.73$$

From T_{pr} = 1.65 at midpoint and P_{pr} = 2.73, determine z_{mf} from gas deviation factor chart (z-chart). z_{mf} = 0.86.

Calculate I_{mf} at midpoint.

$$I_{mf} = \frac{\frac{P_{mf}}{T_{mf}\,(z_{mf})}}{F^2 + \frac{1}{1000}\frac{z}{L}\left(\frac{P_{mf}}{T_{mf}\,(z_{mf})}\right)^2}$$

$$I_{mf} = \frac{\frac{1819.58}{659.5\,(0.86)}}{5.573 \times 10^{-3} + \frac{1}{1000}\frac{13904}{13904}\left(\frac{1819.58}{659.5\,(0.86)}\right)^2}$$

$$I_{mf} = 202.17$$

Calculate P_{mf}.

$$37.5\,\gamma_g \frac{z}{2} = (P_{mf} - P_{tf})(I_{mf} + I_{tf})$$

$$37.5\,(0.746)\frac{13904}{2} = (P_{mf} - 1345)(202.17 + 207.44)$$

$$P_{mf} = 1819.80 \text{ psia}$$

17. Assume $I_{wf} = I_{mf}$ = 202.17.

18. Calculate P_{wf}.

$$37.5\,\gamma_g \frac{z}{2} = (P_{wf} - P_{mf})(I_{wf} + I_{mf})$$

$$37.5\,(0.746)\frac{13904}{2} = (P_{wf} - 1819.80)(202.17 + 202.17)$$

$$P_{wf} = 2300.78 \text{ psia}$$

19. Calculate P_{pr} at bottom hole.

$$P_{pr} = \frac{P_{wf}}{P_{pc}} = \frac{2300.78}{665.81} = 3.45$$

20. From T_{pr} = 1.85 at bottom hole and P_{pr} = 3.45, determine z_{wf} from gas deviation factor chart (z-chart). z_{wf} = 0.90.

21. Calculate I_{wf}.

$$I_{wf} = \frac{\frac{P_{wf}}{T_{wf}\,(z_{wf})}}{F^2 + \frac{1}{1000}\frac{z}{L}\left(\frac{P_{wf}}{T_{wf}\,(z_{wf})}\right)^2} = \frac{\frac{2300.78}{738\,(0.90)}}{5.573 \times 10^{-3} + \frac{1}{1000}\frac{13904}{13904}\left(\frac{2300.78}{738\,(0.90)}\right)^2}$$

$$I_{wf} = 188.15$$

22. Calculate P_{wf}.

$$37.5\,\gamma_g \frac{z}{2} = (P_{wf} - P_{mf})(I_{wf} + I_{mf})$$

$$37.5\,(0.746)\frac{13904}{2} = (P_{wf} - 1819.80)(188.15 + 202.17)$$

$$P_{wf} = 2318.06 \text{ psia}$$

23. Comparing the assumed P_{wf} with the calculated P_{wf}. The difference is greater than 1 psi, then the calculation returns to step (16).
Calculate P_{pr} at bottom hole.

$$P_{pr} = \frac{P_{wf}}{P_{pc}} = \frac{2318.06}{665.81} = 3.48$$

From T_{pr} = 1.85 at bottom hole and P_{pr} = 3.48, determine z_{wf} from gas deviation factor chart (z-chart). z_{wf} = 0.89.

Calculate I_{wf}.

$$I_{wf} = \frac{\frac{P_{wf}}{T_{wf}\,(z_{wf})}}{F^2 + \frac{1}{1000}\frac{z}{L}\left(\frac{P_{wf}}{T_{wf}\,(z_{wf})}\right)^2} = \frac{\frac{2318.06}{738\,(0.89)}}{5.573 \times 10^{-3} + \frac{1}{1000}\frac{13904}{13904}\left(\frac{2318.06}{738\,(0.89)}\right)^2}$$

$$I_{wf} = 187.2$$

Calculate P_{wf}.

$$37.5\,\gamma_g \frac{z}{2} = (P_{wf} - P_{mf})(I_{wf} + I_{mf})$$

$$37.5\,(0.746)\frac{13904}{2} = (P_{wf} - 1819.80)(187.2 + 202.17)$$

$$P_{wf} = 2319.28 \text{ psia}$$

24. Calculate ΔP_{tubing}.

$$\Delta P_{tubing} = P_{wf} - P_{tf} = 2318 - 1345 = 973 \text{ psia}$$

The same calculation conducted on other wells which can be seen at **Table 2** below.

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Table 2. Calculation Result on All Wells

Well Name	Pwf measured (psia)	Ptf (psia)	Pwf calculated			Pressure Loss measured (psia)	Pressure Loss calculated (psia)			Error (percent)		
			Average Temp and Deviation Factor	Sukkar and Cornell	Cullender and Smith		Average Temp and Deviation Factor	Sukkar and Cornell	Cullender and Smith	Average Temp and Deviation Factor	Sukkar and Cornell	Cullender and Smith
Z-01	2170	1345	2322	2131	2318	825	977	786	973	7.00	1.80	6.82
Z-02	2518	1812	2597	2654	2507	706	785	842	695	3.14	5.40	0.44
Z-03	1942	1383	2106	2111	2072	559	723	728	689	8.43	8.70	6.69
Z-04	3114	2235	3019	3252	3243	879	784	1017	1008	3.05	4.43	4.14
Z-05	1838	1240	1939	2003	1925	598	699	763	685	5.50	8.98	4.73
Z-06	2061	1455	2100	1980	2080	606	645	525	625	1.91	3.93	0.92
Z-07	2347	1786	2550	2495	2419	561	764	555	633	8.65	6.31	3.07
Average error (percent)										5.38	5.65	3.83

Pressure loss measured is a difference between P_{wf} measured and P_{tf}. For example, pressure loss measured on Well Z-01 is:

$$\Delta P_{measured} = (P_{wf})_{measured} - P_{tf} = 2170 - 1345 = 825 \text{ psia}$$

The pressure loss measured obtained is 825 psia, where the data used is bottom hole pressure and well head pressure obtained from measurement in the well. The difference between bottom hole pressure and well head pressure obtained from each well is the measured pressure loss in the tubing ($\Delta P_{measured}$).

For the error percentage obtained from each method is the difference between P_{wf} calculated and P_{wf} measured compared to the P_{wf} measured. From that calculation, will be obtained error percentage comparison from each method. For example, error percentage on Well Z-01 using Cullender and Smith Method is:

$$\text{Error percentage} = \frac{(P_{wf})_{calculated} - (P_{wf})_{measured}}{(P_{wf})_{measured}} = \frac{(2318 - 2170) \text{ psia}}{2170 \text{ psia}} = 0.0682$$

$$\text{Error percentage} = 6.82\%$$

After calculating error percentage from each well using all methods, then it can be seen the average percent error of each method. While the average error percentage in one method is the sum of the percent errors of all wells in one method divided by the number of the wells. For example, average error percentage on Cullender and Smith Method is:

$$\text{Average error percentage} = \frac{(\text{Error percentage well 1 + well 2 + well ... n})}{\text{number of wells}}$$

$$\text{Average error percentage} = \frac{(6.82 + 0.44 + 6.69 + 4.14 + 4.73 + 0.92 + 3.07)}{7} = 3.83\%$$

Based on the calculation conducted from each method shown in **Table 2**, the Cullender and Smith Method have the lowest average error percentage compared to other methods. In this study, it can be stated that the Cullender and Smith Method is more valid than other methods to determine pressure loss in the tubing.

IV. CONCLUSION

Based on this study, it can be concluded that:

1. The Cullender and Smith method resulting the smallest error percentage in calculating the pressure loss in the tubing with 3.83% compared to the Average Temperature and Deviation Factor Method with 5.38% and the Sukkar and Cornell Method with 5.65%.
2. The Cullender and Smith method is most widely used in the field to determine the pressure loss in the tubing in gas wells, so it can be said to be valid or the most accurate method for used in the field compared to other methods due to resulting the smallest percent error from the calculation.

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