

# Study On Hydrate Formation Potential in Natural Gas Pipeline

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## Abstract

The formation of hydrates within the natural gas pipeline poses a significant challenge that requires careful attention and management. This research endeavor is focused on predicting and forecasting the specific conditions under which hydrate formation is likely to occur within the natural gas pipeline infrastructure. By understanding these conditions, it becomes possible to implement preventive measures and strategies to mitigate the risks associated with hydrate formation. The work aims to ascertain the precise temperatures and pressures at which hydrocarbon and water dew points are reached within gas streams. Determining these dew points is crucial because it allows for the optimization of pipeline operations, ensuring that the gas remains in a stable state and does not precipitate into hydrates or condense into liquid form, which could lead to blockages and operational inefficiencies.

The study examined the formation of hydrates and the deposition of hydrocarbon slugs, which are primary concerns in gas pipelines that can lead to significant environmental damage and substantial financial repercussions. The prediction of hydrate formation conditions and the pipeline segments where these conditions are likely to occur was conducted to provide a basis for designing a cost-effective hydrate prevention strategy. Additionally, the prediction of the hydrocarbon and water dew points of a gas stream was accomplished using two equations of state within the Aspen HYSYS simulation software. This analysis confirms that under specific conditions of elevated pressure and reduced temperature, hydrate formation is promoted or favored, and water condenses out prior to hydrocarbons in natural gas streams. This paper serves as a guide for forecasting the conditions conducive to gas hydrate and hydrocarbon liquid formation, as well as identifying pipeline sections prone to hydrate formation in long-distance pipelines. In essence, this research seeks to enhance the safety, reliability, and efficiency of natural gas transportation by providing a comprehensive understanding of the thermodynamic conditions that govern the behavior of gas streams within pipelines.

## Introduction

Fossil fuels recorded major contributions to global energy consumption with an estimated 87 million barrels/day (BPD) and this has raised the stakes for oil production despite obvious productivity decline (Kerunwa et al. 2024). Fossil Fuels could be solid (coal and/or tar sand), liquid (crude oil) or gaseous (natural gas) in nature (Meyers 2002), but gaseous based fossil fuel has recorded significant global attention from several countries (Ikoku 1992) due to its excellent eco-properties compared to other fossil fuel forms (Mohammad 2009). Natural Gas is a gas derived conventional underground formation either as gas associated with crude oil or free water (Anyadiiegwu et al. 2014), and comprises predominantly of methane, significant quantities of ethane, propane, butane and pentane (Abdel et al. 2003), and other impurities such as water vapour, carbon (iv) oxide and hydrogen sulphide. The study of hydrates (also known as “gas hydrates”) has captured the attention of the industry and the economy because of the identification of its vast deposits (as new energy source), concurrent lack of traditional fossil fuels (Guimin et al. 2022) and its adverse effects in pipelines and process equipment. Gas hydrates are structured crystalline materials with an organized structure in which methane and other guest molecules are enclosed in cages made of water molecules and held in place by hydrogen bonds. Since an empty cage lacks thermodynamic stability, these guest molecules are essential for stabilizing the cages (Naser and Brandstatter 2011). Hydrates form at high pressures and low temperatures, in the presence of free water especially near regions with significant agitation and turbulence like valves

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Improved Oil and Gas Recovery

DOI: 10.14800/IOGR.1355

Received January 2, 2025; revised March 27, 2025; accepted May 27, 2025.

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and bends and can impede pipelines in deep sea or permafrost conditions. Due to this clogging, dangerous working conditions, high operational costs, and even the possibility of fatal accidents are all created. Predicting the critical sections of the natural gas pipeline at which hydrates form is very crucial for pipeline operation optimization and for a better pipeline cost optimized hydrate prevention methods. However, since it is not feasible, to empirically determine segmental variations in pressure, temperature, density, viscosity, etc., along a transmission pipeline, these parameters are determined by applying thermodynamic and conservation principles (Carroll 2003). Also, precise measurement of hydrocarbon dew points is vital in achieving safe and efficient transportation through natural gas pipelines specific for single phase fluids (Shoaib et al. 2018). The conditions (pressure and temperature) at which the heavier elements condense out of the gas stream and turn into liquids are known as the hydrocarbon dew point (HCDP). In some regions, ambient temperatures regularly cause natural gas streams to cool to their hydrocarbon dew points, resulting in condensation taking place in transmission pipelines. If these condensed liquids are not recovered, the stream will lose the heating value they represent, and the liquids themselves could cause equipment in the natural gas delivery system to malfunction, (George et al. 2005). From an analytical gas composition, various techniques can be used to predict hydrocarbon dew point using chilled mirror apparatus, various software programs and equations of state. Industry experience, however, suggested that these various approaches would yield noticeably different outcomes, particularly when the proportions of heavier and hexane (C6)-containing substances are significant (Galatro and Marin-Cordero 2014).

## Methodology

**Hydrate Formation Prediction.** HYSYS simulation package was used to simulate the thermodynamic environment that will suit transportation of the natural gas stream through a gas pipeline. With the Peng Robinson's equation of state (PR EOS) as the fluid package, the temperature and pressure variations at varying sections of the pipeline were determined. For each pipeline section, HYSYS calculates the Hydrate formation temperature at the prevalent section's pressure, for which a careful comparison with the section's prevalent temperature determines the pipeline section's susceptibility to hydrate formation. Hammerschmidt correlation for hydrate formation temperatures used to validate the formation temperatures obtained at each pipe section's pressure.

$$T = 8.9P^{0.285} \text{ ,.....(1)}$$

where T is the hydrate formation temperature, Fahrenheit; and P is the pressure, psi.

**Table 1** displays the detailed composition of the natural gas that is utilized for the purpose of predicting the formation of gas hydrates. The primary constituent found within this natural gas is methane, which plays a crucial role in the overall analysis and understanding of hydrate behavior.

**Table 1—Composition of the natural gas for hydrate prediction.**

	Mole Fraction
Methane	0.7120
Ethane	0.1040
Propane	0.0644
i-Butane	0.0090
n-Butane	0.0196
i-Pentane	0.0051
n-Pentane	0.0056
n-Hexane	0.0024
n-Octane	0.0001
H <sub>2</sub> S	0.0200
Nitrogen	0.0190
CO <sub>2</sub>	0.0380
n-Heptane	0.0008

**Dew Point Prediction.** Two equations of states, namely the Peng-Robinson and the Soave-Redlich-Kwong are used as the fluid packages in HYSYS to predict the hydrocarbon and water dew points of a natural gas stream at designated pressure points and produce a phase envelope for the gas stream. **Table 2** presents the gas composition utilized for the prediction of the dew point. A careful comparison analysis between the hydrocarbon and water dew point with each equation of state confirms the behavior of gas streams, where the heavier components condense out first.

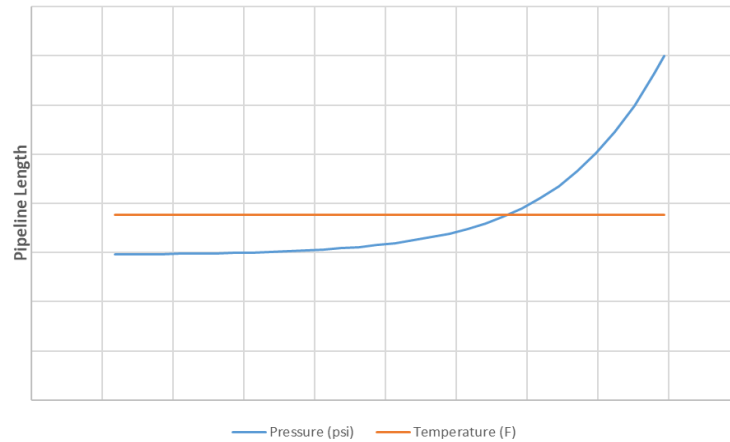
**Table 2—Gas Composition for dew point prediction.**

	Mole Fractions
Nitrogen	0.0569
CO <sub>2</sub>	0.0020
Methane	0.8274
Ethane	0.0790
Propane	0.0214
i-Butane	0.0034
n-Butane	0.0053
i-Pentane	0.0012
n-Pentane	0.0014
n-Hexane	0.0012
n-Heptane	0.0005
n-Octane	0.0001
n-Nonane	0.0000
n-Decane	0.0000
n-C <sub>11</sub>	0.0000
n-C <sub>12</sub>	0.0000
H <sub>2</sub> O	0.0001

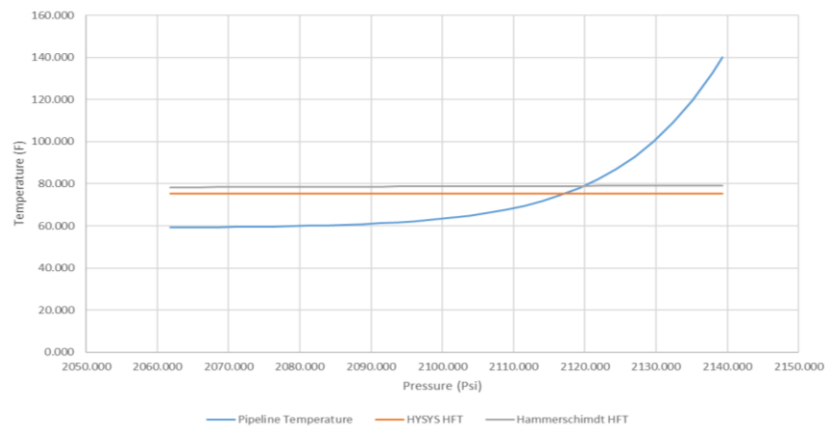
## Results and Discussion

To ascertain which sections of the pipeline are most vulnerable to the formation of hydrates, a meticulous comparison was conducted between the prevailing temperatures of each section of the pipeline and the corresponding temperatures at which hydrates are known to form. This process involved a detailed analysis to identify any potential discrepancies or areas where the pipeline's temperature might drop below the threshold required for hydrate formation. Furthermore, to ensure the accuracy and reliability of the determined hydrate formation temperatures, a validation process was undertaken using the well-established Hammerschmidt correlation. This correlation, which is widely recognized in the industry, provides a means to predict hydrate formation temperatures based on the specific conditions within the pipeline. The results of this validation process, which confirmed the accuracy of the calculated hydrate formation temperatures, are presented and illustrated in **Appendix A1**. This table serves as a crucial reference, offering a comprehensive overview of how the calculated temperatures align with the established Hammerschmidt correlation, thereby providing a robust foundation for further analysis and decision-making regarding the management and mitigation of hydrate formation risks within the pipeline system. It indicates that within section 10 of the pipeline and in areas below, the temperature at which hydrates form exceeds the prevailing temperature of the pipeline, rendering these sections prone to hydrate formation.

**Figure 1** shows that pressure and temperature slowly decline as we move down the pipeline section. It is worthy to note that the pressure decline with increasing pipe length is uniform, while a steep temperature decline is observed at the beginning of the pipeline and a more gradual decline with increasing length of the pipeline. **Figure 2** shows the relationship between the pipeline pressure, pipeline temperature, HYSYS Hydrate formation temperature and the Hammerschmidt Hydrate formation temperature. The region below the pipeline temperature and the HYSYS Hydrate formation temperature depicts the hydrate formation region. An acceptable difference of 4.35% exists between the Hammerschmidt and HYSYS HFT due to the presence of Hydrogen Sulphide in the gas stream, as Hammerschmidt correlation was developed mainly for sweet gases.



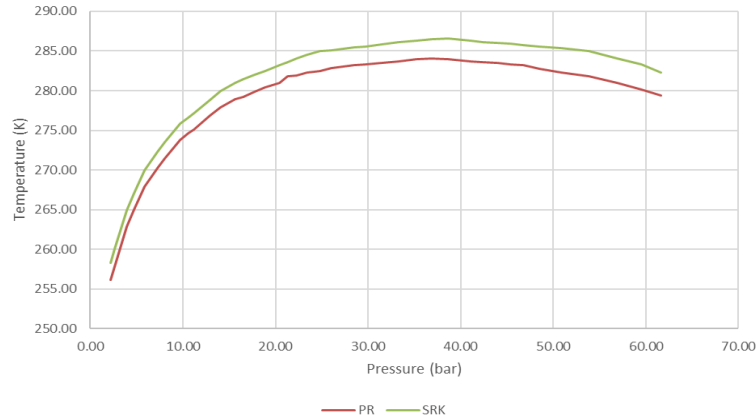
**Figure 1—Pressure and temperature change against pipeline length.**



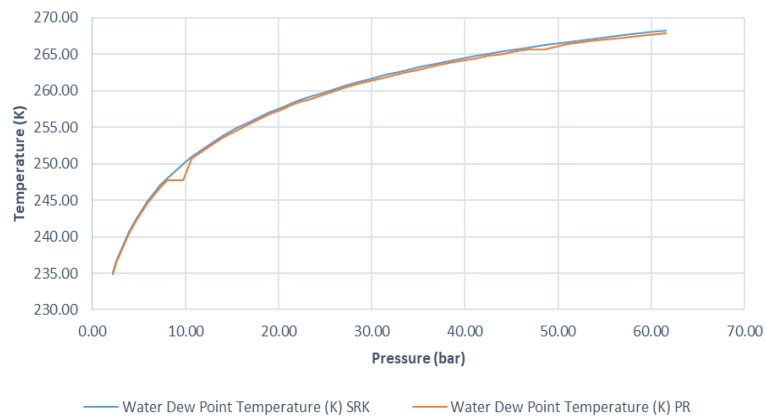
**Figure 2—Pipeline temperature, HYSYS HFT and Hammerschmidt HFT.**

**Appendix A2** presents the outcomes of the simulated water and hydrocarbon dew points employing the Peng-Robinson and Soave-Redlich-Kwong equations of state. A meticulous examination reveals an average disparity of approximately 0.8% and 0.12% for the hydrocarbon and water dew points, respectively, between the dew point temperatures simulated by the Peng-Robinson and those by the Soave-Redlich-Kwong at each specified pressure point. This discrepancy is attributed to the greater complexity of the Peng-Robinson equation of state, which accounts for molecular shape and the presence of associating molecules—those capable of forming weak associations, such as hydrogen bonds—whereas the Soave-Redlich-Kwong equation does not.

Regardless of the type of equilibrium oil saturation (EOS) that is employed in the analysis, a comparison between the water dew points as depicted in **Figure 3** and the hydrocarbon dew point as shown in **Figure 4** reveals a significant observation. Specifically, it becomes evident that the temperature at which the water dew point is reached occurs earlier than the temperature at which the hydrocarbon dew point is attained under certain pressure conditions. This sequence of condensation events can be explained by the inherent properties of the components involved. In this scenario, water, being the heavier component, tends to condense out of the gas stream prior to the hydrocarbon, which is lighter in molecular weight. This behavior is consistent with the general principle that in a gas mixture, the component with a higher molecular weight and a greater affinity for condensation will precipitate out of the gas phase before the lighter components do.

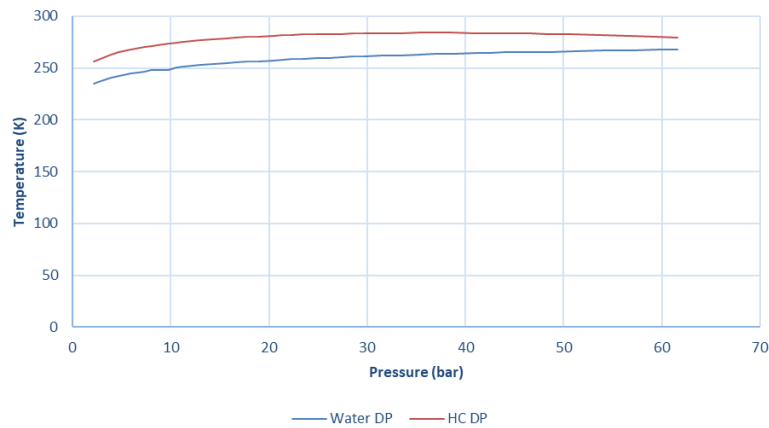


**Figure 3—Comparison between the PR and SRK water dew points.**



**Figure 4—Comparison between the PR and SRK hydrocarbon dew points.**

In **Figure 5**, a detailed comparison has been conducted to illustrate the differences between the hydrocarbon dew point and the water dew point, utilizing the PR EOS as the analytical framework. This comparison reveals a consistent trend where, across a range of different pressures, the hydrocarbon dew point invariably exceeds the water dew point.



**Figure 5—Comparison between hydrocarbon dew point and water dew point using PR EOS.**

## Conclusion

Long-distance pipelines can use the study done on the sample gas pipeline above as a reference for forecasting gas-hydrate formation conditions and anticipated hydrate formation locations. It also provides an insight into designing and cost-optimizing hydrate prevention schemes, like stating the pipeline section to insulate or to inject inhibitors. For this specific pipeline, the remediation methods should be implemented at the beginning sections of the pipeline, as the hydrate formation conditions are most likely to be met at these points. Furthermore, HYSYS can be used to determine the temperature and pressure at which liquid hydrocarbon and water will condense out of the gas stream with reasonable accuracy especially with the Peng-Robinson's and Soave-Redlich-Kwong's equation of state.

## Conflicting Interests

The author(s) declare that they have no conflicting interests.

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## Appendix

**Appendix A1—Pipeline temperature and pressure variations with hydrate formation temperature.**

Pipe Sections	Axial Length (ft)	Pressure (psi)	Temperature (F)	HYSYS HFT (F)	Hammerschmidt HFT (F)
1	0.000	2139.310	140.000	75.419	79.162
2	546.810	2137.900	132.850	75.416	79.147
3	1640.420	2135.120	119.820	75.409	79.118
4	2734.030	2132.390	109.090	75.401	79.089
5	3827.650	2129.700	100.250	75.394	79.061
6	4921.260	2127.050	92.970	75.387	79.033
7	6014.870	2124.420	86.980	75.380	79.005
8	7108.490	2121.810	82.040	75.373	78.977
9	8202.100	2119.220	77.970	75.366	78.950
10	9295.710	2116.640	74.630	75.360	78.922
11	10389.330	2114.070	71.870	75.353	78.895
12	11482.940	2111.520	69.600	75.346	78.868
13	12576.550	2108.960	67.730	75.339	78.841
14	13670.170	2106.420	66.190	75.333	78.813
15	14763.780	2103.870	64.920	75.326	78.786
16	15857.390	2101.330	63.870	75.319	78.759
17	16951.010	2098.790	63.010	75.312	78.732
18	18044.620	2096.250	62.310	75.306	78.705
19	19138.230	2093.710	61.720	75.299	78.678
20	20231.850	2091.170	61.240	75.292	78.650
21	21325.460	2088.630	60.850	75.285	78.623
22	22419.070	2086.090	60.520	75.279	78.596
23	23512.690	2083.550	60.250	75.272	78.569
24	24606.300	2081.000	60.030	75.265	78.541
25	25699.910	2078.450	59.850	75.258	78.514
26	26793.530	2075.900	59.700	75.252	78.486
27	27887.140	2073.350	59.580	75.245	78.459
28	28980.750	2070.790	59.470	75.238	78.431
29	30074.370	2068.230	59.390	75.231	78.404
30	31167.980	2065.670	59.320	75.223	78.376
31	32261.590	2063.110	59.260	75.218	78.348
32	32808.400	2061.820	59.240	75.214	78.334

## Appendix A2—Hydrocarbon and water dew point temperatures using the PR and SRK EOS.

Pressure (bar)	WDP (K)-SRK	WDP (K)-PR	HCDP (K)-SRK	HCDP (K)-PR
2.20	235.14	234.85	258.30	256.13
2.60	236.74	236.46	260.07	257.86
3.90	240.71	240.44	264.94	262.83
4.70	242.58	242.31	267.10	265.05
5.90	244.88	244.61	269.95	267.89
7.30	247.06	246.80	272.30	270.24
8.00	248.00	247.74	273.48	271.42
9.70	250.00	247.75	275.84	273.78
10.60	250.93	250.67	276.58	274.64
11.20	251.50	251.25	277.17	275.10
12.90	252.98	252.73	278.79	276.87
14.10	253.91	253.66	279.97	277.90
15.60	254.97	254.71	281.00	278.90
16.50	255.55	255.30	281.43	279.23
17.70	256.28	256.03	282.03	279.82
18.90	256.97	256.71	282.47	280.40
20.40	257.76	257.51	283.21	281.00
21.30	258.21	257.95	283.60	281.86
22.30	258.68	258.43	284.09	281.88
23.40	259.18	258.92	284.53	282.30
24.80	259.77	259.52	284.98	282.52
26.00	260.25	260.00	285.12	282.85
27.20	260.71	260.45	285.27	283.00
28.50	261.18	260.92	285.42	283.20
29.70	261.60	261.33	285.57	283.35
31.40	262.15	261.89	285.86	283.50
33.30	262.73	262.46	286.10	283.65
35.20	263.27	263.00	286.30	284.00
36.80	263.70	263.43	286.45	284.02
38.70	264.18	263.91	286.60	283.94
41.10	264.74	264.47	286.30	283.70
42.40	265.03	264.76	286.15	283.60
44.00	265.37	265.10	286.00	283.50
45.40	265.66	265.38	285.90	283.35
46.80	265.93	265.65	285.71	283.21
48.50	266.25	265.70	285.57	282.76
50.90	266.67	266.39	285.36	282.32
53.90	267.15	266.87	284.98	281.80
56.90	267.60	267.31	284.09	281.00
59.50	267.96	267.67	283.35	280.11
61.60	268.23	267.94	282.32	279.37