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A Systematic Approach in Determining Hydrate Formation in Natural Gas and Gas-to-Liquid Process Plants

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Abstract- Natural gas processing plants are not immune to hydrate formation and gas plant operators are constantly on the watch for potential hydrate formation point in the process plant. In some process plant, automatic device have been design and installed to control process variables (temperature and pressure), while in others, control of process variables are done manually by switching on heaters to raise the temperature of a potential hydrate formation stream. The later can cause operation difficulty, but can be avoided during Front End Engineering Design (FEED) stage. This paper, design a systematic approach to determine hydrate formation during the design stage of the process plant. Three stages are implemented in the approach. Stages 1 and 2 are design and simulation of Natural Gas and Gas-to-Liquid (GTL) Process Flow Diagrams (PFDs) using HYSYS. Stage 3 is the utilization of two packages in the software to achieve two levels of calculations. First, the optimizer package was used to determine the optimum operating temperature of a stream that will minimize the amount of water content contained in the stream. Secondly, the hydrate formation utility package was then used to determine the temperature at which this water starts to condense out from the stream. Results obtained show that for Gas Sweetening (GS) Feed, optimum operating temperature is 32.9^oC and the water content is 0.129 bbl/MMScf (723.25 Kg/MMScm). The hydrate formation temperature of this stream is 24.71^oC. When the temperature was drop to 23^oC, $2.9x10^5$ KJ/h amount of heat was loss from the stream, which resulted in (1) liquid condensing from the stream, (2) hydrate formation, (3) upset of column operating conditions, and (4) heat exchanger failure. Hydrogen to Carbon monoxide ratio was 1.75:1 at the steam reformer reactor and 5.88:1 at the water gas shift reactor. Deployment of this method at the FEED stage, can minimize shutdown time due to liquid deposit, reduce operating cost and guaranty high quality of product during operation of the plant.

Keywords- *Gas sweetening, Dehydration, Clathrates, Gas hydrate, Wwater content, Optimum Condition*

I. INTRODUCTION

Natural gas produced from under saturated or saturated reservoir is called Associated Gas (AG), whereas those produced from gas reservoir is called Non-Associated Gas (NAG). The components of both AG and NAG are Methane(C_1), Ethane(C_2), Propane(C_3), i-Butane(i-C_4), n-Butane(n-C_4), i-Pentane(i-C_5), n-Pentane(n-C_5), heavier hydrocarbon and non-hydrocarbon components such as Acid gases (CO_2 and H_2S), Water vapour and Nitrogen. The composition of each component varies from reservoir to reservoir depending on the geological formation and region. The presence of non-hydrocarbon components and water vapour in the natural gas, poses a threat in its utilization. Hence, processing of the gas is important for it to meet its purpose. The processing of the natural gas involves compression, which knocked off heavier hydrocarbon liquids, removal of acid gases (gas sweetening), water vapour (dehydration), and other non-hydrocarbon components, which may affect the performance of the gas during utilization. These processes are highly prone to hydrate formation, if the operating conditions (temperature, pressure, and compositions of heavier hydrocarbons) are not properly controlled. Processed natural gas can be converted through catalytic chemical reactions into liquid products such as LPG, Gasoline, Naphtha, Middle Distillate and Lube base wax. This conversion process is called Gas-To-Liquid (GTL) and one of the best known technology which is been use in the conversion process is the Fischer-Tropsch process.

In the GTL process, synthesis gas or syngas (CO and H_2) is generated by the reaction of natural gas (containing high percentage of methane) with steam in a steam reformer reactor. The important parameter in the GTL process is H_2 to CO ratio.

This paper present a systematic approach in determining hydrate formation in natural gas and GTL processes. The objective is to design and simulate a steady state process of natural gas treatment and GTL processes, to determine water content of selected streams, and to determine the optimum process minimum temperature (below which the water starts to condense to form hydrate) of selected streams.

II. NATURAL GAS HYDRATES

Natural gas hydrates or clathrates are non-stoichiometric solids, comprises of hydrocarbon gas (guest) trapped within the cavities of a rigid “cage like” lattice of hydrogen bonding water molecules (host). These compounds contains clusters of gas-trapping polyhedral formed by pentagonally and hexagonally arranged hydrogen-bonded water molecules of which Van der Waal forces stabilized and support the individual polyhedral forming the hydrate lattice and restrict the translational motion of the guest molecules (Bufett, 2000). Both host and guest must be present for the solid to form, but the guest will occupy not all the cavities.

III. HYDRATE STRUCTURES IN NATURAL GAS SYSTEM

Hydrate structure are classified into three recognize crystalline structures based on the geometries of their constituent water cages. In all, water (host) molecules build the lattices and the hydrocarbons, CO_2, H_2S, and nitrogen (guest) occupy the cavities. These structures are structure I, II and hexagonal structure H. Each crystalline structure contains geometrically distinct water cages with different size cavities, which typically accommodate only one guest molecule ranging in diameter from 0.4-0.9nm (Sloan, 2003). Smaller molecules such as C_1, C_2, N_2, CO_2, and H_2S forms a body centered cubic structure called structure I. Larger molecules such as C_3, i-C_4, and n-C_4 form a diamond lattice structure called structure II. Normal paraffins molecules larger than n-C_4 do not form structure I and II hydrates, as they are too large to stabilize the lattice. However, structure H hydrates are form by isoparaffins and cyclohexanes larger than pentane.

IV. WATER CONTENT OF NATURAL GAS SYSTEM

Two calculations are primary to water hydrocarbon system: calculation of the water content of the gas and prediction of the conditions below which the water will condense to form hydrate.

The water content of a natural gas is dependent on temperature, pressure, and composition of the natural gas system. The effect of composition increases with pressure and is particularly important if the gas contains CO_2 and/or H_2S. In 1958, McKetta J. J and A. H Wehe, published generalize temperature-pressure correlation base on experimental data available at that time. The correlation was used to estimate the water content of sweet natural gas containing over 70% methane and small amount of hydrocarbons. Both CO_2 and H_2S at high concentration contain more water at saturation than methane (C_1) or sweet natural gas mixtures. The relative amount varies considerably with temperature and pressure.

Compbell J. M in 1984 developed an equation use to estimate the water content of sour natural gas system containing up to 40% H_2S and 50% CO_2. The equation is given as:

$$W = y_{Hc}W_{HC} + y_{CO2}W_{CO2} + y_{H2S}W_{H2S} \tag{1}$$

Where W= water content of natural gas, $y_{Hc} = 1 - y_{CO2} - y_{H2S}$, W_{HC} =water content of hydrocarbon gas at T, P, y_{CO2} = mole fraction of CO_2, y_{H2S} = mole fraction of H_2S, W_{CO2} = water content of pure CO_2 at T, P, and W_{H2S} = water content of pure H_2S at T, P. W_{H2S}, W_{CO2}, and W_{HC} are read from Campbell's correlation charts for water content of sweet natural gases.

Another method use to estimate the saturation water content of natural gas is given as

$$W = f(T, P, y) \tag{2}$$

Where $y = y_{H2S} + 0.75y_{CO2}$ (3)

With natural gas containing CO_2, the concentration of CO_2 must be converted to an equivalent H_2S concentration. For this method, it is assume that the CO_2 will contribute as much water to the gas mixture, on a molar basis, as H_2S. W is read from Campbell's correlation charts for water of sweet natural gases.

V. PREDICTION OF HYDRATE FORMATION

One major requirement for hydrates formation in a natural gas system is that some water molecules must be present in either the vapour or condensed hydrocarbon phase with hydrate forming components. Once favorable pressure and temperature conditions are reached (high pressures or low temperatures), the mixtures of hydrate-forming molecules and water molecules, form a non-stoichiometric solid phase. Several methods exist for determining the pressure and temperature at which hydrate begins to form: analytical, graphical and experimental methods.

The Engineering Data Book, (2004) provides a hydrate prediction curve for natural gas, as a function of gas specific gravity. From the curve a model equation was developed to show a functional relationship (as an approximation) between temperature, pressure and specific gravity of the gas. For below 1,000psi, the curve can be approximated by

$$t(°\mathrm{F}) = -16.5 - \frac{6.83}{\gamma_g^2} + 13.8 \ln P(psia) \tag{3}$$

$$t(°\mathrm{C}) = -6.44 - \frac{3.79}{\gamma_g^2} + 7.86 \ln P(bar) \tag{4}$$

Where, γ_g is the specific gravity of the gas.

The above equation shows that knowledge of the natural gas compositions are required to calculate the gas specific gravity and with the formation pressure, the hydrate formation temperature can be determine.

Makogon, (1981), presented a mathematical relationship between temperature and pressure, which can be used to predict hydrate formation. The relationship is define as

$$\ln P = a(T + kT^2) + b \tag{5}$$

Where P = Pressure in atm, T = Temperature in K, a, b, and k are coefficients which depends on the component and specific gravity of the gas mixture. For example CH_4 at temperature range of 0 to 23^0C, a = 0.417, b = 1.415, and k = 0.011.

Katz et al, (1959), proposed a graphical method for predicting hydrate formation. Like the prediction curve in the Engineering Data Book 2004, it requires knowledge of the gas composition and vapour-solid equilibrium constant called the K-values. The equation is define as

$$x_i = \frac{y_i}{K_i} \tag{6}$$

Where x_i is the mole fraction of component i in the solid phase on a water-free basis, y_i is the mole fraction of component i in the gas phase on a water-free basis, K_i is the vapour-solid equilibrium constant for component i, and it is temperature and pressure dependent. This method is iterative; a temperature is assumed and the K-values for each component in the gas mixture corresponding to the temperature are determined from Katz Charts. Thereafter, the values of x_i are calculated from the equation. If the assumed temperature is the hydrate formation temperature then,

$$\sum_{i=1}^{n}(x_i) = \sum_{i=1}^{n}\left(\frac{y_i}{K_i}\right) = 1 \qquad (7)$$

Otherwise, another temperature is assumed and the process is repeated.

VI. STEAM REFORMING

Natural gas and steam are catalytically and endothermically converted to syngas at temperature range of 850 to 940^{0}C.

$$CH_4 + H_2O \xrightarrow{catalyst} CO + 3H_2$$

The interest is on the H_2 and CO ratio. This is achieved through water shift reaction. For steam reforming H_2 to CO is greater than 3:1. For partial oxidation, the ratio is less than 2:1, and for auto-thermal reforming the ratio is 2:1 (AL-Shalchi, 2006).

VII. MATERIALS AND METHODS

A. *Stage 1: Gas Treatment Process*

A gas flow rate of 10MMScfd at 82^{o}F and 1300psia was used in the simulation of the gas treatment process. Table 1 shows the properties of the natural gas.

TABLE I. PROPERTIES AND PARAMETERS

Temperature = 82^{o}F (28^{o}C), Pressure = 1300Psia (8961Kpa), Gas flow rate G= 10MMScfd	
Properties of the Natural Gas	
Average weight (lbmas/lbmol	23.055
Specific Gravity	0.796
z-factor	0.707
Density (lbm/cuft)	7.29
Formation Volume Factor (cuft/SCF)	0.008342
Viscosity (cp)	0.01512

1) *Mass flow Rate of Gas*

$$\dot{m} = (B_g)(\rho)(G) = 0.008342\,\frac{cuft}{Scf}\cdot 7.29\,\frac{lbm}{cuft}\cdot 10x10^6\,\frac{Scf}{day} = 608132\,\frac{lbm}{day} = 608132\,\frac{lbm}{day}\cdot 0.454\,\frac{Kg}{lbm}\cdot\frac{day}{24hr} = 11504\,\frac{Kg}{hr}$$

2) *Process Simulation and Description*

The natural gas treatment process consists of the following major units:

- Inlet separator
- Gas Sweetening Contactor
- MethylEthyleneAmine Recycling Unit
- Gas Dehydration Contactor
- TriEthyleneGlycol Recycling Unit

The feed parameters; Composition, temperature, pressure, and mass flow rate were entered into the software. The inlet separator receives the feed stream and flashes it at separator's pressure and temperature of 8861KPa and 27.65^{o}C. The compressor raises the pressure of the gas to 9350Kpa, before entering into heat exchanger 1. This is to enable proper heating of the rich MEA as it goes to the recycle unit. The exit stream from the tube side of Hx-1 enters the gas sweetening column at temperature and pressure of 32^{o}C and 9340KPa. Lean MEA enters into the column at temperature of 20^{o}C, less than the GS feed temperature of 32^{o}C. This is to enable absorption of the acid gases by the MEA. The top product is cooled to 25^{o}C before entering into the dehydration unit. Lean TEG is feed into the unit at temperature of 19^{o}C, below the feed temperature of 25^{o}C.

A careful observation of Figure 1 shows that there are 36 material streams and 12 energy streams, but in this work, only 12 material streams were selected to show the changes in composition as the process variables (Temperature and Pressure) changes. Table A1 and Table A2 of Appendix A, shows the composition (in mole fraction) and the process variables of the 12 material streams.

B. *Stage 2: Syngas Production Process*

The processed natural gas from stage 1 is converted to syngas, via Steam Reformer Reactor. The H_2 to CO ratio is very low (less than 1.5:1) at the exit of the reactor. To increase the ratio, a water Gas Reactor was use. In the reactor, steam was use to react with the syngas to increase the hydrogen content and convert CO to CO_2. For environmental concern, this conversion is a good one.

The fifth column (GTL feed gas) of Tables A1 and A2 shows the components composition and process variables of the natural gas of the first stage. These parameters are use as input to the second stage. This stage involves chemical reactions, thus a chemical equation was modeled for each reactor.

Steam Reformer Chemical Reaction (Conversion Reactor)

CH_4

$$C_2H_5 + 2H_2O \longrightarrow 4CO + 6.5H_2$$

CO_2

$\Delta H = 5.9x10^5$ KJ / Kgmol at 25^{o}C

Water Gas Shift Chemical Reaction (Equilibrium Reactor)

$$CO + H_2O \longrightarrow H_2 + CO_2$$

$\Delta H = -4.2x10^4$ KJ/Kgmol at 25^{o}C

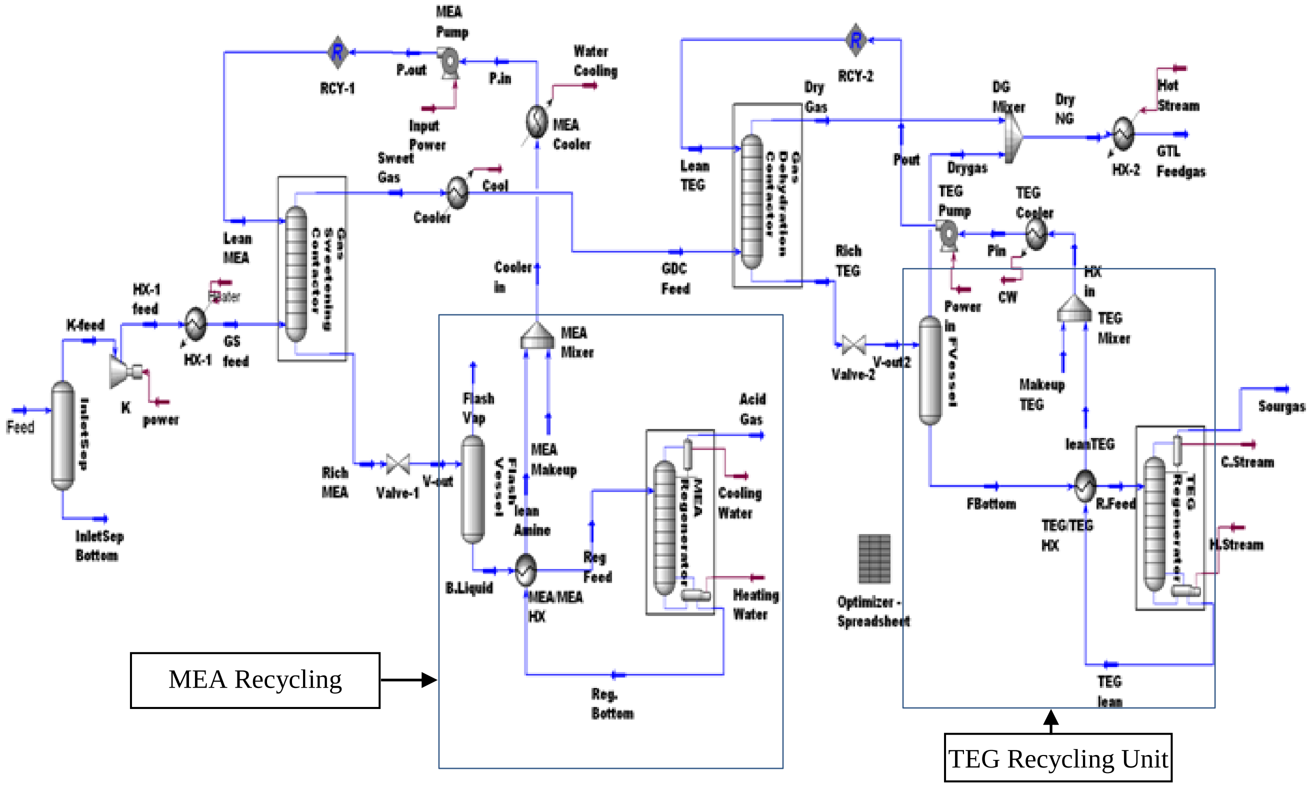

Figure 1. Process Flow Diagram of Stage 1

1) *Process Simulation and Description*

The steam reformer was modeled as a conversion reactor and the water gas shift reactor was modeled as an equilibrium reactor. The steam is available at 1500KPa and 198.33°C and is a dry saturated steam. The natural gas and the steam are mixed and the mixture enters the steam reformer at a temperature of 700°C. To avoid carbon deposit in the reformer, the flow rate of the steam is set relative to NG flow rate, such that enough steam is available to suppress carbon formation.

The reformer top product at temperature of 800°C, exchange heat with the mixer's mixture before it enters the water gas shift reactor at a temperature of 450°C. The HX-4 feed at temperature of 400°C is cooled, before it enters the splitter at temperature of 40°C. The most important stream in the flow sheet, is the H_2:CO ratio. This ratio is 1.75**:**1 for the steam reformer, at 80% conversion of methane. However, the water gas shift reaction is expected to increase the ratio, which is 5.87**:**1 at 60% conversion of CO. The CO_2 is removed from the Abs feed in the component splitter, which is modeled as an absorber, to produce the syngas. The syngas at temperature of 40°C is heated to 260°C and 1400KPa to dry it, prior to conversion to liquid hydrocarbon via F-T reactor.

Again, a careful observation of Figure 2 shows that there are 13 material streams and 6 energy streams, but only 5 material streams were selected to show changes in composition as the process variables changes. Table A3 and Table A4 show the composition and process variables of the material streams of the 5 material streams.

Hydrogen to Carbon monoxide Ratio;

- Steam Reformer Reactor: Reformer Top H_2:CO = 1.75 : 1
- Water Gas Shift Reactor: HX-4 feed H_2:CO = 5.88 : 1

C. *Stage 3: Optimization*

Optimizer package in HYSYS software was use to carry out the optimization. Primary variables of interest (temperature) of a particular stream were imported from the flow sheet and a search for an optimum temperature was carried out. The optimum value will minimize the objective function. With the searched temperature, stream pressure, and minimum y, the water content W can be calculated.

Mathematically;

$$W = f(T, P, y) \tag{8}$$

Where

$$y = y_1 + 0.75y_2 \tag{9}$$

The objective and the constraint function are;

Objective function

$$min\ y = y_1 + 0.75y_2 \tag{10}$$

Subject to (Constraint function)

$$y_1 \leq 0.03 \tag{11}$$

$$y_2 \leq 0.04 \tag{12}$$

Non-negative conditions

$$y_i \geq 0 \qquad (13)$$

Where $i = 1{,}2,$

Where y_1 *and* y_2 are the mole fraction of H_2S and CO_2 of a particular stream, y is the pseudocomposition of H_2S and W is the water content of the gas for the same stream at the search temperature and stream pressure. It is assumed that the CO_2 will contribute as much water to the gas mixture, on a molar basis, as H_2S (GPSA Section 20, 1998). W was read from Campbell's chart (Campbell, 1984).

The hydrate formation utility package, was then utilize to determine the temperature at which the water content starts to condense to form hydrate.

The following streams were optimized, to determine the minimum amount of water content each stream contains at the optimum temperature (GS feed, GDC feed, Reg. feed, and NG (GTL feed gas)).

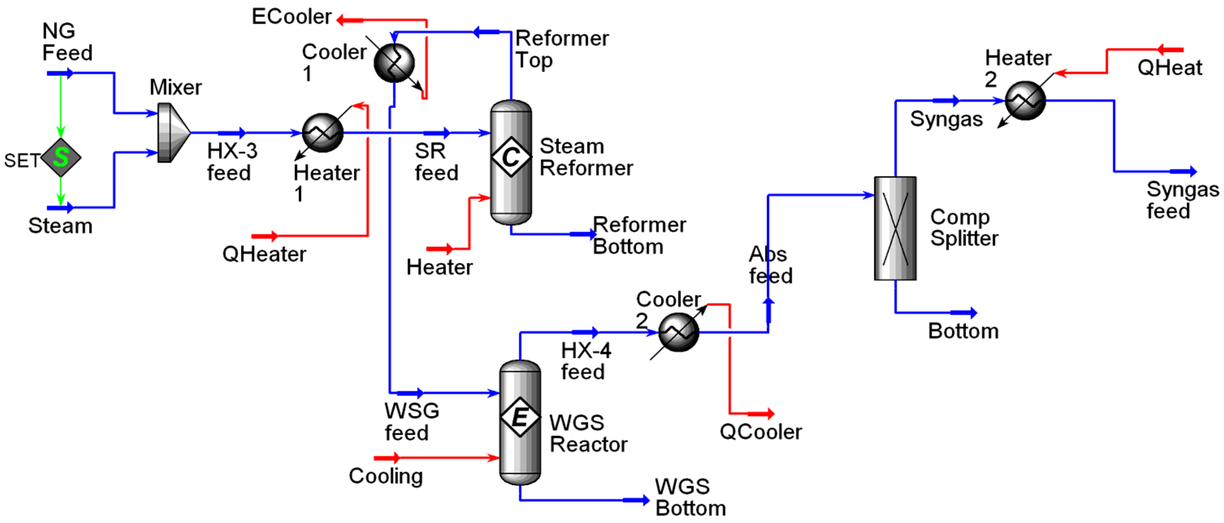

Figure 2. Process Flow Diagram of Stage 2.

D. *Optimum Operating Values*

1) *Stage 1: Gas Treatment Process*

GS feed

Minimum value $y = 0.0806\ (8.06\%)$

Optimum temperature $T = 32.9^oC\ (91.22^OF)$

Stream pressure $P = 9341KPa\ (1355Psia)$

Minimum water content

$W = f(91.22^oF, 1355Psia, 8.06)$

$= 0.129\,\frac{\text{bbl}}{\text{MMScF}} = 723.25\,\frac{\text{Kg}}{\text{MMScm}}$

GDC feed

Minimum value $y = 0.069\ (6.9\%)$

Optimum temperature $T = 25.75^oC\ (78.35^oF)$

Stream pressure $P = 9290KPa\ (1347.77Psia)$

Minimum water content

$W = f(78.35^oF, 1347.77Psia, 6.9\%)$

$= 0.07\,\frac{\text{bbl}}{\text{MMScF}} = 392.46\,\frac{\text{Kg}}{\text{MMScm}}$

Reg. feed

Minimum value $y = 0.02902\ (2.902\%)$

Optimum temperature $T = 34.993^oC\ (94.987^oF)$

Stream pressure $P = 9390KPa\ (1362Psia)$

Minimum water content

$W = f(94.987^oF, 1362Psia, 2.902\%)$

$= 0.10\,\frac{\text{bbl}}{\text{MMScF}} = 561.15\,\frac{\text{Kg}}{\text{MMScm}}$

GTL Feedgas

Minimum value $y = 3.25x10^{-9}\ (3.25x10^{-7}\%)$

Optimum Temperature $T = 15.00^oC\ (59.00^oF)$

Stream pressure $P = 9100\ KPa\ (1320\ psia)$

Minimum water content

$W = f(59.00^oF, 1320\ psia, 3.25x10^{-7}\%)$

$= 0.032\,\frac{\text{bbl}}{\text{MMScF}} = 179.57\,\frac{\text{Kg}}{\text{MMScm}}$

E. *Hydrate Formation Condition*

1) *Hydrate calculation model: Vapour Only*

GS feed

Optimum temperature $T = 32.9^0C\ (91.22^OF)$

Hydrate formation temp $T_f = 24.71^oC\ (76.48^OF)$

Stream pressure $P = 9340KPa\ (1355\ psia)$

Stream temperature $T = 32^oC\ (89.6^OF)$

Type I & II hydrate will form at this temperature.

GDC feed

Optimum temperature $T = 25.75^oC\ (78.35^OF)$

Hydrate formation temperature $T_f = 14.86^OC(58.75^OF)$,

Stream pressure $P = 9290\ KPa\ (1347\ psia)$

Stream temperature $T = 25^0C\ (77.00^OF)$

Type I & II hydrate will form at this temperature.

Reg. feed

Optimum temperature $T = 34.993^oC\ (94.99^OF)$

Hydrate formation temp $T_f = 16.49^oC\ (61.68^OF)$,

Stream pressure $P = 9390KPa\ (1362\ psia)$

Stream temperature $T = 35^0C\ (95.00^OF)$

Type I & II hydrate will form at this temperature.

GTL Feedgas

Optimum temperature $T = 15.00^oC\ (59.00^OF)$

Hydrate formation temp $T_f = 14.73^o$C, *(58.51^{O}F)*

Stream pressure $P = 9100\ KPa\ (1320\ psia)$

Stream temperature $T = 15.00^oC\ (59.00^OF)$

Type I & II hydrate will form at this temperature.

F. *Stage 2: Syngas Production Process*

1) *Optimum and Hydrate Formation Condition*

SR feed

Stream temperature $T = 700^oC$

Stream pressure $P = 1481KPa$

Water content $W = 912.5\frac{Kgmol}{hr}$

Hydrate formation pressure $P_f = 259960KPa$,

Type I hydrate will form at this pressure.

Abs feed

Stream temperature $T = 40^oC$

Stream pressure $P = 1266KPa$

Water content $W = 912.2\frac{Kgmol}{hr}$

Hydrate formation temperature $T_f = -20.2^oC$,

Type I hydrate will form at this temperature.

WGS feed

Stream temperature $T = 500^oC$

Stream pressure $P = 1376KPa$

Water content $W = 912.4\frac{Kgmol}{hr}$

Hydrate formation pressure $P_f = 259960KPa$,

Type I hydrate will form at this pressure.

Syngas feed

Stream temperature $T = 260^oC$

Stream pressure $P = 1052\ KPa$

Water content $W = 0.00\frac{Kgmol}{hr}$

Hydrate formation temperature $T_f = -26.3^oC$,.

Type I hydrate will form at this temperature.

VIII. ANALYSIS OF RESULTS

The two important results obtained in the simulation process are:

1. The minimum amount of water content, contained in a stream at the optimum temperature.
2. The temperature or pressure at which this water will start to condense out from the system to form hydrate.

The optimum and hydrate formation results obtained are representative of the simulations of stages 1 and 2 process flow sheets. The analysis of the PFDs will base on the parameters of material streams in stages 1 and 2, the simulated results of stage 3 and the phase envelope in Fig. B1 to Fig. B7 in appendix B. However, a close look at the stream's optimum, and hydrate formation conditions, reveal that the streams and units in the PFDs in stages 1 and 2 are in operable conditions, since their temperatures are well above the hydrate formation temperatures at the stream pressures. This is clearly visible in Fig. B1 to Fig. B7. The turquoise color line represents the hydrate line and it separates two regions: the region to the left of the line signifies hydrate formation region and the region to the right signifies the region of safer operation. Decrease in temperature to the left of the hydrate line, will cause water to condense out of the streams, at this point hydrate formation is imminent. Therefore, to avoid the system been plug with hydrate, the plants should be operated at temperatures to the left of the hydrate lines. These temperatures are well above the dew point temperature of the streams and it is safer to operate the plant if temperatures are selected from this region. However, selection of a particular temperature will depends on the judgment of the design engineers.

A test was done on the simulation to reduce the temperature of the streams GS feed, Reg. feed, and GDC feed from 32°C, 34.99°C, and 25.75°C to 23°C, 15°C, and 13°C, below their dew point temperature. Table 2 shows the effect of this reduction.

TABLE II. CHANGES IN HEAT FLOW

Streams	**Heat Flow (KJ/h)**		
	Before	**After**	**Changes**
GS feeed	$-4.76x10^7$	$-4.79x10^7$	$-2.90x10^5$
Reg feed	$-3.19x10^8$	$-3.23x10^8$	$-4.20x10^6$
GDC feed	$-1.61x10^7$	$-1.62x10^7$	$-1.00x10^5$

The GS feed losses heat at the rate of $2.9x10^5$ KJ/h at 23°C. The attendant effect causes liquid to condense from the stream and thus carry more liquid content into the Gas Sweetening Column. At this state, hydrate formation is imminent the stream pressure drop below the column stage pressure, causing the column to operate at low efficiency. Similar changes in heat flows were observed in other streams.

Similar effect occurred when the syngas feed is reduced to -27°C, below the hydrate formation temperature.

IX. CONCLUSIONS

Natural gas processing plant is highly prone to hydrate formation if the temperature and pressure of the streams are not properly controlled, and if the process facilities are not check regularly for potential failure. The cost of handling the above problem is very high. It is therefore important that in the start-up of the design of a process plant, the method applied from the conception stage to the commissioning stage should be economical, save engineering time, reduce operating cost, increase operation performance, increase returns on investment, increase product (hydrocarbon liquids and gas) quality, reduce shutdown time and guaranty safe operation of the plant. Therefore, it is important that process design engineers should select temperatures above the hydrate line, when designing natural gas and GTL processing plant. In this paper, the systematic approach will aid design engineers to take technical decision and to solve problems that may arise in the plant during operation, at the start of the design.

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APPENDIX A: STREAMS' PROCESS VARIABLES AND COMPOSITIONS

TABLE A1: COMPOSITIONS OF STREAMS IN MOLE FRACTION

	Streams											
Comp.	**Feed**	**K-Feed**	**Sweet Gas**	**GDC Feed**	**GTL feedgas**	**GS Feed**	**Rich MEA**	**MEA lean**	**Acid Gas**	**Rich TEG**	**TEG lean**	**Sour Gas**
C1	0.7386	0.7431	0.9937	0.9937	0.9998	0.7431	0.1142	0.000002	0.55301	0.0263	0.000005	0.991679
C2	0.064	0.0638	0	0	0.0001	0.0638	0.0229	0.000003	0.111876	0	0	0.000045
C3	0.0512	0.0503	0	0	0	0.0503	0.0181	0.000010	0.086339	0	0	0.000010
i-C4	0.015	0.0145	0	0	0	0.0145	0.0052	0.000007	0.025433	0	0	0.000005
n-C4	0.019	0.0182	0	0	0	0.0182	0.0065	0.000015	0.031915	0	0	0.000007
C5+	0.0154	0.0135	0	0	0	0.0135	0.0049	0.000105	0.023657	0	0	0.000017
N2	0.003	0.003	0.0062	0.0062	0	0.003	0.0001	0.00000	0.000657	0.0002	0	0.008174
CO2	0.052	0.0521	0	0	0.0001	0.0521	0.0187	0.000002	0.091454	0	0	0.000003
H2S	0.0418	0.0416	0	0	0	0.0416	0.015	0.000008	0.073004	0	0	0.000004
TEG	0	0	0	0	0	0	0	0.000000	0.000000	0.9734	0.999873	0.000002
MEA	0	0	0.0001	0.0001	0	0	0.7942	0.999848	0.000653	0.0001	0.000122	0.000055

TABLE A2: PROCESS VARIABLES OF MATERIAL STREAMS

	Streams											
Variables	**Feed**	**K-Feed**	**Sweet Gas**	**GDC Feed**	**GTL feedgas**	**GS Feed**	**Rich MEA**	**MEA lean**	**Acid Gas**	**Rich TEG**	**TEG lean**	**Sour Gas**
Vapour Fraction	0.9902	1.000	1.000	1.000	1.000	1.000	0.000	0.000	1.000	0.000	0.000	1.000
Temp. (^{O}C)	28.00	27.65	15.87	25.00	15.00	32.00	21.37	168.9	28.00	12.79	292.8	19.99
Pres. (Kpa)	8961	8861	9300	9290	9100	9340	9500	113	103	9300	113	103
Molar Flow(Kmol/h)	499	493	211.1	211.1	53.24	493	1371	1089	280.5	5993	5884	159.2
Mass Flow (Kg/h)	11500	11260	3402	3402	854.1	11260	74370	66500	7841	878600	88350	2570
Liquid Vol. Flow(m^3/h	29.68	29.21	11.29	11.29	2.853	29.21	83.34	65.4	17.85	784.8	783	8.505
Heat Flow (KJ/h)	-4.84E7	-4.77E7	-1.62E7	-1.61E7	-4.10E6	-4.76E7	-3.22E8	-2.59E8	-3.05E7	-4.72E9	-4.04E9	-1.19E7

TABLE A3: COMPOSITIONAL OF STREAMS

Comp	**Streams**				
	NG feed	**SR feed**	**WGS feed**	**Abs feed**	**Syngas feed**
C_1	0.9998	0.2723	0.2722	0.2722	0.000
C_2	0.0001	0.000	0.000	0.000	0.000
CO	0.000	0.000	0.0001	0.000	0.1455
CO_2	0.0001	0.000	0.0000	0.0001	0.000
H_2O	0.000	0.7277	0.7275	0.7274	0.000
H_2	0.000	0.000	0.0002	0.0003	0.8545

TABLE A4: MATERIAL STREAMS

Name	Stream				
	NG feed	SR feed	WGS feed	Abs feed	Syngas feed
Vapour fraction	1.000	1.000	1.000	0.2742	1.000
Temp (^{o}C)	15.00	700	500	40	260
Pressure (Kpa)	9100	1481	1376	1266	1052
Molar flow (Kgmol/h)	341.5	1254	1254	1254	0.3756
Mass flow (Kg/h)	5480	21920	21920	21920	2.178
Liquid vol (m^3/h)	18.3	34.77	34.78	34.78	0.001118
Heat flow (Kj/h)	$-2.631x10^7$	$-2.104x10^8$	$-2.223x10^8$	$-2.847x10^8$	-3496

TABLE A5: REACTION BALANCE

Comp	Reformer Reaction			Water Gas Shift Reaction		
	Total inflow	Total Reaction	Total Outflow	Total inflow	Total Reaction	Total Outflow
C_1	341.4	-0.003415	341.4	341.4	0.000	341.4
C_2	0.03415	-0.003415	0.0000	0.0000	0.000	0.000
CO	0.000	0.1366	0.1366	0.1366	-0.08196	0.05465
CO_2	0.03415	-0.003415	0.0000	0.0000	-0.08196	0.08196
H_2O	912.6	-0.06831	912.5	912.5	-0.08196	912.4
H_2	0.000	0.2390	0.2390	0.2390	-0.08196	0.3210

APPENDIX B: PHASE ENVELOPE OF SELECTED STREAMS

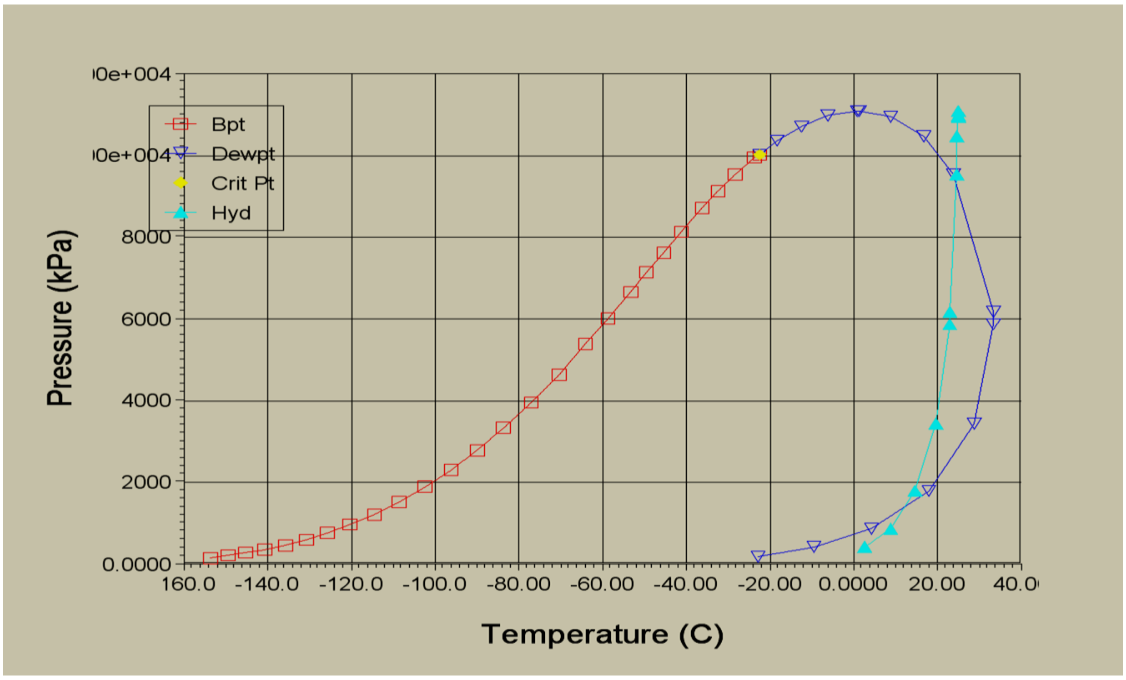

Figure B1: Hydrate Curve for GS feed

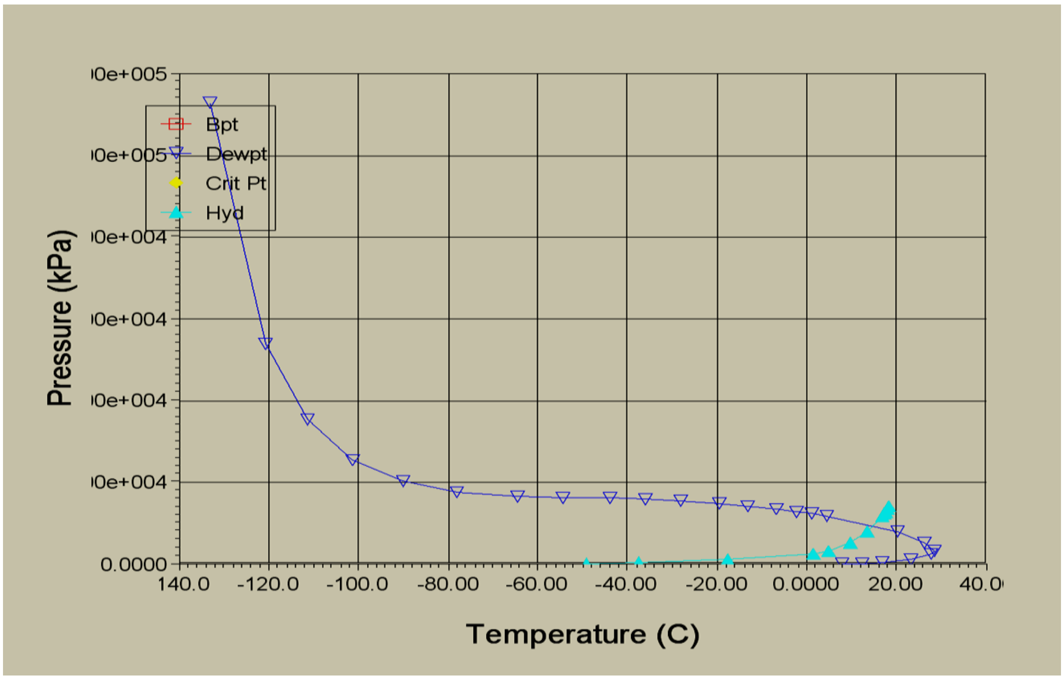

Figure B2: Hydrate Curve for GDC feed

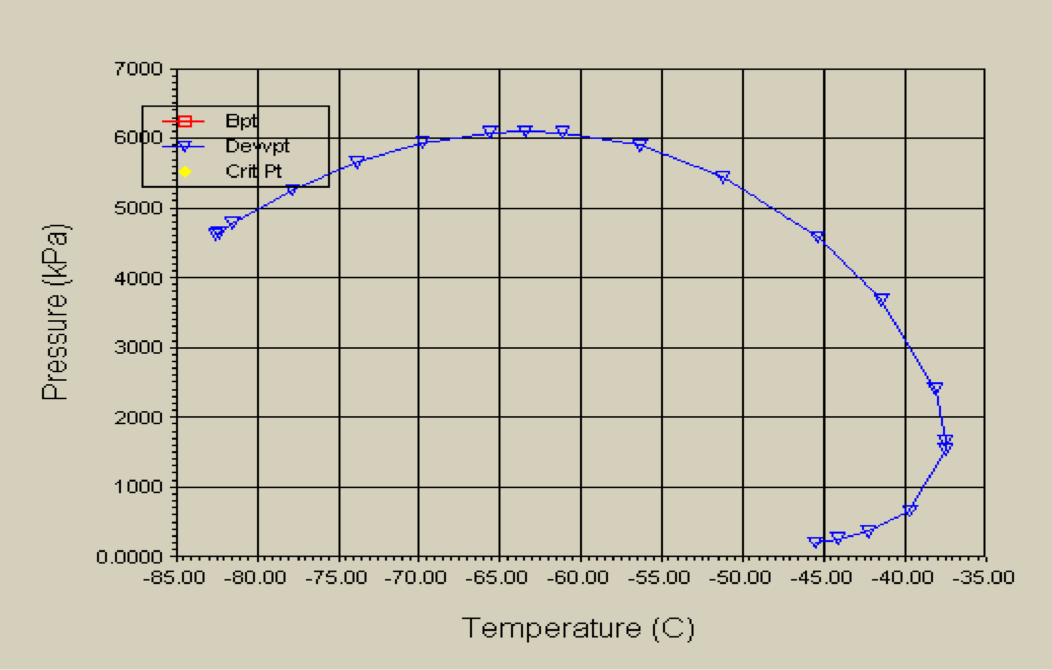

Figure B3: Hydrate Curve for GTL feedgas

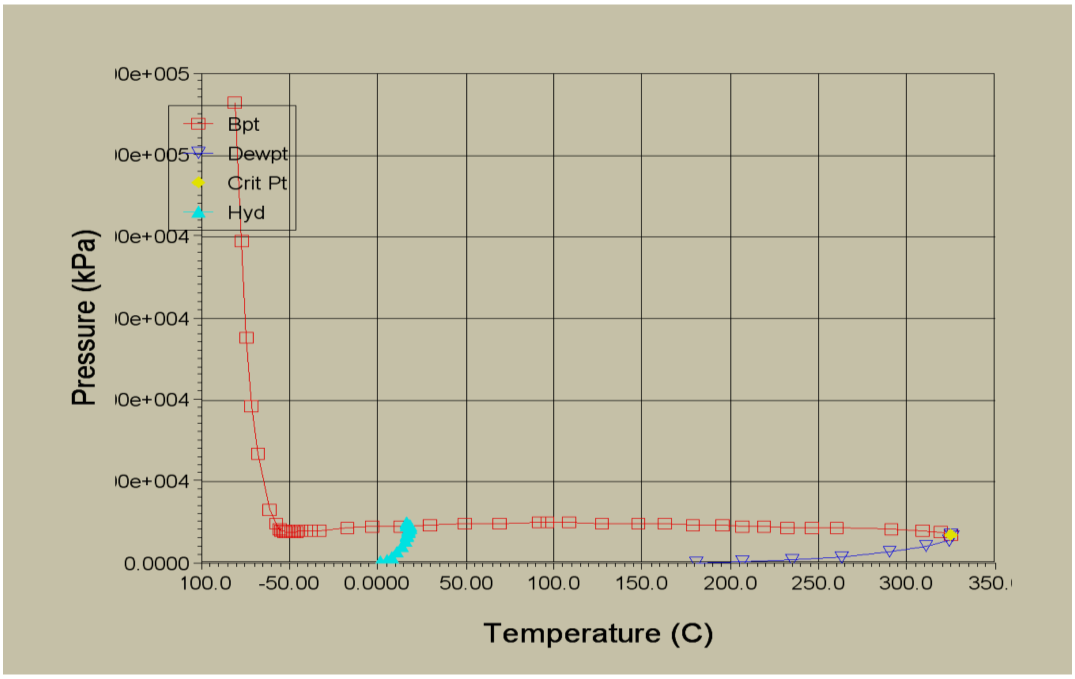

Figure B4: Hydrate Curve for R. feed

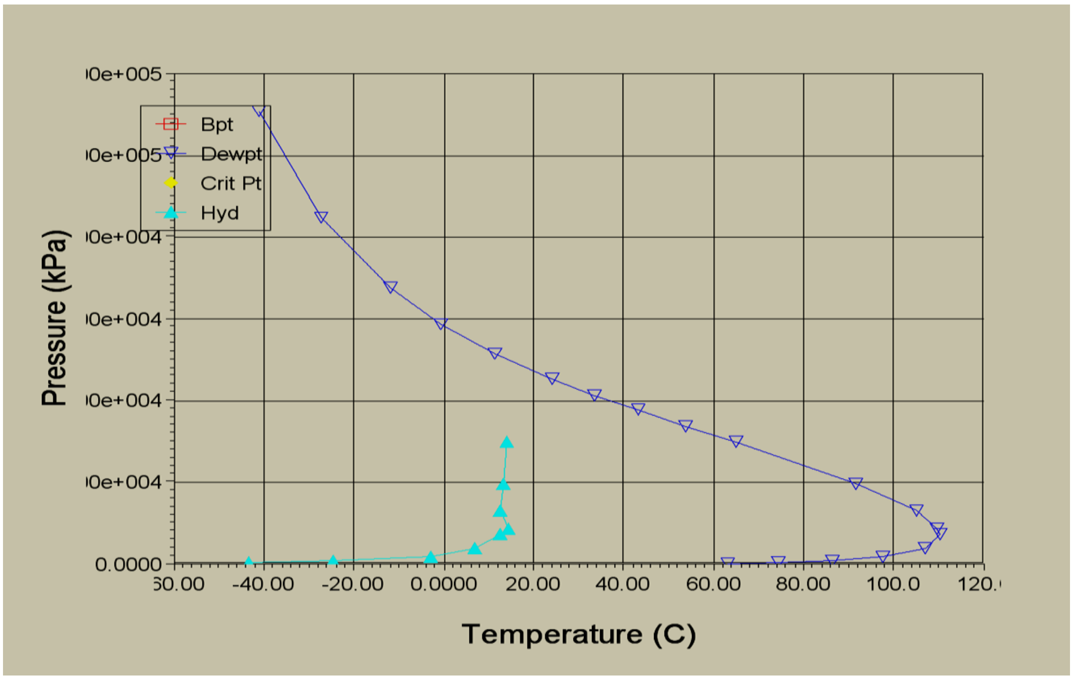

Figure B5: Hydrate Curve for Reg. feed

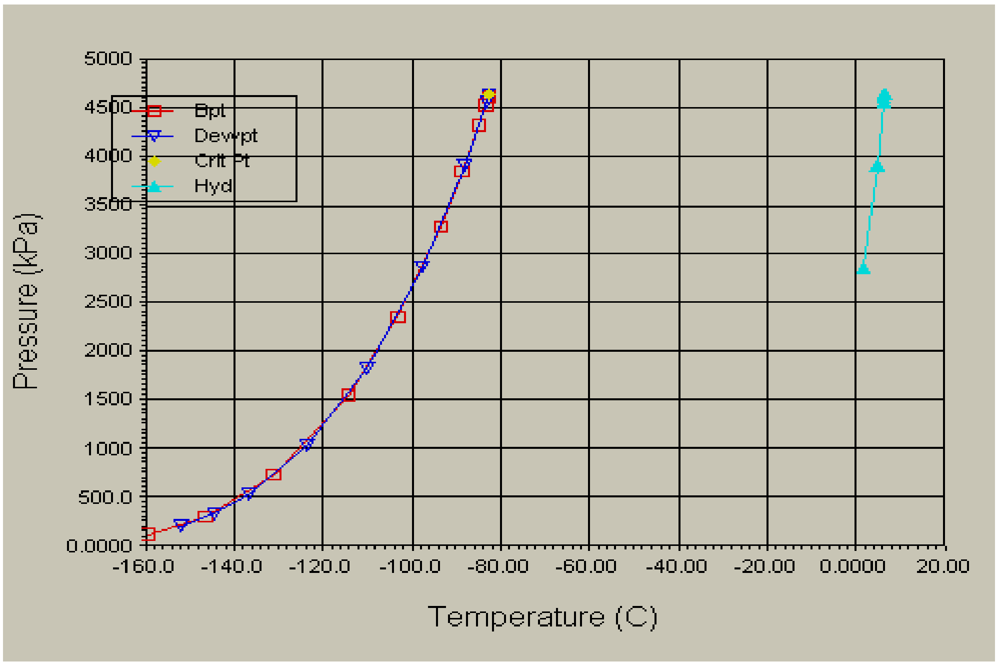

Figure B6: Hydrate Curve for SR feed

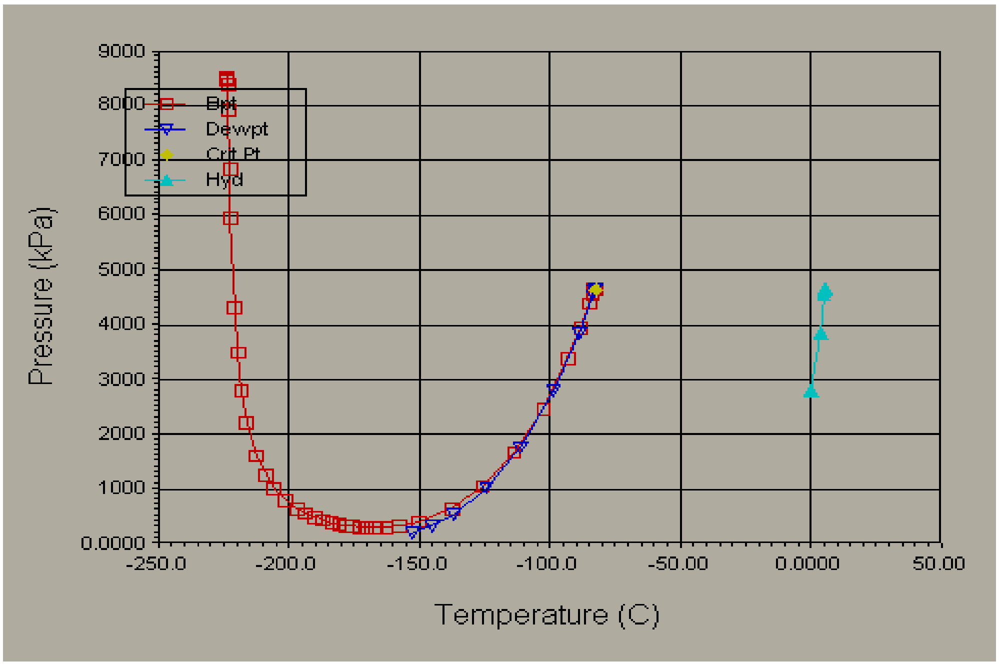

Figure B7: Hydrate Curve for WGS feed

Line Colours and their meaning

Red	Blue	Yellow	Turquoise
Bubble Point line	Dew Point line	Critical Point	Hydrate line