NATURAL GAS DEHYDRATION WITH TRIETHYLENE GLYCOL (TEG)

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Abstract

This work studies the dehydration of natural gas using Triethylene Glycol (TEG)" as the dehydrating agent or absorbent to examine the water content of the natural gas stream when the dehydrating agent and the gas flows in counter current manner in an absorption column and to determine hydrate formation temperature and prevent its occurrence. Also to determine the proper amount of the TEG to be used in other not to flood the contactor (absorber) with it and avoid liquid carry over. The natural gas dehydrating plant was designed and simulated using HYSYS software with Process conditions of 6200kpa and 30^0C and gas flow rate of 10MMSCFD were inputted into the software and simulated. Five different TEG flow rates were used for the simulation. Results obtained shows that Between a TEG rate of 53L/hr and 70L/hr, the water content is between acceptable range (6lb/MMSCFD-7lb/MMSCFD) which is the water content limit in natural gas. Therefore, using a flow rate above 70liters/h will not add any significant financial value to the revenue derived from the sales of the gas rather it will flood the absorber unit.

Keywords: Dehydration; Triethylene Glycol (TEG); Hydrogen Systems (HYSYS); absorption; Counter-current

Introduction

Reservoir fluids generally are saturated with water. The water in the gas can present some problems like formation of solid hydrates which can plug valves and fittings, erosion or corrosion problem (Ikoku, 1992; Etuk, 2007; Abdel Aal, et al., 2003). It becomes very important to reduce the water content in the gas stream to below or within the tolerated limit of 6-7lb/MMSCFD.

Natural gas is a naturally occurring hydrocarbon gas mixture consisting primarily of methane, but commonly includes varying amounts of other higher alkanes and even a lesser percentage of carbon dioxide, nitrogen, and hydrogen sulfides etc .

Presently, about 20 percent of all of the primary energy requirements of the world are provided by natural gas; though it was once an unwanted by-product of crude oil production. This development has been recorded in only a few years with the increased availability of the gas resources from different countries (Ikoku, 1992). Today, natural gas is one of the most important fuels in our life and one of the principle sources of energy for many of our day-to-day needs and activities. It is an important factor for the development of countries that have strong economy because it is a source of energy for household, industrial and commercial use, as well as to generate electricity. Natural gas, in itself, might be considered a very uninteresting gas - it is colorless, shapeless, and odorless in its pure form, but it is one of the cleanest, safest, and most useful of all energy sources (Etuk, 2007). Natural gas is the gas obtained from natural underground reservoirs either as free gas or gas associated with crude oil. It generally contains large amounts of methane along with decreasing amounts of other hydrocarbons (Abdel Aal, et al., 2003). Natural gas is a gaseous fossil fuel. Fossil fuels are essentially the remains of plants and animals and microorganisms that lived millions and millions of years ago. It consists primarily of methane but including significant quantities of ethane, propane, butane, and pentane. Methane is a molecule made up of one carbon atom and four hydrogen atoms, and is referred to as CH_4. Natural gas is considered 'dry' when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydro-carbons are present, the natural gas is 'wet' .The natural gas used by consumers is composed almost entirely of methane. However, natural gas found at the wellhead, although still composed primarily of methane, is by no means a pure gas. Raw natural gas comes from three types of wells: oil wells, gas wells, and condensate wells. Natural gas that comes from oil wells is typically termed 'associated gas'. This gas can exist separate from oil in the formation (free gas), or dissolved in the crude oil (dissolved gas). Natural gas from gas and condensate wells, in which there is little or no crude oil, is termed non-associated gas. Gas wells typically produce raw natural gas by itself, while condensate wells produce free natural gas along with a semi-liquid hydrocarbon condensate. Whatever the source of the natural gas, once separated from crude oil it commonly exists in raw natural gas or sour gas. The raw natural gas contains water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds as shown in Table 1 (Etuk, 2007). The properties of natural gas include gas-specific gravity, pseudo critical pressure and temperature, viscosity, compressibility factor, gas density, and gas compressibility. Knowledge of these property values is essential for designing and analyzing natural gas production and processing systems. Because natural gas is a complex mixture of light hydrocarbons with a minor amount of inorganic compounds, it is always desirable to find the composition of the gas through measurements. Once the gas composition is known, gas properties can usually be estimated using established correlations with confidence (Abdel Aal, et al., 2003).

Table 1: Compositions of raw natural gas (Ikoku, 1992)

Methane	CH_4	70-90%
Ethane	C_2H_6	0-20%
Propane	C_3H_8	0-20%
Butane	C_4H_{10}	0-20%
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen sulphide	H_2S	0-5%
Rare gases	A, He, Ne, Xe	trace

In order to meet the requirements for a clean, dry, wholly gaseous fuel suitable for trans-mission through pipelines and distribution for burning by end users, the gas must go through several stages of processing, including the removal of entrained liquids from the gas, followed by drying to reduce water content. In order to remove water content, dehydration process is used to treat the natural gas. The types of dehydration process used are absorption, adsorption, gas permeation and refrigeration. The most widely dehydration processes used are those which usually involve one of two processes: either absorption, or adsorption. Absorption occurs when the water vapour is taken out by a dehydrating agent. Adsorption occurs when the water vapor is condensed and collected on the surface (Pimchanok Khachonbun, 2013). Gas dehydration is one of the most prominent unit operations in the natural gas industry. In this operation water content is removed from natural gas streams to meet sales specifications or other downstream gas processes such as gas liquid recovery. In particular, water content level in natural gas must be maintained below a certain threshold so as to prevent hydrate formation and minimize corrosion in transmission pipelines. The lifetime of a pipeline is governed by the rate at which corrosion occurs which is directly linked with the present of water content in gas and causes the formation of hydrates which can reduce pipeline flow capacities, even leading to blockages, and potential damage to process filters , valves and compressors (Ikoku, 1992). There are three major methods of dehydration are: direct cooling, adsorption, and absorption (Siti Suhaila Bt Mohd Rohani, 2009). Dehydration by absorption with glycol is usually economically more attractive than dehydration by solid desiccant, though both processes are capable of meeting the required dew point (Abdel Aal, et al., 2003).

Absorption is the transfer of a component from the gas phase to the liquid phase, and is more favorable at a lower temperature and higher pressure. Water vapor is removed from the gas by intimate contact with a hygroscopic liquid desiccant in absorption dehydration. The contact is usually achieved in packed or trayed towers. Glycols have been widely used as effective liquid desiccants. TEG has gained nearly universal acceptance as the most cost effective of the glycols due to its superior dew point depression, operating cost, and operation reliability (Polák, 2009).

In this study, dehydration of natural gas using tri-ethylene glycol(TEG) as a dehydrating or absorption agent were studied considering the use of HYSYS as a process simulator.

Methodology

The design and simulation of the natural gas dehydration plant utilized in this work to achieve the desired objectives. A case study package of the software was used in the analysis; such that different quantity and flow rate of TEG was imposed on the plant to determine the various quantity of water removed.

Process Description

Wet natural gas is first flashed in an inlet separator to remove liquid and solid content. The process condition of the feed stream are; temperature was at 30^{o}C and a pressure of 6200kpa and a flow rate of 500kgmol/h and all the components of the natural gas was used with their various mole fractions, after reducing the liquid content in the separator. The gas stream from separator is dried in contactor unit which is design as an absorber operation using counter current TEG stream, the rich TEG stream coming out from the bottom of the absorber unit passes through the valve to the pressure of the stream and is then feed to shell side of the heat exchanger to raise the temperature through the energy stream coming from the reboiler operation. The heat exchanger is meant to take heat from where is not needed to the places where it is needed. The regeneration operation is carried out using a distillation column to recover fully the TEG against wastage. The stream LEAN FROM L/R as shown in Figure 1 which contain more of TEG to be recycled is flashed in a mixer operation to ensure material balance of the TEG, because some quantities of TEG has been lost during the dehydration . Pump is installed to raise the pressure of the TEG stream before it enters the contactor streams. Another heat exchanger is also added to cool the TEG stream to the contactor stream, but for the purpose of this research work a recycle operation will not be added to be able to feed different amount of TEG and monitor the amount of water removed at each addition of TEG.

The sales Gas is flashed to the component splitter, this will remove completely the TEG in the sales gas because one of the criteria used to determine the efficiency of a dehydration facility is the water dew point of the dry gas. This can easily be checked by finding the temperature at which water will just begin to condense. Therefore all traces of TEG must be removed from the stream to be tested because TEG affects the water dew point.

Simulation

Natural gas dehydrating plant was designed and simulated using HYSYS software.

Aspen HYSYS is a comprehensive Process modeling tool used by the world's leading oil and gas producers, refineries, and engineering companies for process simulation and process optimization in design and operation. The process conditions used in this simulation are those obtained from the SPDC south- south Nigeria.

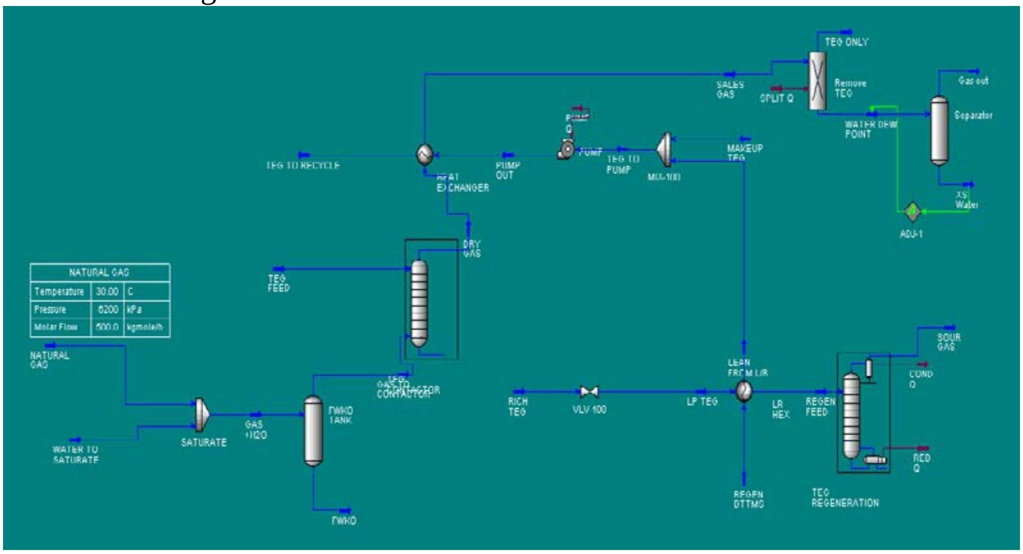

Figure 1: Process Flow Diagram of Natural gas Dehydration Unit

Table 3: Feed Gas Composition and Process Conditions

COMPONENTS	COMPOSITIONS
N_2	0.0010
H_2S	0.0155
CO_2	0.0284
C_1	0.8989
C_2	0.0310
C_3	0.0148
$i\text{-}C_4$	0.0059
$n\text{-}C_4$	0.0030
$i\text{-}C_5$	0.0010
$n\text{-}C_5$	0.0005
H_2O	0.0000
TEG	0.0000
TOTAL	**1.0000**

Table 3: Process conditions values

Temperature	30^0C (85^0F)
Pressure	6200kpa (900psia)
Molar Flow	500 kgmol/h (10MMSCFD)

The composition of the natural gas stream is saturated with water, prior to entering the Contactor. This is to demonstrate the effectiveness of the TEG in the contactor. The gas compositions and conditions are inputted into the software and simulated.

Table 4: Water composition and condition

Temperature	30^0C (85^0F)
Pressure	6200kpa
Molar flow	5000kgmol/h
Composition	1.000

Result and discussion

The pipeline specification of water content in a processed natural gas stream that can be tolerated is 6-7lb/MMSCF (that is 6lb to 7lb of water per million standard cubic feet of processed natural gas). The Gas to Contactor stream has a flow rate of 500.4kgmole/h (9226kg/h), of which the water content is 7.7323kg/h (17.05lb/h). This value is far above the specification for water content in natural gas, therefore, the gas needs to be treated so as to reduce the water content (Total E&P, 1999). 0.07m3/h of TEG was injected into the contactor to counter mix with the natural gas in the contactor. The gas exit stream "Dry gas" has a flow rate of 500kgmole/h (9218kg/h), of which methane has a flow rate of 449.44kgmole/h (7210.3kg/h) and that of water is 0.001652kgmole/h (0.02988kg/h). The recovery of methane is 90%

The pounds per million standard cubic feet of water in the dry gas stream can be calculated as follows:

$$\frac{0.02988kg}{MMSCF} = \frac{0.02988kg}{MMSCF} \times \frac{1lb}{0.454} \times \frac{24h}{1day} = \frac{1.579\ lb}{MMSCF} \quad ....(1)$$

Although, this value is well below the water content specification, but was achieved for a TEG flow rate of 70liters/h but For a flow rate of 53liters/h, the percentage of methane in the dry gas stream remains at approximately 90%, The water content in the dry gas stream is 0.1221kg/h Following the same conversion above the water content is 6.455 lb/MMSCFD in the dry gas stream with a hydrate formation temperature of -24.867^{0}C. These values are within the limit of water content in natural gas stream that can be tolerated, and indicate that the processed gas can be transported through pipeline without hydrate forming in the line.

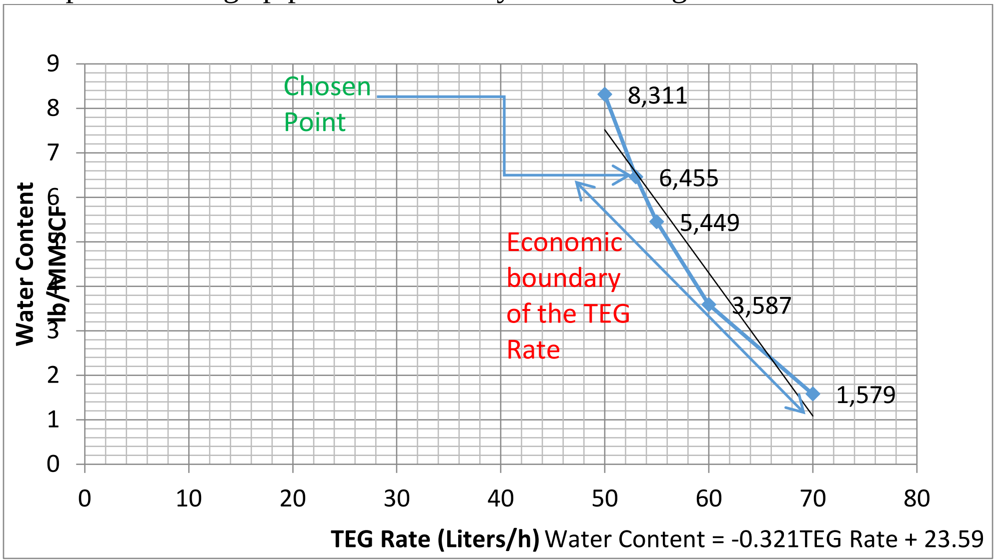

Figure 2: Plot of Water Content against TEG rate

Figure 2 shows an inverse relationship between the TEG rate and the water content. It was observed that high flow rate of TEG absorbed more water present in the natural gas stream while low flow rate absorbed lesser water from the gas stream. Between a TEG rate of 53L/hr and 70L/hr, the water content is between acceptable range (6lb/MMSCFD-7lb/MMSCFD) which is the water content limit in natural gas. Therefore, using a flow rate above 70Liters/hr may not add significant financial value to the revenue derived from the sales of the gas.

Hydrate Formation Analysis

Hydrate formation in process units and in pipelines can impact negatively in the processing of natural gas; it can cause frequent production shutdown, loss of production time, corrosion and increase in operating cost. To avoid these negative impacts, it is necessary to test natural gas streams to determine at what temperature will hydrate form and then carryout the process operation above this temperature (Makogon, Y.A., 1981; Ahmad Syahrul Bin Mohamad,2009**;** Guo and Ghalambor,2005; Ghalambor Et el., 2007)**.** This means that the dry gas stream can be transported safely at temperatures above this value without hydrate forming inside the pipeline. Temperatures at this value and below will cause hydrate to form. To do this, the Hydrate Utility Package in the software was used to carry out test on the dry gas stream to determine the possibility of hydrate formation in the stream. The hydrate formation phase diagrams are shown in the Figures 3-8 below. From Figures 4-8, it could be observed that the hydrate formation temperature decreased with increase in TEG. For a TEG rate of $0.05m^3/h$, $0.053m^3/h$, $0.055m^3/h$, $0.06m^3/h$, $0.07m^3/h$, the hydrate formation temperatures are -22.285^0C, -24.867^0C, -26.612^0C, -30.817^0C and -38.793^0C respectively.

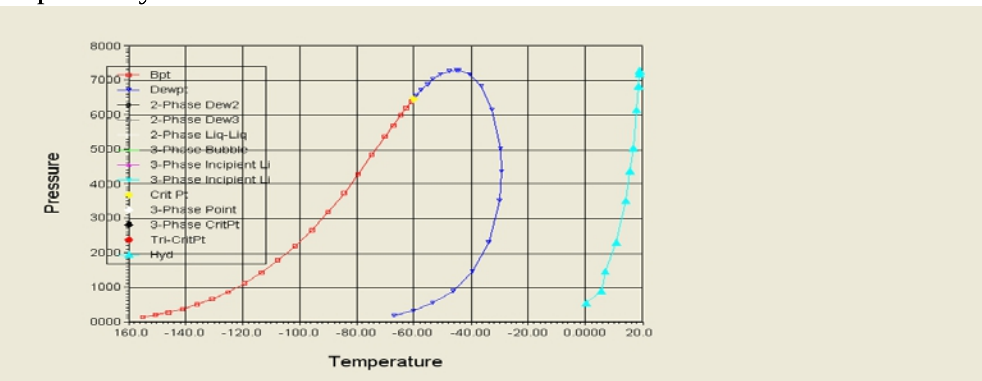

Figure 3: Hydrate formation Temperature of feed gas is 18.1420^0C before dehydration with TEG

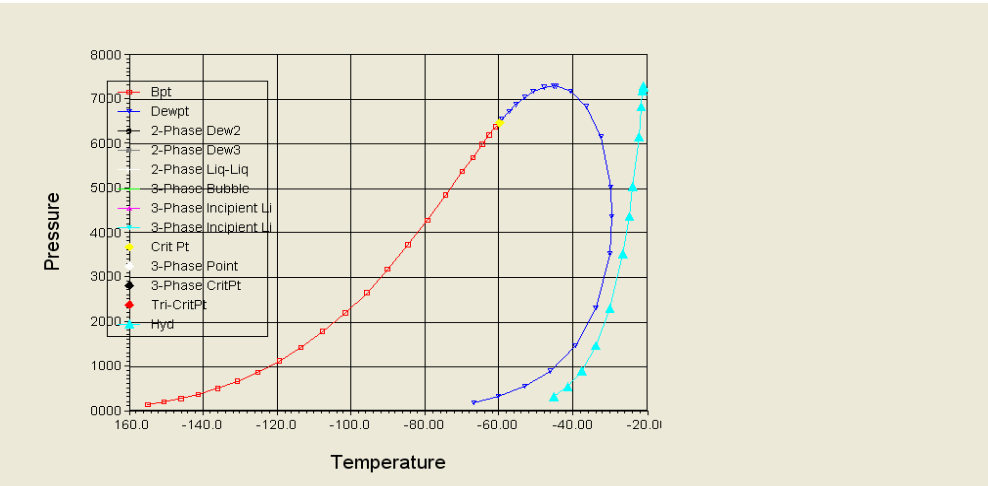

Figure 4: Hydrate formation temperature for TEG volumetric rate of $0.05m^3/h$(50litres/h).

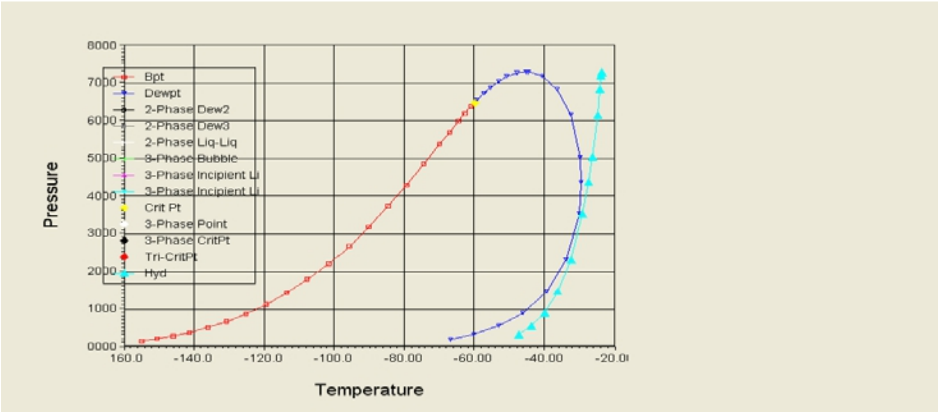

Figure 5: Hydrate formation temperature for TEG volumetric rate of 0.053m^3/h(53litres/h).

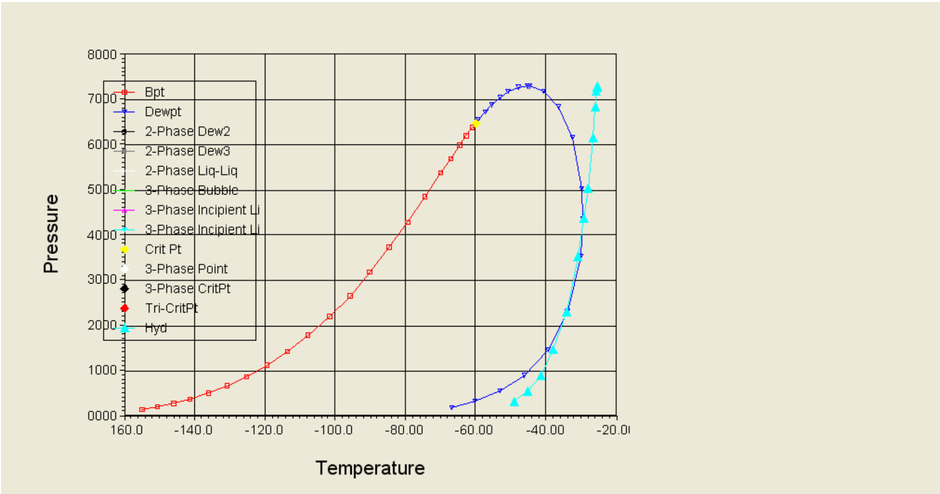

Figure 6 Hydrate formation temperature for TEG volumetric rate of 0.055m^3/h(55litres/h).

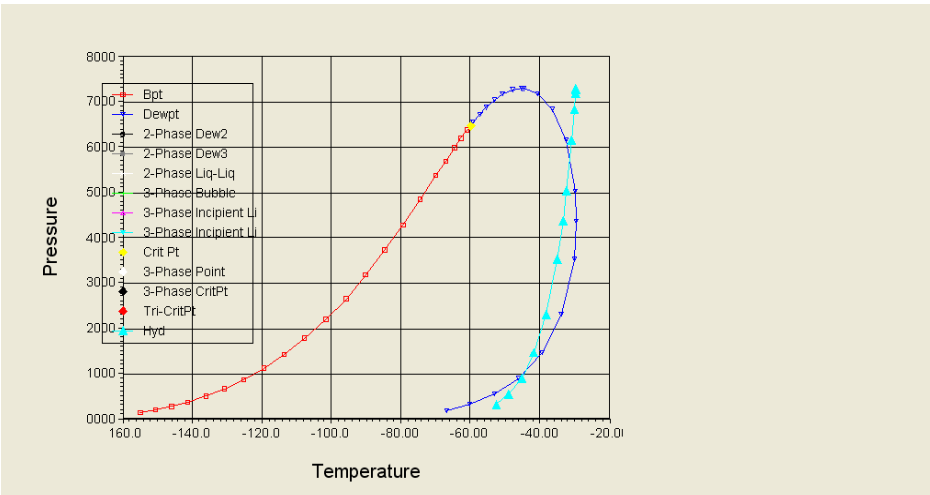

Figure 7: Hydrate formation temperature for TEG volumetric rate of 0.06m^3/h(60litres/h).

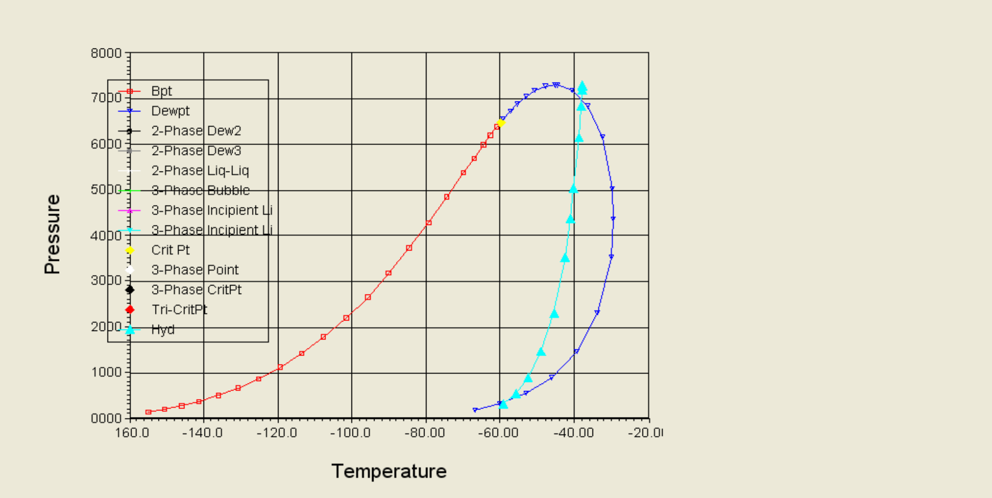

Figure 8: Hydrate formation temperature for TEG volumetric rate of 0.07m^3/h(70litres/h).

Conclusion

Natural gas facilities are designed to handle water removal from the gas stream to meet pipeline specification of water content in the processed gas stream. With the use of HYSYS software, natural gas dehydration plant was designed; process conditions and compositions were inputted and simulated. Results obtained shows that water content in natural gas stream from reservoirs can be reduced to the pipeline specification limit using TEG. However, different water contents in the processed gas stream were obtained for different flow rates of TEG. For the purpose of running the plant economically, the minimum flow rate of TEG which will reduce the water content within the limit of pipeline specification, is very important and the result obtained showed that a minimum of 53Liters/h of TEG is required to reduce the water content of a gas stream of 10MMSCFD to 6.455lb/MMSCFD, which is within the limit of 6-7lb/MMSCFD. Values below this flow rate may not reduce the water content to the specified limit. This will pose threat to process facilities because hydrate formation will occur and this cannot be tolerated when transporting the gas to a region of low temperature.

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