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Simulation of Natural Gas Processing Plant with and without Gas Leaks

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Abstract
The presence of unwanted components such as water vapour, acid gas and nitrogen, in natural gas processing can be detrimental and thus have to be removed or reduced to the barest acceptable standard. Water content and water dew-point are two major parameters used in determining the quality of a processed natural gas. This report focuses on simulating natural gas processing plant which integrates the different processing stages. The simulation of the plant was done using ASPEN process simulator (ASPEN HYSYS software). This was used to model the natural gas flow in two scenarios; the first scenario was without gas leak in the plant and the second scenario was with gas leak in the plant. The results were compared to determine the impact of leak on the quality of the processed natural (dry) gas. It was found out from the simulation that as the volume of gas leak increases, the quality of the gas increases (low water content; low water dew-point; increase mole fraction of methane). Thus, from this simulation, we established a relationship between gas quality and gas leaks in processing plants, which was a very good finding and the target of gas processors.

Keywords: *Gas leak, Gas processing, Gas quality, Water content, Water dewpoint, Methane composition*

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1. Introduction

Natural Gas facilities and installations are susceptible to leakages and rupture accidents as a result of corrosion, material defects, operational errors, age or other reasons which are further aggravated by its high energy and flammable nature (Adenubi *et al*., 2023); Scott and Barruffet, 2003; Wang *et al*., 2001; Lu *et al*., 2014). Though, it is noted severally that leaks in modern natural gas facilities are rare and small relative to the immense volumes of products (Sibray and Hallum, 2016), undetected gas leak produced during operational activities, if not monitored, can lead to undesirable economic loss and could cause toxic air pollution (Appah *et al*., 2021). These leakages may also result into irreversible damages such as financial losses, human casualties, ecological disaster and extreme environmental pollution; most especially if the leakage is not detected promptly (Adegboye, 2019; Baroudi *et al*., 2019). Traditional leak detection approaches for gas facilities are always characterized by sudden changes in facilities and pipeline flowing conditions at the leak site (Stafford and Williams, 1996). These traditional methods variously have their limitations (Sivathanu, 1991), including been prohibitively costly, time-consuming, responses decaying with distance, noise and calibration drifts (Fan *et al*., 2021). Also, many leak detection approaches do not meet industry performance metrics such as sensitivity, reliability, robustness and accuracy (Akinsete and Oshingbesan, 2019). Whereas, measurements of pressure, temperature and flow rates data at both upstream and downstream ends of the facilities are used in developing models to govern the system in detecting leak, locate it and determine the flow rate (Oyedeko and Balogun, 2015). Thus, in gas processing facilities, attempts are made to monitor differentials of all flow parameters (including the gas quality) from one point to the other, and these parameters are related to whether there is a gas leak or not. And the quality of any gas is dependent on the gas water content.

The equipment that makeup a gas processing plant is dependent on the components and compositions of the natural gas. A gas that contains water vapour and acid gases will be treated in a gas plant that has sweetening and dehydration unit, whereas a gas that contains only water vapour will be treated in a gas plant that has only dehydration unit. The later statement is a case with Nigeria gas systems, which contains little or no amount of hydrogen sulphide and as such, most natural gas processing plants in Nigeria have only dehydration units to remove the water vapour. The source of natural gas composition data used in this work was Obite gas plant in Niger Delta region of Nigeria. The design of the plant has only dehydration unit, as indication of the fact that the gas stream has no significant amount of hydrogen sulphide concentration that may require sweetening unit, hence only dehydration unit exist in the process flow diagram.

2. Materials and methods

A process flow diagram was first designed to identify the equipment that makeup the plant and stages in the processing plant. Fig. 1 is the process flow diagram for the natural gas plant used in this report. The Figure clearly identifies the equipment in the gas plant. Fig. 2 is the same natural gas plant, but each unit was clearly identified, to make for easy understanding and flow of information. There are four (4) stages or units in the gas plant, including: pressure control unit; gas, condensate, and free water separation unit; dehydration unit and Tri-ethylene glycol (TEG) regeneration unit.

The first scenario in this report was a gas plant without any gas leak in the gas processing system. This scenario implies that the total gas flow rate into the inlet separator remains unchanged. The second scenario of the simulation was to deliberately initiate a leak in the gas processing plant and determine the impact of the leak on the plant process condition and quality of the dry gas. This scenario implies that the gas flow rate into the inlet separator changes as the leak either increase or decrease. The leak was initiated between the pressure control unit and the gas-condensate-free water separation unit.

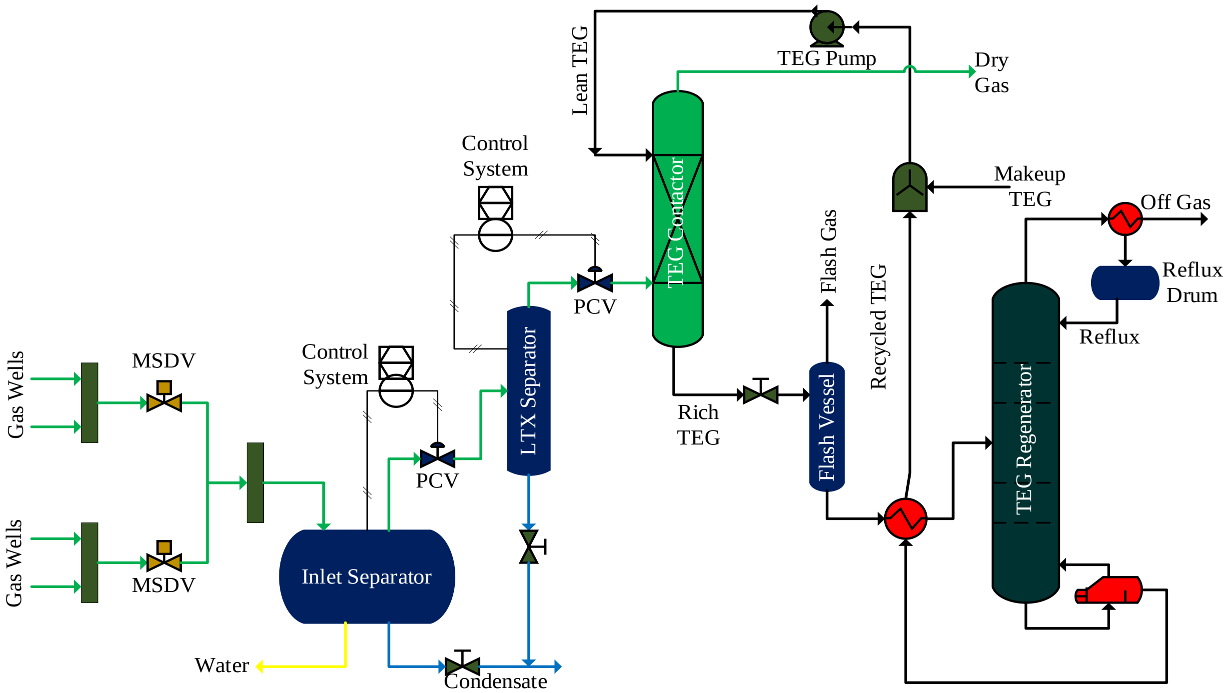

Fig 1: Process flow diagram of natural gas plant with only dehydration unit

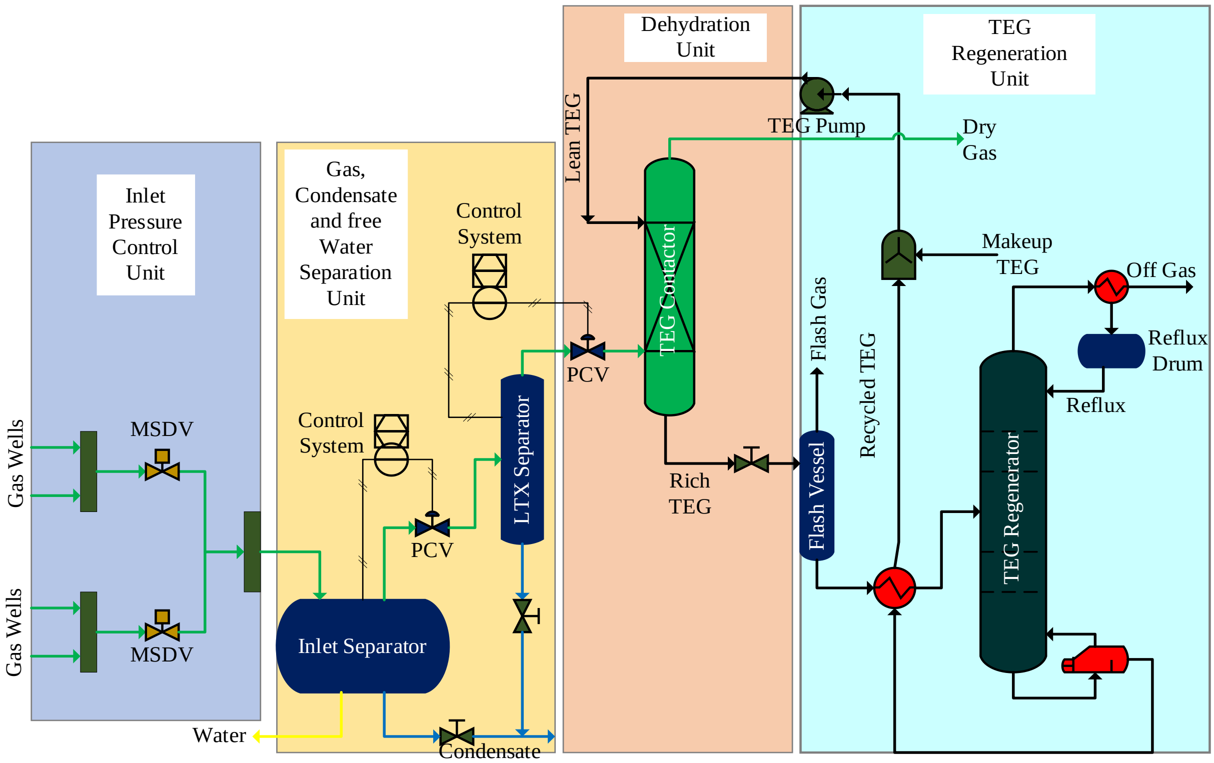

Fig. 2: Process flow diagram showing the different stages of natural gas plant

Natural gas composition from Obite Gas Plant was used as the feed to the natural gas processing plant. Four (4) natural gas streams from different gas wells and their flow parameters formed the initial gas streams entering the gas processing plant through a pressure control unit (manifold). The gas compositions are given in Table 1. The wells are designated alphabetically and the wells selected for the simulation are Well P to Well S. The flow conditions of the wells are given in Table 2. Four gas flow lines were designed and simulated with ASPEN HYSYS simulator to carry the gas from the wells to the pressure control unit. The Aspen HYSYS software used substitutes a physical system into a mathematical model fully illustrated in the simulation environment by a virtual one. It facilitates computer-aided modeling and analyses of processing facilities in a virtual environment, with the building, sizing and costing of equipment and plant optimization without the dangers, costs and risks of a pilot unit (Partho and Ruhul, 2011).

Table 1: Composition of the natural gas entering the processing plant

Component	**Gas Well P (mole %)**	**Gas Well Q (mole %)**	**Gas Well R (mole %)**	**Gas Well S (mole %)**
Comp Mole Frac (Methane)	75.41	73.51	75.77	77.13
Comp Mole Frac (Ethane)	7.06	5.58	6.41	5.84
Comp Mole Frac (Propane)	4.04	4.73	3.82	3.44
Comp Mole Frac (i-Butane)	0.85	1.1	0.9	0.7
Comp Mole Frac (n-Butane)	1.38	1.7	1.7	1.26
Comp Mole Frac (i-Pentane)	0.59	0.76	0.7	0.5
Comp Mole Frac (n-Pentane)	0.52	0.61	0.59	0.46
Comp Mole Frac (n-Hexane)	1.14	1.28	1.2	0.58

Comp Mole Frac (n-Heptane)	1.28	1.31	1.25	1.12
Comp Mole Frac (n-Octane)	0.99	1.03	0.9	1.18
Comp Mole Frac (n-Nonane)	0.64	0.66	0.6	0.7
Comp Mole Frac (n-Decane)	0.36	0.39	0.36	0.49
Comp Mole Frac (n-Undecane)	1.52	2.99	1.56	2.38
Comp Mole Frac (Water)	0.2	0.27	0.31	0.49
Comp Mole Frac (Nitrogen)	0.44	0.22	0.34	0.04
Comp Mole Frac (Carbon dioxide)	3.58	3.83	3.58	3.69
	100	**99.97**	**99.99**	**100**

Table 2: Process flow condition of the four gas wells

Flow Condition	**Gas Well P**	**Gas Well Q**	**Gas Well R**	**Gas Well T**
Temperature (F)	89.6	95	104	95
Pressure (psia)	1450.377	1595.4147	1595.4147	1740.4524
Flow Rate (MMScfd)	200	220	180	210

The simulation is shown in the following figures: Fig. 3 shows the simulated Process Flow Diagram without leak while Fig. 4 shows the simulated Process Flow Diagram with leak spot introduced into the system at the inlet separator to control the pressure and liquid level of the separator. The design and simulation of the gas plant initially started with a steady state. However, to understand the behaviour of the gas plant with respect to changes in process conditions, the steady state simulation was extended to dynamic simulation. The two scenarios stated earlier (gas plant without leak and gas plant with leaks) were done based on dynamic simulation of the process plant, to find out the impact of the leaks on the quality of the processed natural gas. The dynamic control system was designed and simulated on the inlet separator to control the pressure and liquid level of the separator. The reason for the choice of the inlet separator was the fact that liquid carryover due to rise in liquid level above set point and low vessel pressure may occur and will affect the quality of the gas exiting the separator. Therefore, a proper set point of 45% liquid level and 500 psia vessel pressure were used for the dynamic simulation.

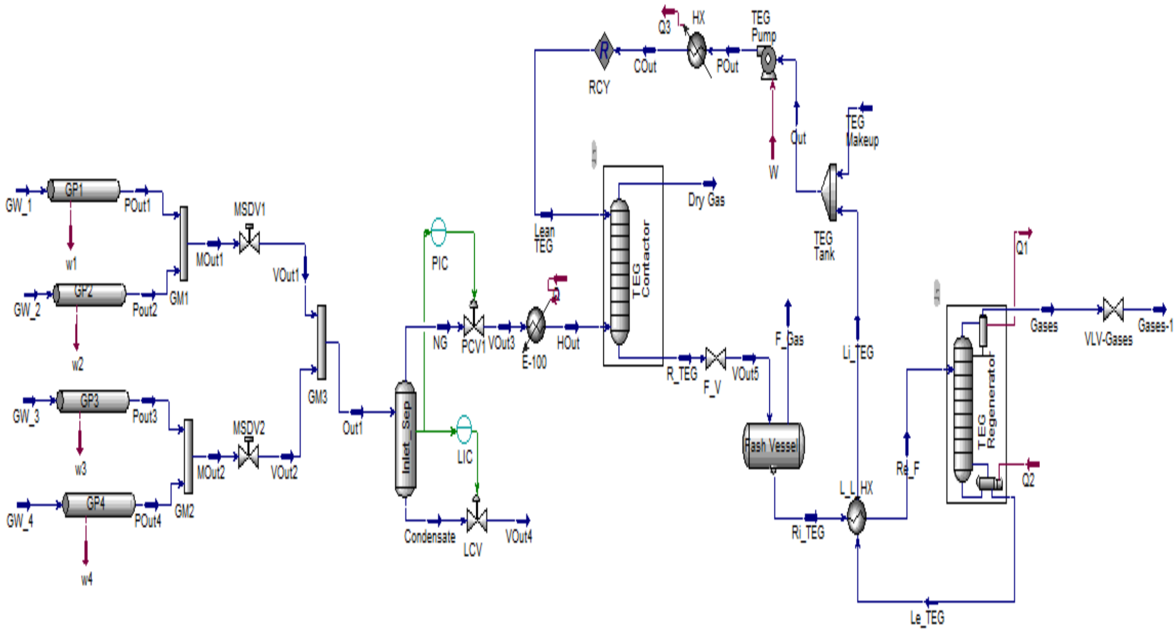

Fig. 3: Simulated process flow diagram without leak

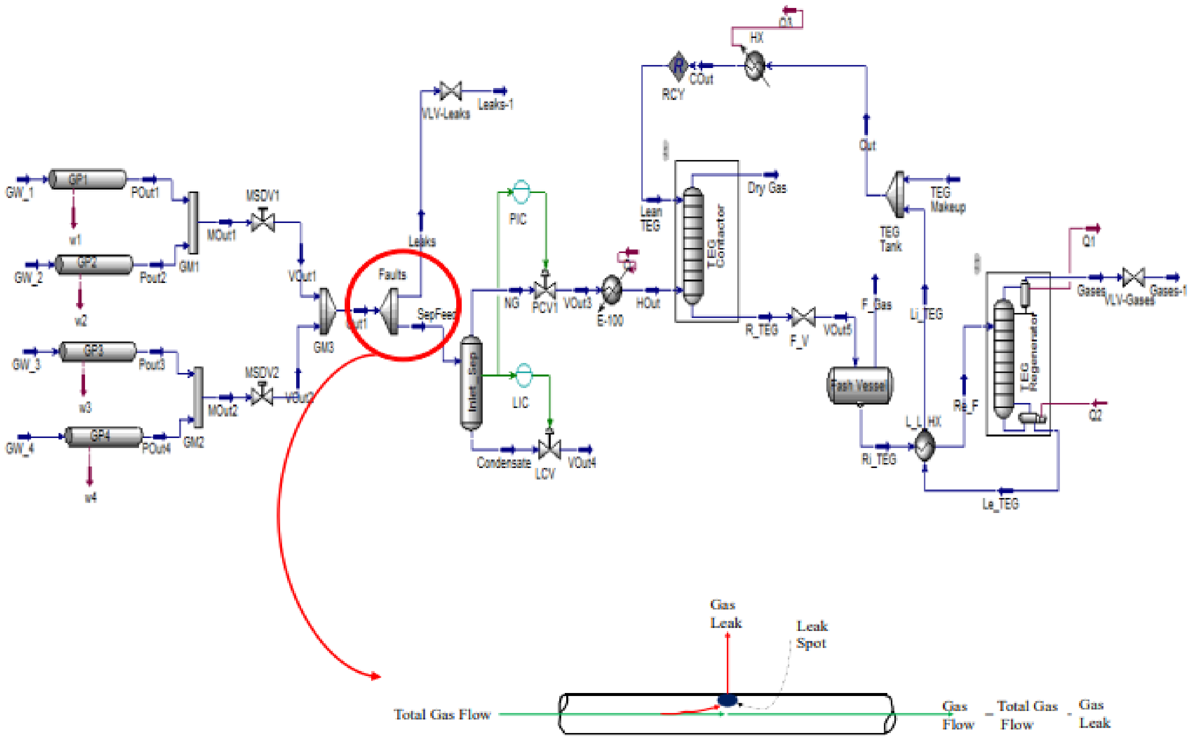

Fig. 4: Simulated process flow diagram with leak spot

3. Results and discussion

The results from the simulation are presented below. The simulation process involved investigations of the responses of the gas stream to different scenarios such as pipeline topology changes with respect to pipe friction, static and acceleration forces; response of the gas flow in the gas pipeline with respect to pressure and heat transfer and finally an investigation into the possibility of a relationship between the volume of gas leaking out from the pipe and the water content; water dew point and mole fraction of methane in the processed gas. The four gas flowlines profiles are given in Fig. 5 to Fig. 8. These Figures are plots of pressure gradient against pipe length. It is an indication of the response of the gas stream through the gas pipes as the pipe line topology changes with respect to pipe friction; static and acceleration forces.

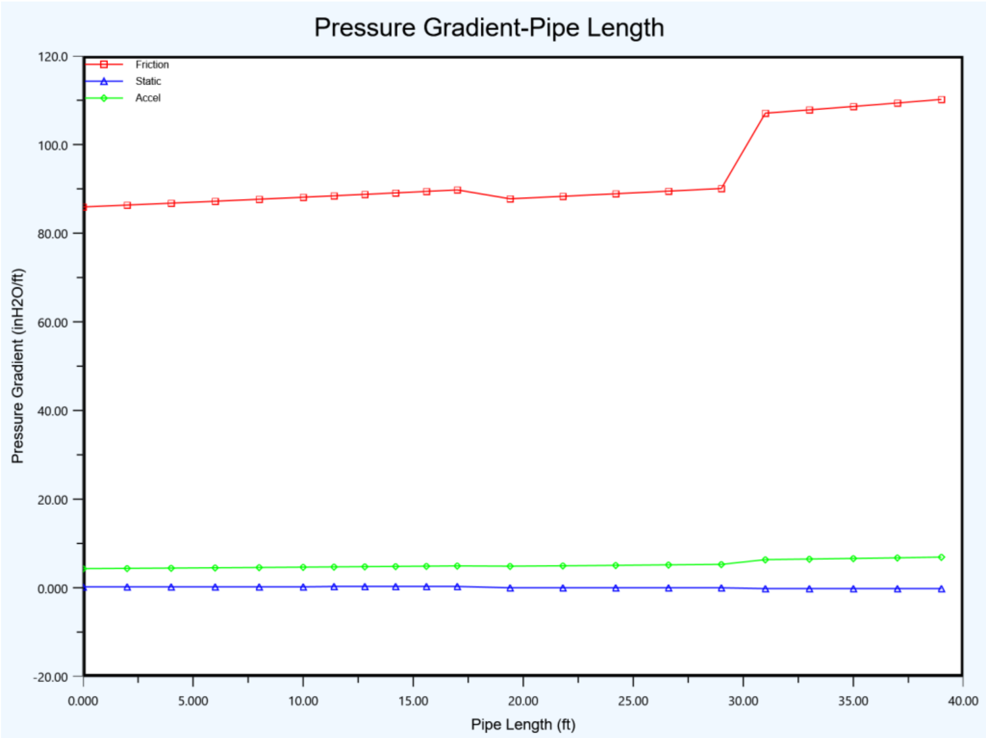

Fig. 5: Pressure gradient for gas pipe GP1

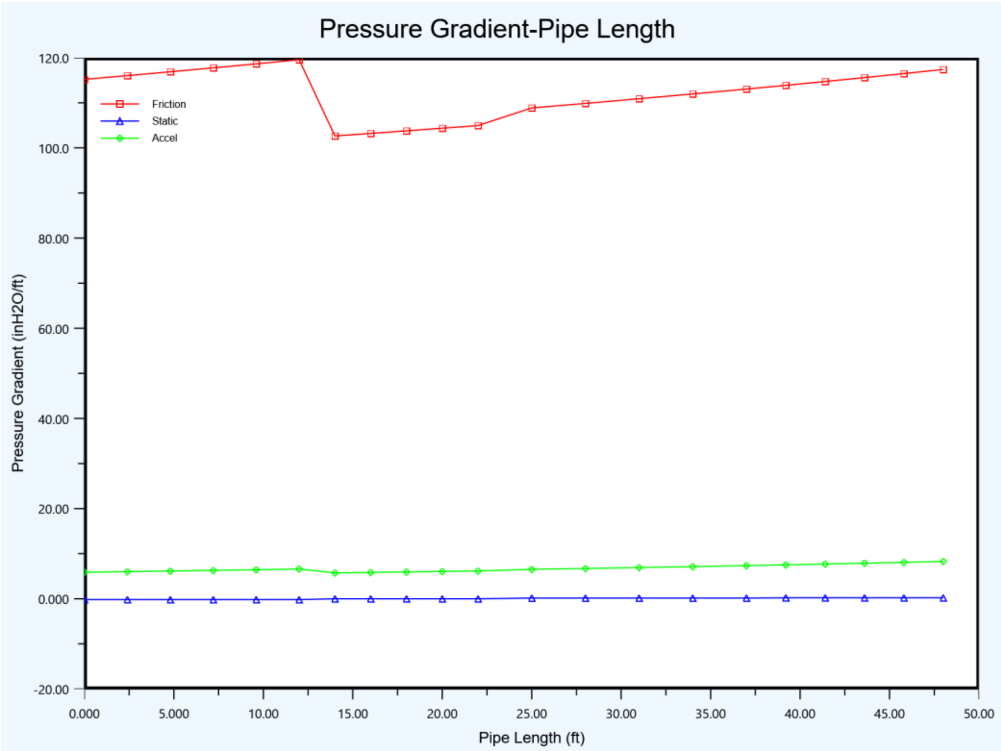

Fig. 6: Pressure gradient for gas pipe GP2

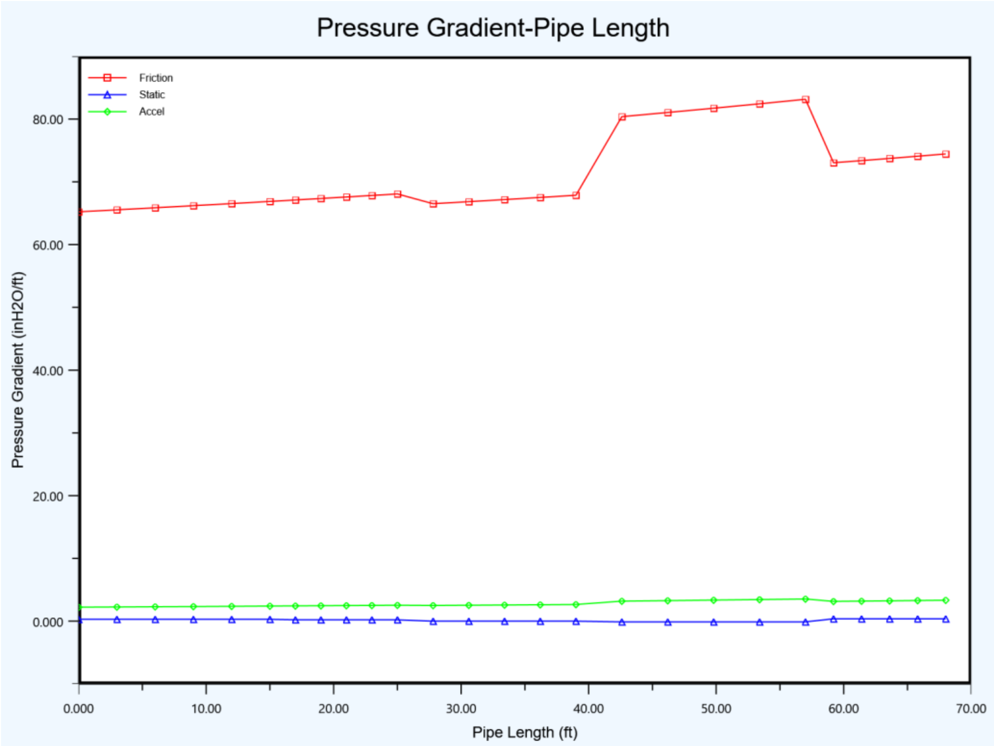

Fig. 7: Pressure gradient for gas pipe GP3

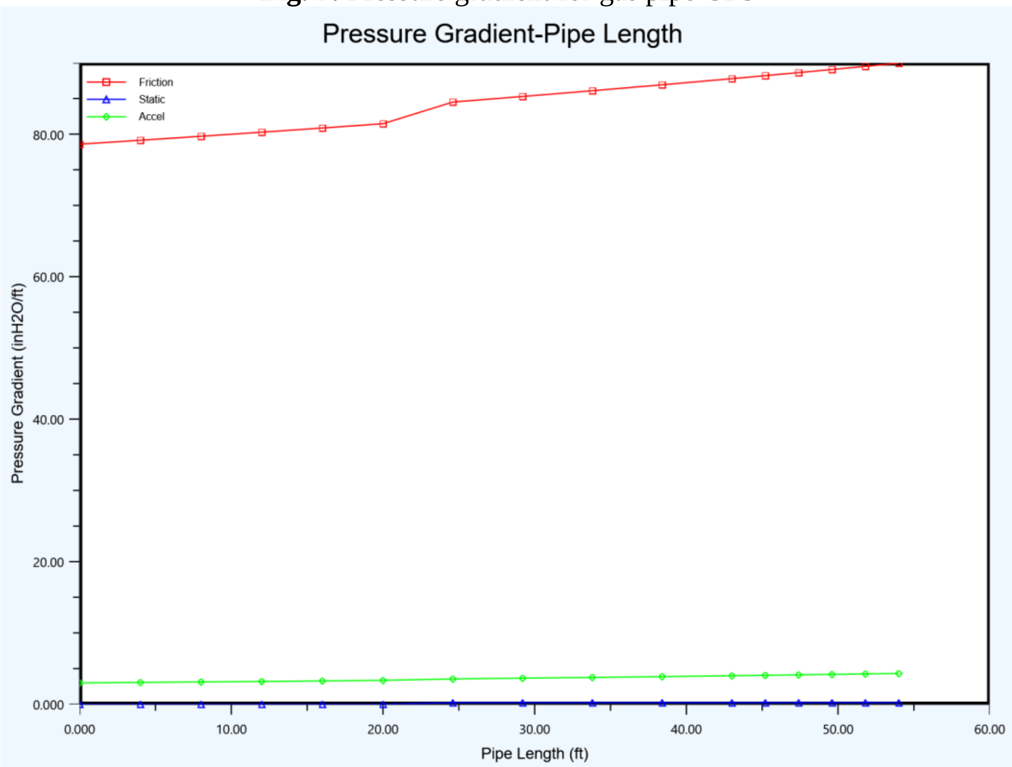

Fig. 8: Pressure gradient for gas pipe GP4

The response of the gas flow in the gas pipeline with respect to pressure and heat transfer was also investigated by observing the rate at which the gas pipeline topology changes with respect to pipe friction; static and acceleration forces. The essence of this investigation was to observe the behaviour of heat transfer as the gas flow through the pipeline. Fig. 9 to Fig. 12 show the plots of pipeline pressure and heat transfer against pipe elevation. The four gas streams, through the manifold, enter the inlet separator where gas, condensate and free water are separated to allow for the separated gas stream to enter the dehydration unit. TEG solvent is particularly employed in the industry to absorb water vapour from natural gas stream, because of its degree of absorption, minimal loss due to vapourization during regeneration. The TEG flow conditions used in the simulation of this report are very close to those used in the Niger Delta gas plant for producing dry gas stream. The TEG specifications are: 24 m^3/hr flow rate, 580 psia pressure and 68°F. The composition of dry gas from the gas plant has in the range of 0.84 to 0.87 mole fraction of methane. The methane composition of the simulation in this report falls in this range.

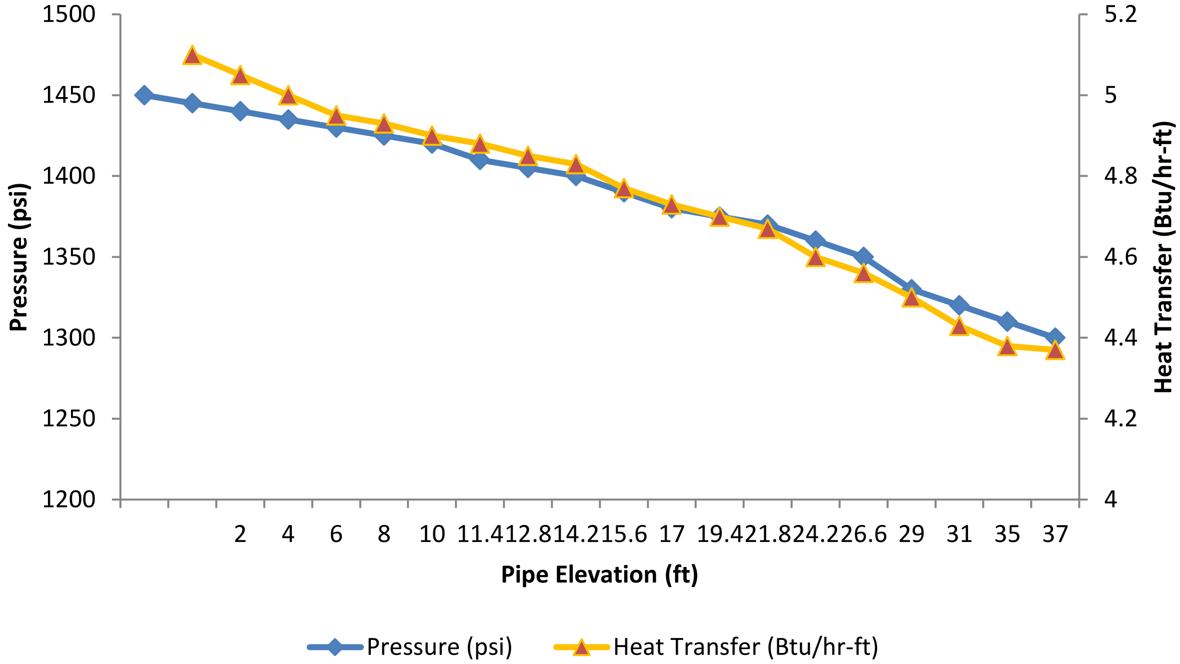

Fig 9: Pressure and Heat transfer profile vs pipe elevation for GP1

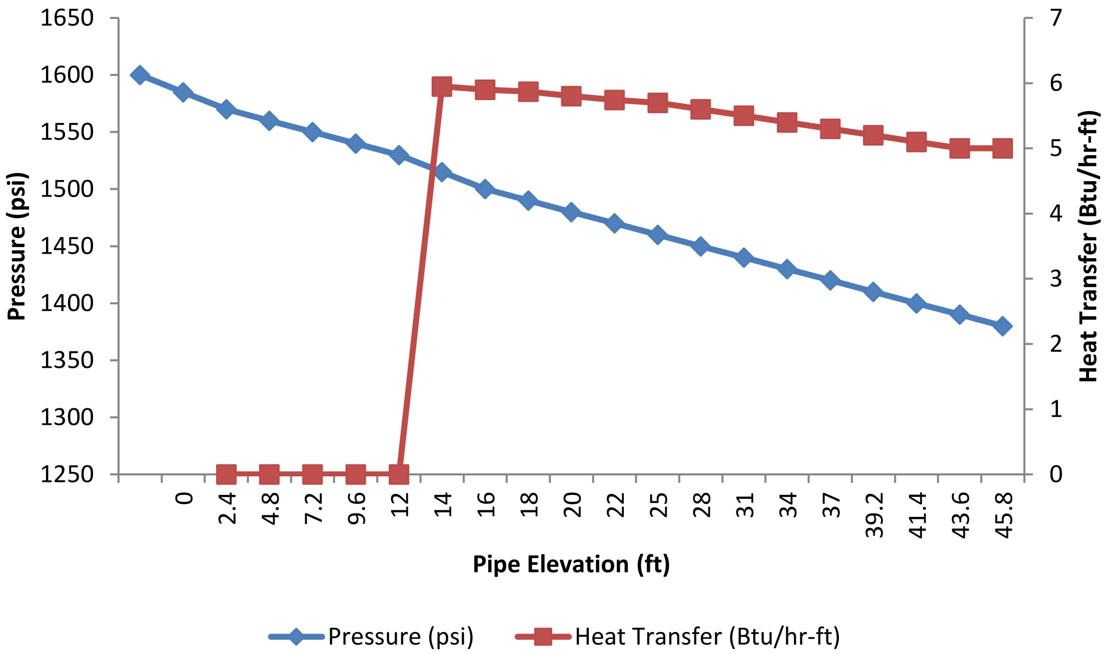

Fig. 10: Pressure and heat transfer profile vs pipe elevation for GP2

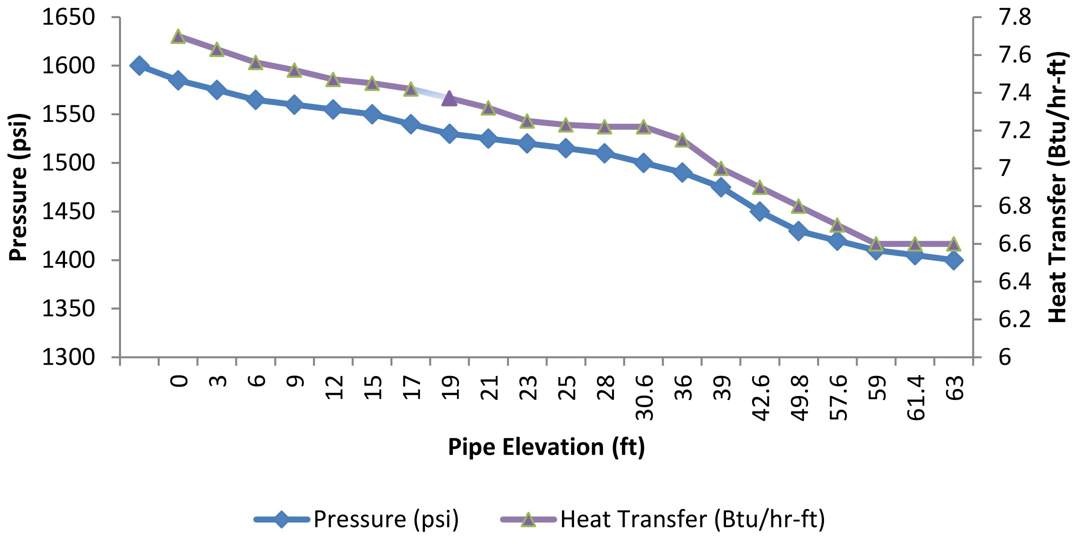

Fig. 11: Pressure and heat transfer profile vs pipe elevation for GP3

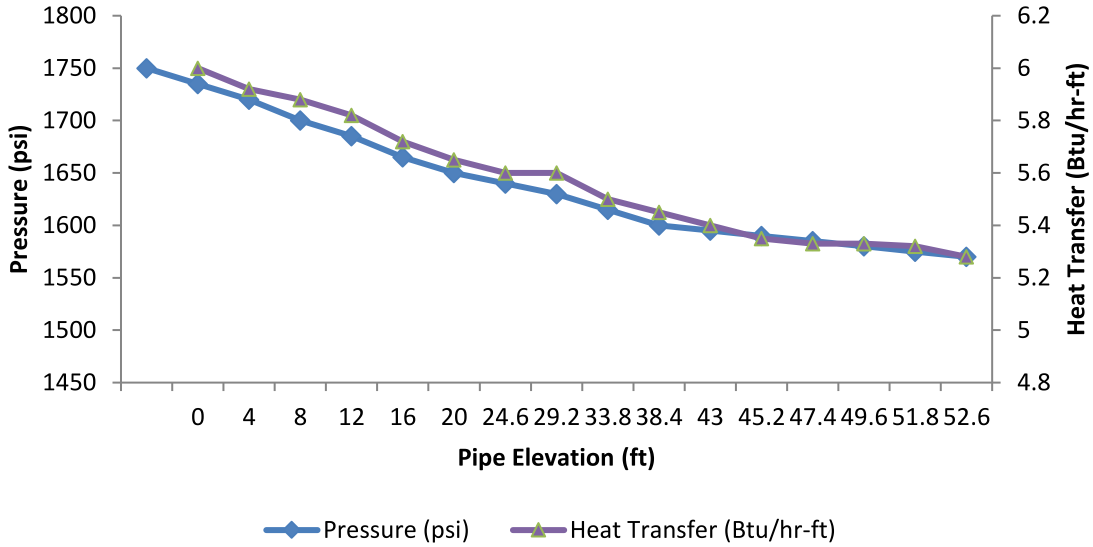

Fig. 12: Pressure and heat transfer profile vs pipe elevation for GP4

The dehydration unit was designed and simulated at maximum pressure of 800 psia (55.16 bar) and temperature of 140°F (60°C), which agrees with the values quoted by Jacob (2014), that a typical absorber column operates effectively at pressure in the range of 40 bar to 80 bar and temperature in the range of 20°C to 60°C. However, as an engineering practice, an optimum mole fraction of methane in the dry gas stream was investigated in the simulation using "Case Study" package in the software. To do this a function was defined as given in Equation (1).

$$y_{CH_4} = f\left(\Delta P_{sep}\right) \quad (1)$$

where y_{CH_4} is the mole fraction of methane in the dry gas stream and ΔP_{sep} is the separator pressure drop. This function equation was entered into the case study package to determine the optimum mole fraction of methane for a given inlet separator pressure drop. The aspect of water content and water dew point in natural gas contract determines the extent of raw natural gas treatment. In this simulation of natural gas plant, the water content and water dew point were put into consideration and were obtained from the simulation without gas leak and with gas leak.

The rich TEG was routed to the regeneration unit, to strengthen its activities (absorption efficiency) through regeneration. According to Netusil and Ditl (2012), the circulation of lean TEG should not contain less than 95% TEG and that a good design should contain 98% to 99% of TEG. The regeneration unit was designed and operated at an average temperature of 384ºF (196ºC) and 2 bar. Maurice and Ken (2011) stated that TEG is re-concentrated in the regenerator unit at temperature range of 350ºF (177ºC) to 400ºF (204ºC) and 1 bar pressure, which yield TEG purity of 98.8%. The process description above is applicable to both the first and second scenarios, except the point where the leak was initiated. Fig. 13 and Fig. 14 show the simulated process flow diagram without leak and with leak. The material and composition of the most important stream were selected in this report and are presented in Table 3 and Table 4. In order to allow easy flow of information and understanding of the progressive changes in material streams and composition of the streams, as the gas flow from left to right, the nomenclatures in the simulated process diagram were retained in the Tables. Table 3 and Table 4 were acquired process data before initiating the leak. As shown in Figure 13, before initiating the leak, the simulation produced dry gas ("Dry Gas") with 0.8494 mole fraction of methane (Table 4). The temperature and pressure were 124.4ºF and 551 psia (Table 3). In addition, data for the water content and water dew point were acquired from the simulation and they are 0.04923 lb/MMScf and -48.54ºF (-44.74ºC) respectively, at the "Dry Gas" temperature and pressure of 124.4ºF (51.33ºC) and 551 psia.

Table 3: Process condition for material streams

	Unit	**GW_1**	**GW_2**	**GW_3**	**GW_4**	**Out1**	**NG**	**Condensate**
Vapour Fraction		0.835317	0.773197	0.837478	0.8208879	0.826314	1	0
Temperature	*F*	89.6	95	104	95	87.29449	68.39407	68.39406684
Pressure	*Psia*	1450.377	1595.415	1595.415	1740.4524	1304.211	794.9114	794.9114066
Molar Flow	*MMSCFD*	200	220	180	210	810	687.6398	122.360195
Mass Flow	*lb/day*	14198823	17187436	12795437	15212193	59393888	35715540	23678348.19
Liquid Volume Flow	*m3/h*	652.6154	748.2981	586.6649	689.50735	2677.086	1964.438	712.6481198
Heat Flow	*kW*	-287342	-333991	-258534	-309245.5	-1189115	-868177	-320938.413

Table 3: Process Condition for Material Streams Cont.

	Unit	**Lean TEG**	**Dry Gas**	**R_TEG**	**Re_F**	**Gases**	**Le_TEG**
Vapour Fraction		0	1	0	0.0015587	1	0
Temperature	*F*	68	124.389	141.1797	302	241.1062	608.5169
Pressure	*Psia*	580	551.1433	797.7073	362.59425	14.50377	29.00754
Molar Flow	*MMSCFD*	3.620994	687.102	4.158772	4.1071733	0.48718	3.619993
Mass Flow	*lb/day*	1432976	35682214	1466301	1463402.3	30822.79	1432580
Liquid Volume Flow	*m3/h*	24	1963.516	24.92173	24.771143	0.777778	23.99336
Heat Flow	*kW*	-41174.8	-848776	-42074.9	-39941.59	-1509.699	-34050.5

Table 4: Composition of the different stream

Component	**GW_1**	**GW_2**	**GW_3**	**GW_4**	**Out1**	**NG**	**Condensate**
Comp Mole Frac (Methane)	0.7541	0.73532	0.75778	0.7713	0.7542755	0.8488692	0.22267782

Comp Mole Frac (Ethane)	0.0706	0.05582	0.06411	0.0584	0.0619788	0.061327	0.06564209
Comp Mole Frac (Propane)	0.0404	0.04731	0.0382	0.0344	0.0402343	0.030879	0.09280944
Comp Mole Frac (i-Butane)	0.0085	0.011	0.009	0.007	0.0089023	0.0049536	0.03109355
Comp Mole Frac (n-Butane)	0.0138	0.01701	0.017	0.0126	0.0150709	0.0070912	0.05991506
Comp Mole Frac (i-Pentane)	0.0059	0.0076	0.007	0.005	0.0063736	0.0017962	0.03209801
Comp Mole Frac (n-Pentane)	0.0052	0.0061	0.0059	0.0046	0.0054451	0.0012763	0.02887253
Comp Mole Frac (n-Hexane)	0.0114	0.0128	0.012	0.0058	0.010463	0.0010779	0.06320544
Comp Mole Frac (n-Heptane)	0.0128	0.0131	0.0125	0.0112	0.0124013	0.0005301	0.07911556
Comp Mole Frac (n-Octane)	0.0099	0.0103	0.009	0.0118	0.0103023	0.0001819	0.06717687
Comp Mole Frac (n-Nonane)	0.0064	0.0066	0.006	0.007	0.0065217	0.00	0.04290872
Comp Mole Frac (n-Decane)	0.0036	0.0039	0.0036	0.0049	0.0040189	0.00	0.02653607
Comp Mole Frac (n-undecane)	0.0152	0.02991	0.0156	0.0238	0.0215139	0.00	0.14226762
Comp Mole Frac (water)	0.002	0.0027	0.0031	0.0049	0.0031867	0.0005439	0.01803885
Comp Mole Frac (Nitrogen)	0.0044	0.0022	0.0034	0.0004	0.0025435	0.0029419	0.00030408
Comp Mole Frac (carbon dioxide)	0.0358	0.03831	0.0358	0.0369	0.0367681	0.0384461	0.02733828
Comp Mole Frac (TEGlycol)	0	0	0	0	0	0	0

Table 4: Composition of the different stream cont.

Component	**Lean TEG**	**Dry Gas**	**R_TEG**	**Re_F**	**Gases**	**Le_TEG**
Comp Mole Frac (Methane)	0.00	0.84943	0.01784	0.00817	0.0688481	0.00
Comp Mole Frac (Ethane)	0.00	0.06136	0.00313	0.00219	0.018462	0.00
Comp Mole Frac (Propane)	0.00	0.03088	0.00314	0.00264	0.0222569	0.00
Comp Mole Frac (i-Butane)	0.00	0.00494	0.00304	0.00299	0.0251809	0.00
Comp Mole Frac (n-Butane)	0.00	0.00709	0.0008	0.00069	0.0058421	0.00
Comp Mole Frac (i-Pentane)	0.00	0.00179	0.00181	0.0018	0.0151569	0.00
Comp Mole Frac (n-Pentane)	0.00	0.00128	0.00029	0.00027	0.0023005	0.00
Comp Mole Frac (n-Hexane)	0.00	0.00107	0.00067	0.00067	0.005621	0.00
Comp Mole Frac (n-Heptane)	0.00	0.00053	0.00056	0.00056	0.0047446	0.00
Comp Mole Frac (n-Octane)	0.00	0.00018	0.00036	0.00036	0.0030649	0.00
Comp Mole Frac (n-Nonane)	0.00	0.00	0.00015	0.00015	0.0012656	0.00
Comp Mole Frac (n-Decane)	0.00	0.00	0.00	0.00	0.0005337	0.00
Comp Mole Frac (n-Undecane)	0.00	0.00	0.00022	0.00022	0.0018923	0.00

Comp Mole Frac (water)	0.00	0.00	0.08977	0.09089	0.7661428	0.00
Comp Mole Frac (Nitrogen)	0.00	0.00294	0.00	0.00	0.00	0.00
Comp Mole Frac (carbon dioxide)	0.00	0.03843	0.00762	0.00687	0.0579573	0.00
Comp Mole Frac (TEGlycol)	0.99998	0.00	0.87052	0.88145	0.0007062	0.9999848

The result for optimum mole fraction of methane in the dry gas was plotted in Fig. 14. The plot was mole fraction of methane against pressure drop in the vessel. The optimum value of the mole fraction was found to be 0.8499 for optimum pressure drop of 510 psia. Leak was initiated upstream of the inlet separator. The leak was designed and simulated such that 0.05 fraction of the total gas flow was allowed to leak out from the pipe and 0.95 fraction flows into the inlet separator, making the total gas flow drop from 810 MMScfd to 769.6 MMScfd. The dynamic state of the process flow diagram was simulated with the leak, and the behavior or response of the system during gas leak was observed. When the leak was initiated with the above fractions, the methane composition of the "Dry Gas" stream remained almost the same with the composition without leak, but the water content and water dew point dropped to 0.03181 lb/MMScf and -56.04°F (-48.91°C) respectively, due to drop in gas flow rate from 810 MMScfd to 769.5 MMScfd.

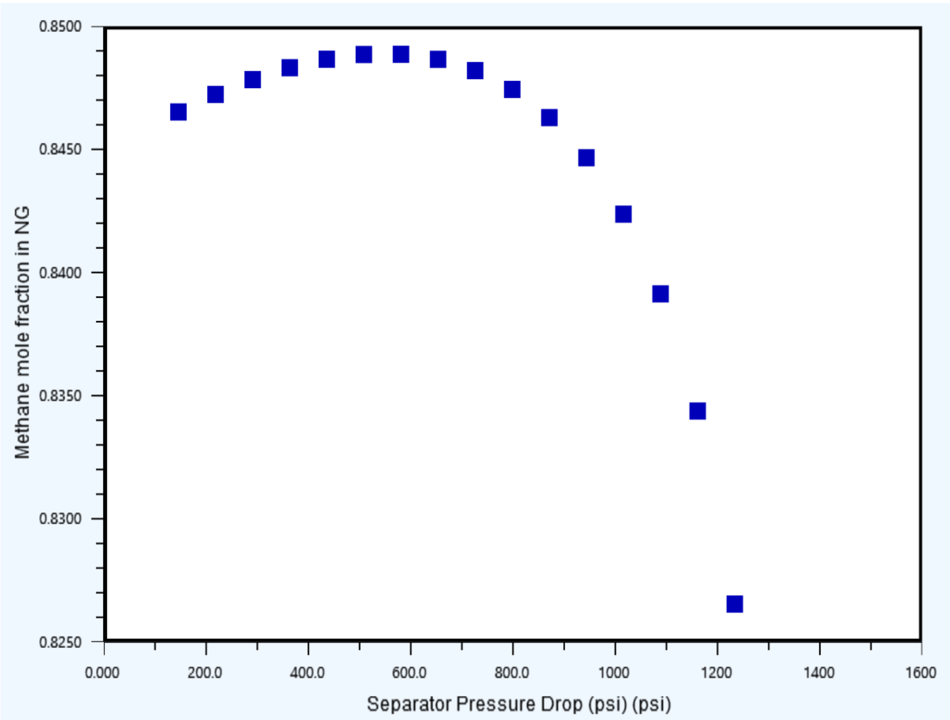

Fig. 13: Optimum mole fraction in dry gas stream

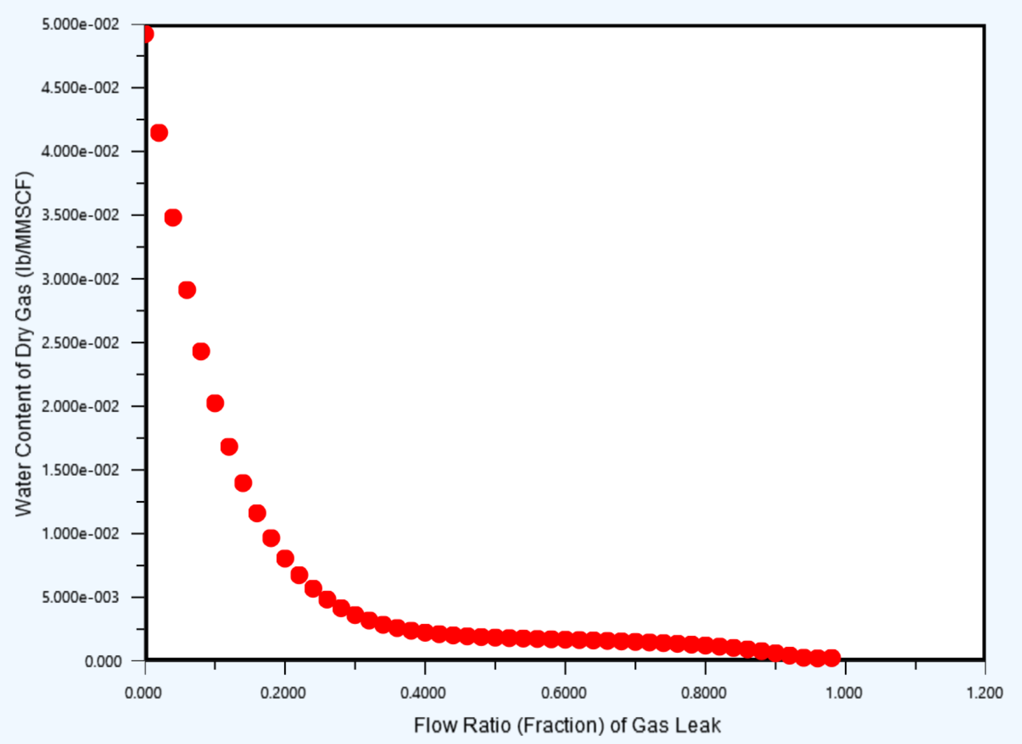

Fig. 14: Water content of dry gas and fraction of gas leak

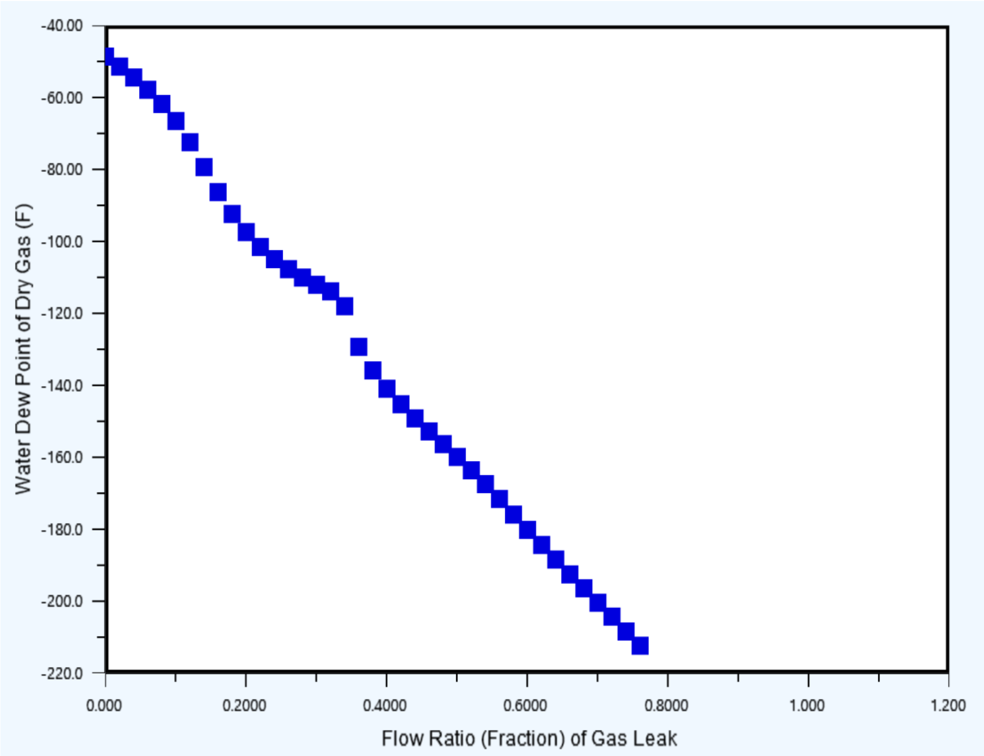

Fig. 15: Water Dewpoint of dry gas vs fraction of gas leak

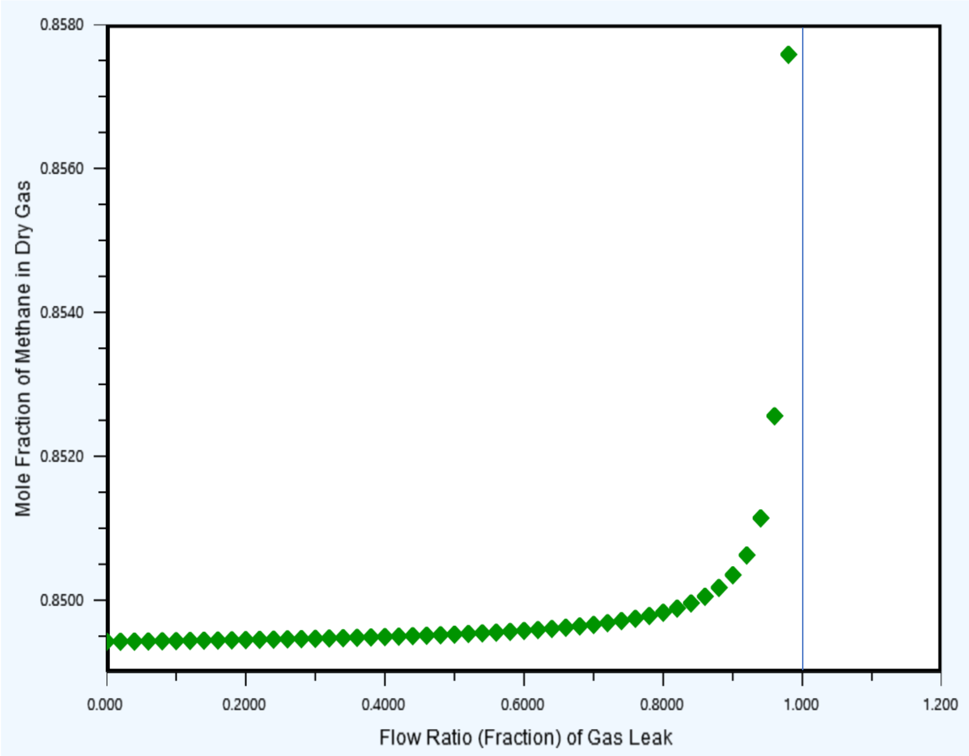

Fig. 16: Mole fraction of methane in dry gas vs fraction of gas leak

The result of the simulation with gas leak in the gas plant, showed that there exists a relationship between the volume of gas leaking out from the pipe and the water content; water dew point and mole fraction of methane in the "Dry Gas". To establish this fact, the simulation was done for different fraction of gas leak (i.e increasing the amount of gas leak and reducing the amount entering the inlet separator). In the dehydration column, the gas actually makes countercurrent contact with the TEG solvent. Therefore, reducing the amount of gas entering the dehydration column (with TEG flow rate unchanged), have some effect on the natural gas quality (water content; water dew point; and mole fraction of methane). Fig. 14, Fig. 15 and Fig. 16 show a plot of water content, water dew point and methane composition against fraction of gas leak of the total gas flow.

Fig. 14 showed that a decaying exponential relationship exists between the water content of the dry gas and the fraction of total gas leak in the gas plant. There are two extremes in the plots: 0.0 fraction of total gas leak and 1.0 fraction of total gas leak. Where the former may exist in a gas plant system (indicating no leak) the later may not exist, since all the gas cannot leak out from the system without some going into the separator, otherwise disaster of the highest magnitude is imminent. Above 0.8 fraction of total gas leaking out of the gas pipe, the water content approach 0 lb/MMScf, indicating that the gas is completely free of water vapour irrespective of the temperature and pressure of the gas. This type of system may not be possible in practice, because at 0.8 fraction of gas leaks (648 MMScfd out of 810 MMScfd leaking out with only 162 MMScfd entering the inlet separator), the gas plant would have gone up in flame, if emergency response is not put in place. This might be the reason for gas explosion in different gas plant in Nigeria.

Fig. 15 has a similar behaviour with Fig. 14, in a sense that as the fraction of gas leak increase, the water content and water dew point decrease, but the relationship between the water dew point and the fraction of total gas leak is inverse, indicating that increase in any of the parameter will cause decrease of the other parameter. The response of the gas plant during the leak with respect to methane composition, was also simulated and the result is shown in Fig. 16. The methane composition in the dry gas stream shows a small gradual increase as the fraction of gas leak increases up till 0.6. Above 0.6 fraction of gas leak, the increase in methane composition becomes obvious and with sharp increase between 0.9 and 1.0 fraction. The curve of Figure 15 showed an asymptote at 1.0 indicating that, it is practically impossible to have all the gas leak out from the gas pipeline without any going into the inlet separator and still expect the gas plant to be in operation.

4. Conclusion

In a natural gas processing system without any form of leak in any part of the system, the quality of the gas may remain unchanged or have very minor change due to process upset, such as pressure; temperature and flow rate disturbances. Where there is a leak in the natural gas system, the change in the quality of the processed gas becomes obvious as the volume of gas leaking out of the system increases, and this was the finding in this report. The simulation in this report found out that when there is a gradual or sudden increase in the quality of processed natural gas, the first parameter to check is the gas flow rate (amount of gas entering the dehydration column). If the outcome is affirmative, then there should be thorough search in the system for possible gas leak to avoid disaster that may damage process equipment, claim lives and damage the environment.

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