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Hydraulic, Modelling and Hydrate Inhibition for the New Gas Wellhead Flowlines in Gas Project-Part II

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Abstract

Natural gas is becoming one of the most widely used sources of energy in the world due to its environmentally friendly characteristics. In recent years, global natural gas consumption has grown rapidly, and the share of natural gas in primary energy consumption has reached a historical high level of 23.4%. This paper presents the steady state thermal hydraulic models in PIPESIM and transient model in OLGA at richest and leanest gas production for the gas wellhead flowlines 5,6,7 and 8 in the gas project to determine the suitable line sizes for these wellhead flowlines based on the normal production and turndown conditions. The velocity, erosion velocity limits , liquid hold up and other key thermal hydraulic variable for the gas wellhead flowlines of gas wells 5,6,7 and 8 were calculated.

The potential for hydrate formation on the gas wellhead flowlines for gas wells 5,6,7 and 8 was checked and the required dosage for the hydrate inhibitor was identified for each gas well. A comparison was carried out to benchmark the steady state pressure and temperature predictions obtained using dynamic 'OLGA' modelling against corresponding estimates obtained from the steady state 'PIPESIM' modelling. The results obtained from the two software are very close.

Keywords: *Wellhead flowline; OLGA; PIPESIM; FWHP; FWHT; GOR; Erosion velocity; CPF.*

1. Introduction

In the oil and gas industry, flowlines are pipelines that connect a single wellhead to the production manifold or the main process facilities in the CPF [1]. In a larger well field, multiple flowlines may connect individual wells to the production manifold. The gathering line may transfer the flow from the manifold to a pre-process stage or to a transportation facility or vessel [2]. Flowlines may be in a land or subsea and may be buried or at grade on the surface of land or seafloor. Trunklines are similar to the flowlines but collect the flow from multiple flowlines [3].

Flowlines are located at the well site tied to a specific well. It may be a metallic pipe or a hose. Most flowlines are very short in length but others may be run for kilometers in onshore applications [4]. The flowline is sized based on the maximum oil, gas and water flowrate from the well. In heavy oil applications, a flowline may be insulated to retain the heat of the formation in order to prevent plugging. If the line is too large, the velocity could be slow enough where separation might occur or particulate may settle out in the pipe, which causes corrosion issues [5-6].

Three-phase transient flows can be simulated with OLGA. Bendiksen *et al.* [7] first described OLGA features. OLGA is a two-fluid model which solves three separate continuity equations for gas, liquid bulk and liquid droplets, two momentum equations for gas together with possible liquid droplets and a separate one for liquid film at the wall, and at last one energy-conservation equation for the mixture of gas and liquid [8-10].

Ellul [11] summarized different approaches in multiphase flow modeling and compared the calculation results using an example. Steady-state and transient cases (ramp-up, scrapping) are studied

The purpose of this study is to build steady-state thermal-hydraulic models in PIPESIM and transient model in OLGA at richest gas and leanest gas production from gas wells 5,6,7 and 8 in the gas project to determine suitable line sizes for the wellhead flowlines of gas wells 5,6,7 and 8 based on the normal production and turndown conditions. Also calculate the velocity, liquid holdup and other key thermal hydraulic variables for all flowlines. Assess the potential for hydrate formation in flowlines and calculate the required dosage from the hydrate inhibitor for each gas well.

2. Methodology

2.1. Gas wells data

Eight producing wells are initially considered for the gas project. Figure 1 demonstrates the wells and the length for each wellhead flow line. A wellhead pressure of 267 bara, wellhead temperature of 50°C and the flowline pressure of 56 bar at the design flow rate of 0.425 MSCMD (15 MMSCFD) shall be used.

Design flow rate of each well: 0.425 MSCMD (15 MMSCFD).
Turn down flow – lean gas: 0.1 MSCMD (3.5 MMSCFD).
Turn down flow – rich gas: 0.21 MSCMD (7.5 MMSCFD).
Maximum Water cut of each well: 10 % of total liquids.

It is assumed that the all eight gas wells have the same design flowrate which is 0.425 MSCMD. A range of compositions of different condensate gas ratios (CGRs) can be delivered by each well depending on the layer being produced. The Richest and Leanest Gas Condensate Ratio from each well is presented in the Table 1.

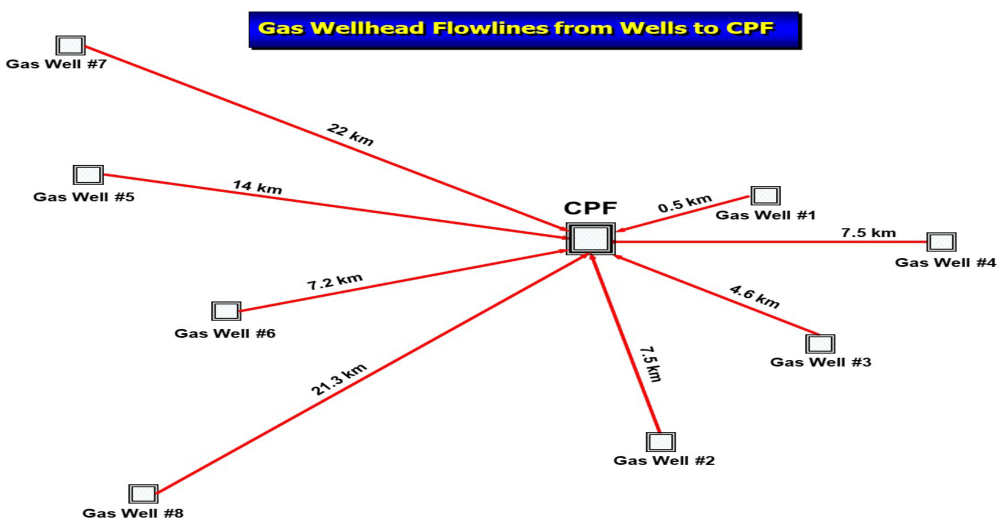

Figure 1. Gas wellhead flowlines from wells to CPF.

Table 1. Design production flowrates.

Well	Simulation Case	CGR SCM/MSCM	Gas Flowrate MSCMD	Condensate Flowrate SCMD	Water Flowrate SCMD
Gas well #5	Richest Case	362	0.425	154	51
	Leanest Case	256	0.425	109	36
	Sensitivity Case	1743	0.425	741	247
Gas well #6	Richest Case	790	0.425	336	112
	Leanest Case	148	0.425	63	21
Gas well #7	Richest Case	790	0.425	336	112
	Leanest Case	148	0.425	63	21
Gas well #8	Leanest Case	46	0.425	20	7
	Sensitivity Case	-	0.425	-	11
	Richest Case	71	0.425	30	10

2.2. Gas well fluid compositions

Fluid compositions are based on the latest zone compositions. Tables 2-5 illustrate the well composition from each gas well.

Table 2. Gas Well # 5 composition.

Component	Composition (Mol %)		
	Richest Case	Leanest Case	Rich (Sensitivity)
	Zone#1	Zone#2-tuned	Sample 214
N_2	0.42	0.42	0.24
CO_2	2.00	1.94	1.84
C_1	75.29	80.52	65.78
C_2	8.09	6.78	6.73
C_3	5.13	3.53	4.78
i-C_4	1.14	0.72	1.62
n-C_4	1.57	1.07	1.95
i-C_5	0.86	0.60	1.88
n-C_5	0.50	0.35	0.92
C_6	1.01	0.74	2.71
PS-1	1.77	1.57	5.24
PS-2	1.05	1.04	3.02
PS-3	0.71	0.57	1.97
PS-4	0.36	0.14	1.05
PS-5	0.10	0.00	0.27

Table 3. Gas Well # 6 composition.

Component	Composition (Mol %)	
	Richest Case	Leanest Case
	Zone#1	Zone#4-tuned
N_2	0.51	0.31
CO_2	1.72	1.94
C_1	73.07	85.76
C_2	6.70	5.12
C_3	4.57	2.40
i-C_4	0.92	0.47
n-C_4	1.75	0.78
i-C_5	0.95	0.40
n-C_5	0.72	0.28
C_6	1.56	0.55
PS-1	3.13	0.95
PS-2	1.98	0.53
PS-3	1.43	0.35
PS-4	0.73	0.15
PS-5	0.28	0.02

Table 4. Gas Well # 7 composition.

Component	Composition (Mol %)	
	Richest case	Leanest case
	Zone#1	Zone#4-tuned
N_2	0.51	0.31
CO_2	1.72	1.94
C_1	73.07	85.76
C_2	6.70	5.12
C_3	4.57	2.40
i-C_4	0.92	0.47
n-C_4	1.75	0.78
i-C_5	0.95	0.40
n-C_5	0.72	0.28
C_6	1.56	0.55
PS-1	3.13	0.95
PS-2	1.98	0.53
PS-3	1.43	0.35
PS-4	0.73	0.15
PS-5	0.28	0.02

Table 5. Gas Well # 8 composition.

Component	Composition (Mol %)		
	Richest case	Leanest case	Sensitivity case
	Zone#3	Zone#1	Zone#2
N_2	0.35	0.42	0.31
CO_2	2.09	2.20	2.30
C_1	87.88	87.73	91.96
C_2	5.10	5.44	3.47
C_3	1.98	1.96	1.00
i-C_4	0.31	0.40	0.17
n-C_4	0.50	0.42	0.22
i-C_5	0.25	0.27	0.12
n-C_5	0.17	0.14	0.08
C_6	0.33	0.29	0.14
PS-1	0.49	0.35	0.19
PS-2	0.26	0.16	0.03
PS-3	0.18	0.15	0.00
PS-4	0.10	0.07	0.00
PS-5	0.01	1.00E-06	0.00

2.3. Simulation basis

The composition reaching the CPF, however, will be a mixture of production from each well. There are 8 wells with different compositions in the gas project. Erosion velocity checks to be based on API RP 14E [12]. The steady state pipeline simulator, PIPESIM 2017 [13] was used for the modelling wellhead flowlines of the gas project for the base case (rich and lean) and turndown cases, the results obtained from PIPESIM 2017. OLGA 2017 [14] was used for transient modelling of the wellhead flowlines of the gas project.

A comparison was made between the results obtained from PIPESIM 2017 and OLGA 2017 as illustrated in the results and discussions. Compositional method based upon Peng Robinson equation of state is to be used to characterize the gas/condensate fluid. OLGA 2017 multiphase flow correlation is to be used for multiphase flow simulation. The fluid files used for the OLGA simulations were generated using PVTSIM with the Peng Robinson Equation of state used to create the fluid properties using the relevant fluid composition and pseudo properties.

PIPESIM 2017 was used to get the blended compositions from the lean and reach layer for each well. The mix of the production from each well shall be selected so as not to exceed the liquid handling capacity of the CPF, i.e., 10000 SBPD of condensate product whilst maintaining a maximum production of 2.7 MSCMD export gas.

2.3.1. Simulation cases

To cover all possible flow situations in the lines, 6 simulation cases were initially run for each flowline using PIPESIM 2017. These cases are described below and summarized in Table 11. Table 6 depicts the simulation cases conducted by PIPESIM and OLGA simulation software.

Table 6. Simulation cases for gas wellhead flowlines.

Case No.	Description	CPF arrival pressure (bara)	Wellhead temperature (ºC)	Flowrate per well (MSCMD)	Composition
1	Base Case-Rich Gas	50-60	50	0.425	Rich
2	Base Case-Lean Gas	50-60	50	0.425	Lean
3	Turndown Case 1	50-60	24	0.10	Lean
4	Turndown Case 2	50-60	43	0.213	Rich
5	Depletion Case 1	25	20	0.14	Lean
6	Depletion Case 2	10	20	0.14	Lean

3. Results and discussions

3.1. Steady state results

PIPESIM 2107 was used to simulate the wellhead flowlines of the gas project.

3.1.1. Gas well # 5

Table 7 reveals the results obtained from PIPESIM simulation program for gas well #5 at different compositions.

3.1.1.1. Base case

The richest production from gas well#5 is rich gas condensate (CGR 790 SCM/MSCM) and the leanest production is lean gas condensate (CGR 148 SCM/MSCM). (The richest and leanest gas productions from this well are referred to as rich gas and lean gas cases.) Based on the 6″ flowline and rich case, maximum mixture velocity in the line is 4.7 m/s with maximum EVR of 0.41. Hence, 6″ flowline is considered as feasible line size.

Based on 6″ flowline and lean case, temperature drop across the choke is 30 ºC and pipeline inlet temperature is 31ºC which drops to 19ºC at flowline outlet. This is however marginally outside the hydrate formation temperature of 18ºC. Therefore, hydrate inhibitor may still be required for base case. Flow regime in the 6″ line for rich gas production is predominantly stratified wavy/slug. Flow regime in the 6″ line for lean gas production is predominantly stratified wavy and no slugging is predicted in steady-state production of lean gas.

3.1.1.2. Depletion case

For depletion case, the minimum temperature in the line is 15ºC, which is above hydrate formation temperature. Hence, there is no risk of hydrate formation in the line for the depletion case.

3.1.1.3. Turndown case

For turndown production flowrate of 0.1 MSCMD of lean gas, temperature drops to -15ºC downstream the choke valve and increases to 15ºC at flowline outlet. Hence, there is the risk of hydrate formation in the line. Note: hydrate inhibition and/or wellhead heating will be required for the low flowing temperature cases. The maximum predicted methanol inhibitor rate required is 5.1 SCMD (turndown 1 case).

For turndown production flowrate of 0.21 MSCMD of rich case, liquid holdup volume % in the line is in the range of 2 to 46 % and total liquid holdup volume is 52 m3. With turndown flow and depletion case, slug flow is predicted in the line. The highest predicted liquid holdup in the system is in turndown case 1, equal to 59 m3, where slug flow is predicted in most sections of the flowline and liquid holdup volume % varies between 10 to 35 %.

Figure 2 illustrate the temperature profile for the gas well #5 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #5 while figure 3 shows the pressure profile for the gas well #5 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #5. It can be noticed that the temperature and the pressure are changing across the wellhead flowline of gas well #5 because the total length of the wellhead flowline of gas well#5 is long (14 km) and the elevation of the line is 60 meter between the highest and lowest point.

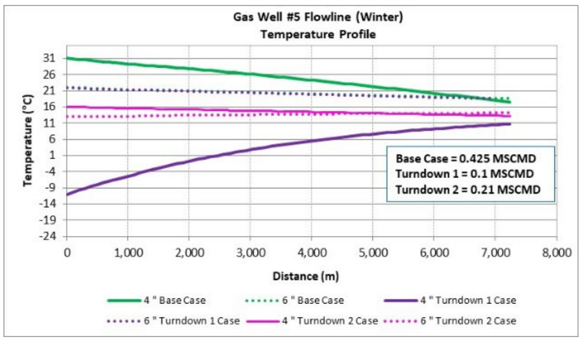

Figure 2. Gas well #5 flowline temperature profile in winter.

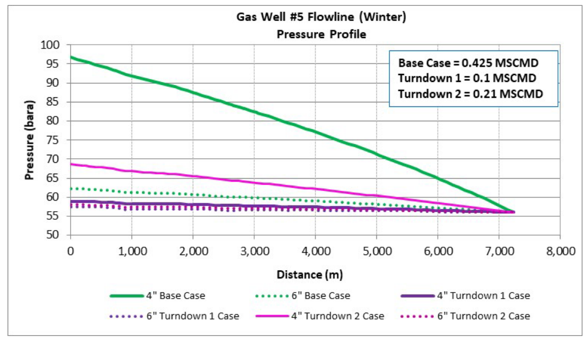

Figure 3. Gas well #5 flowline pressure profile in winter.

3.1.2. Gas Well # 6

Table 8 reveals the results obtained from PIPESIM simulation program for gas Well #6 at different compositions.

3.1.2.1. Base case

The richest and leanest productions from gas well #6 are medium lean gas condensates with CGR 362 SCM/MSCM and CGR 256 SCM/MSCM. (The richest and leanest gas productions from this well are referred to as rich gas and lean gas cases.) According to the reservoir fluid sampling results for gas well #5, sample MSPR-214 shows rich gas production with CGR 1,743 SCM/MSCM from the well. Current study uses this sample as a sensitivity case.

There are two different routes for gas well #6 flowline. The longer route (7,234 m) is used as the basis for this study and the shorter route (5,819 m) has been considered as a sensitivity case. Based on the 4″ flowline and rich case, maximum mixture velocity in the line is 9.7 m/s with maximum EVR of 0.8. For sensitivity case of rich gas production from the well (PVT sample MSPR-214), maximum fluid velocity in the line is 10.5 m/s with EVR of 1.1. Hence, 4″ flowline is not considered as feasible line size. Based on 6″ flowline (5.8″ ID) and rich case, maximum fluid velocity is 4.5 m/s with maximum EVR of 0.34.

Based on 6″ flowline and lean case, temperature drop across the choke is 32ºC and flowline inlet temperature is 18ºC, which is below hydrate formation temperature of 21ºC; hydrates will form, and hydrate inhibitor injection is required for base case. The maximum predicted methanol inhibitor rate required is 8.0 SCMD. Flow regime in the 6″ line and base case, Rich Gas is predominantly stratified-wavy /slug. Flow regime in the 6″ line and base case, lean gas is predominantly stratified-wavy, and no slugging is predicted anywhere in the flowline during steady-state production of lean gas.

3.1.2.2 Depletion case

For depletion case, the minimum temperature in the line is 14ºC, which is below hydrate formation temperature of 13ºC. Hence, there is risk of hydrate formation in the line and hydrate inhibitor injection will be required. The maximum predicted methanol inhibitor rate required is 0.4 SCMD.

3.1.2.3. Turndown case

For turndown production flowrate of 0.1 MSCMD of lean gas, temperature drops to -11ºC downstream of the choke valve. Hence, there is the risk of hydrate formation in the line. Note: hydrate inhibition and/or wellhead heating will be required for the low flowing temperature cases. The maximum predicted methanol inhibitor rate required is 7.9 SCMD (turndown1 case). For turndown production flowrate of 0.21 MSCMD of rich case, liquid holdup volume % in the line is in the range of 8 to 32 % and total holdup volume is 21 m^3. With turndown flow and depletion case, flow regime is predicted to be stratified-wavy/slug.

The highest predicted liquid holdup in the system is in turndown case 1, equal to 28 m^3, where slug flow is predicted in most sections of the flowline and liquid holdup % varies between 4 to 48 %. Figure 4 illustrate the temperature profile for the gas well #6 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #6 while Figure 5 shows the pressure profile for the gas well #6 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #6. It can be noticed that the temperature and the pressure are changing across the wellhead flowline of gas well #6 because the total length of the wellhead flowline of gas well#6 is long (7.2 km) and the elevation of the line is 38 meters between the highest and lowest point.

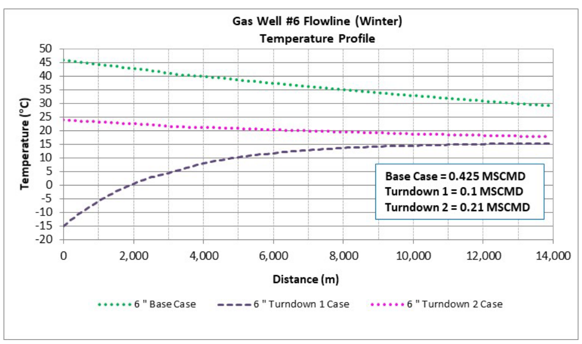

Figure 4. Gas well #6 flowline temperature profile in winter.

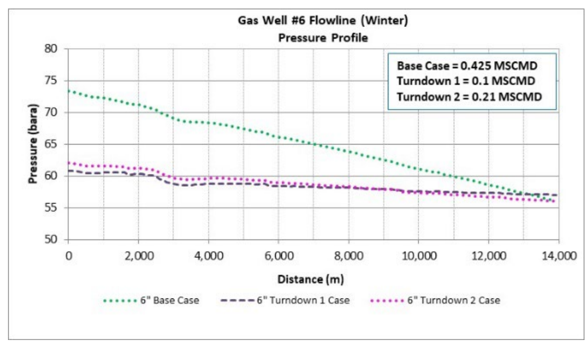

Figure 5. Gas well #6 flowline pressure profile in winter.

3.1.3. Gas well # 7

Table 9 shows the results obtained from PIPESIM simulation program for gas well #7 at different compositions.

3.1.3.1. Base case

The richest production from gas well #7 is rich gas condensate (CGR 790 SCM/MSCM) and the leanest production is lean gas condensate (CGR 148 SCM/MSCM). (The richest and leanest gas productions from this well are referred to as Rich Gas and Lean Gas cases.) Based on the 6” flowline and rich case, maximum mixture velocity in the line is 4.6 m/s with maximum EVR of 0.4. Hence, 6” pipeline is considered as feasible line size.

Based on 6” flowline and base case production, minimum temperature in the line is 16 ºC which is less than hydrate formation temperature of 17 ºC and therefore hydrate inhibitor injection will be required for base case. The maximum predicted methanol inhibitor rate required is 0.7 SCMD.

Flow regime in the 6” line for base case, lean gas is predominantly stratified-wavy, and no slug flow is predicted anywhere in the flowline. Intermittent slugging is predicted for base case, rich gas.

3.1.3.2. Depletion case

For depletion case, the minimum temperature in the line is 15ºC, which is above hydrate formation temperature of 5ºC. Hence, there is no risk of hydrate formation in the line for the depletion case.

3.1.3.3. Turndown case

For turndown production flowrate of 0.1 MSCMD of lean gas, temperature drops to -15ºC downstream the choke valve and increases to 16ºC at flowline outlet. Hence, there is the risk of hydrate formation in the line during turndown conditions. Note: hydrate inhibition and/or wellhead heating will be required for the low flowing temperature cases.

The maximum predicted methanol inhibitor rate required is 9 SCMD (turndown 2 case).

For turndown production flowrate of 0.21 MSCMD of rich case, liquid holdup volume % in the line is in the range of 9 to 37 % and total liquid holdup volume is 95.8 m^3. This case also represents the highest predicted holdup volume in the system. With base case (rich gas), turndown flow and depletion case, slug flow is predicted in the line.

Figure 6 reveals the temperature profile for the gas well #7 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #6 while Figure 7 displays the pressure profile for the gas well #7 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #7. It can be noticed that the temperature and the pressure are changing across the wellhead flowline of gas well #7 because the total length of the wellhead flowline of gas well#7 is too long (22 km) and the elevation of the line is 60 meter between the highest and lowest point.

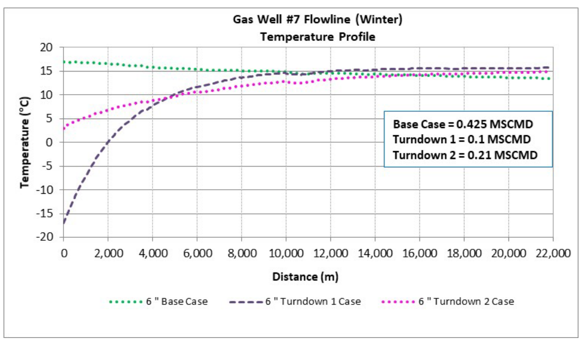

Figure 6. Gas well #7 flowline temperature profile in winter.

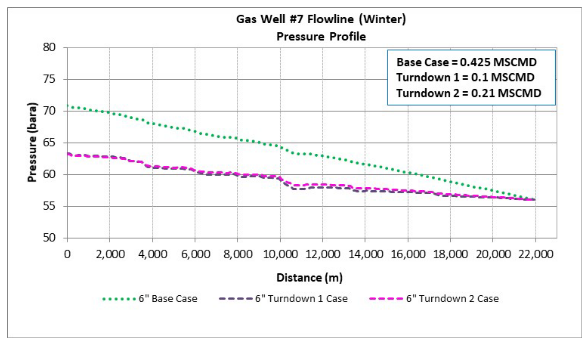

Figure 7. Gas well #7 flowline pressure profile in winter.

3.1.4. Gas well # 8

Table 10 displays the results obtained from PIPESIM simulation program for gas well #8 at different compositions.

3.1.4.1. Base case

The richest and leanest productions from gas well #8 are lean gas condensates with CGR 71 SCM/MSCM and 46 SCM/MSCM (The richest and leanest gas productions from this well are referred to as rich gas and lean gas cases.) Dry gas is also been produced from zone#2 which is considered in this study as a sensitivity case.

Based on the 6" flowline and rich case, maximum mixture velocity in the line is 4.6 m/s with maximum EVR of 0.3. Hence, 6" flowline is considered as feasible line size. Based on 6" flowline and base case production, minimum temperature in the line is 8ºC which is less than hydrate formation temperature of 18ºC and therefore there is the risk of hydrate formation during normal production and hydrate inhibitor injection will be required.

The maximum predicted methanol inhibitor rate required is 5.1 SCMD. This is based on the Dry Gas composition (25% water cut at flowing conditions).Based on 6" flowline and Dry Gas production (sensitivity case), temperature drop across the choke valve is 47ºC and minimum temperature in the line is 3ºC. Therefore, there is the risk of hydrate formation during normal production and hydrate inhibitor injection will be required. Flow regime in the 6" line for base case, rich gas and lean gas is predominantly stratified-wavy and no slug flow is predicted.

3.1.4.2. Depletion case

For depletion case, the minimum temperature in the line is 15ºC, which is above hydrate formation temperature of 8ºC. Hence, there is no risk of hydrate formation in the line.

3.1.4.3. Turndown case

For turndown production flowrate of 0.1 MSCMD of lean gas, temperature drops to -23ºC downstream the choke valve and increases to 16ºC at flowline outlet. Hence, there is the risk of hydrate formation in the line during turndown conditions. Note: hydrate inhibition and/or wellhead heating will be required for the low flowing temperature cases. The maximum predicted methanol inhibitor rate required is 3.2 SCMD (turndown 2 case).

For turndown production flowrate of 0.21 MSCMD of rich case, liquid holdup volume % in the line is in the range of 2 to 31 % and total liquid holdup volume is 32 m^3. With turndown flow and depletion case, slug flow is predicted in the line. The highest predicted liquid holdup volume in the system is in turndown case 1, equal to 71 m^3, where slug flow is predicted in most sections of the pipeline and liquid holdup % varies between 1 to 59 %.

Figure 8 displays the temperature profile for the gas well #8 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #6 while Figure 9 illustrate the pressure profile for the gas well #8 wellhead flowline in winter case at different wellhead flowline sizes and different gas compositions from gas well #8. It can be noticed that the temperature and the pressure are changing across the wellhead flowline of gas well #8 because the total length of the wellhead flowline of gas well#8 is long (21.3 km) and the elevation of the line is 40 meters between the highest and lowest point.

Table 10. Steady state hydraulic results for gas well #8 flowline.

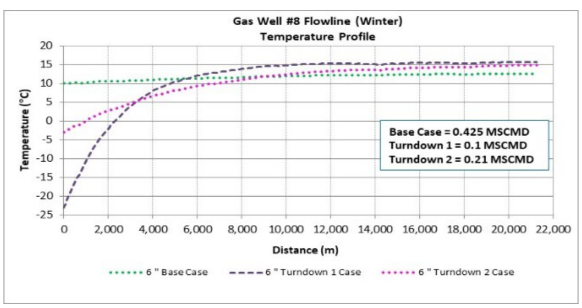

Figure 8. Gas well #8 flowline temperature profile in winter.

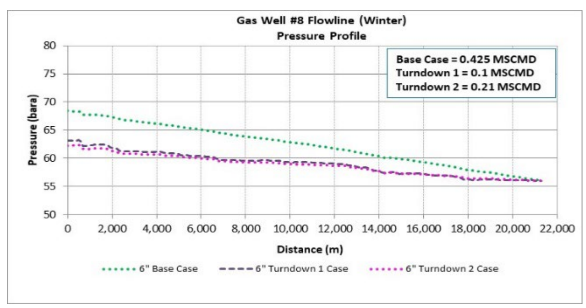

Figure 9. Gas well #8 flowline pressure profile in winter.

3.2. Summary of OLGA software results

Table 11 displays the transient hydraulic results when OLGA software was used to simulate the new gas wellhead flowlines for the gas project. Tables 12, 13 illustrate the comparison between the results obtained from PIPESIM software and OLGA software at different conditions. A comparison was first carried out to benchmark the steady state pressure and temperature predictions obtained using dynamic 'OLGA' modelling against corresponding estimates obtained from the steady state 'PIPESIM' modelling.

This benchmarking exercise was performed for the 6" line size operating at base and turndown 1 case conditions. From the comparison table between the results of PIPESIM software and OLGA software, it can be noticed that the results obtained from the two software are very close.

4. Conclusions & recommendations

For gas well # 5, gas well # 6, gas well# 7 and gas well #8 flowlines, 6" pipelines (ID=5.8") are considered feasible. For gas well #2, gas well #3 and gas well #4, 4" and 6" line sizes are feasible. Erosional velocity checks in accordance with API RP 14E using a C-factor of 100 indicate that EVR is less than 1.0 for all cases; hence, there is no risk of erosion in the flowlines. The impact of heating the flowing temperature for each flowline was investigated to mitigate against hydrate formation in the flowline at low flowing temperatures. The results show that for the gas well # 1 flowline, a flowing temperature of 25 ºC is enough to ensure that the flowline operates outside the hydrate region. For all other flowlines, the maximum flowing temperature of 60ºC will not be adequate in ensuring that the flowlines operate completely outside the hydrate region. The effect of mixing well fluids in varying ratios of richest fluid/leanest fluid has no significant impact on hydrate formation conditions in the flowlines. The following table summarizes the concussions for each well

Well Name	Minimum operating on flowline Temperature, ºC	Hydrate formation temperature, ºC	Hydrate inhibitor requirements	Maximum methanol inhibitor rate, SCMD	Type of flow regime	Slug flow regime formation
Gas Well #5	-11	20	Required	7.8 in turndown case	Stratified-Wavy	Slug flow regime is predicted in some sections of the line during depletion, turndown and normal production of rich gas and turndown case for lean gas.
Gas Well #6	-15	20	Required	5.1 in turndown case	Stratified-Wavy	Slug flow regime is predicted in some sections of the line during depletion, turndown and normal production of rich gas and turndown case for lean gas.
Gas Well #7	-15	20	Required	9 in turndown case	Stratified-Wavy	Slug flow regime is predicted in some sections of the line during normal and turndown production of rich gas, depletion, and turndown case for lean gas.
Gas Well #8	-23	18	Required	5.1 at 25% water cut	Stratified-Wavy	Slug flow regime is predicted in some sections of the line during depletion and turndown production of rich gas and turndown case for lean gas.

Nomenclature

API RP	*American Petroleum Institute Recommended Practice*
bpd	*Barrels per day*
CGR	*Condensate gas ratio*
CPF	*Central processing facility*
DP	*Pressure drop*
EVR	*Erosional velocity ratio*
FWHP	*Flowing well head pressure*
FWHT	*Flowing well head temperature*
GOR	*Gas-oil ratio*
HP	*High pressure*
ID	*Internal diameter*
LDHI	*Low dosage hydrate inhibitors*
LP	*Low pressure*
MP	*Medium pressure*
MMSCFD	*Million standard cubic feet per day*
MSCMD	*Million standard cubic meter per day*
NB	*Nominal bore*
LPG	*Liquefied petroleum gas*
MSCD	*Standard cubic meter per day*
W.C	*Water cut*
WHP	*Wellhead pressure*
WHT	*Wellhead temperature*

Table 7. Steady state hydraulic results for gas well #5 flowline.

Hydrate Temp (Inlet), ºC	Hydrate Temp (Outlet), ºC	Summer / Winter	Case	Fluid	CGR, SCM / MSCM	Condensate, SCMD	Water, SCMD	Methanol, SCMD	Gas Flowrate, MSCMD	Size, in	Temp In, ºC	Temp Out, ºC	Press In, bara	Press Out, (CPF), bara	Mix. Velocity at Outlet, m/s	Max. EVR	Potential Hydrate	Flow Regime	Total Liquid Holdup , m^3
20	18	S	Base Case	Rich	790	335.8	111.9	0.0	0.425	6	46	35	74	56	4.7	0.41	No	S Wavy	49.8
20	18	W	Base Case	Rich	790	335.8	111.9	0.0	0.425	6	46	29	73	56	3.7	0.36	No	Slug/S Wavy	50.7
18	17	W	Base Case	Lean	148	62.9	21	0.0	0.425	6	31	19	66	56	4.4	0.29	No	S Wavy	18.7
12	12	W	Depletion-25	Lean	148	20.7	6.9	0.0	0.14	6	20	16	27	26	3.3	0.15	No	Slug/S Wavy	16.1
8	5	W	Depletion-10	Lean	148	20.7	6.9	0.0	0.14	6	20	15	17	11	8.2	0.23	No	Slug/S Wavy	8.9
18	17	W	Turndown1	Lean	148	14.8	4.9	5.1	0.10	6	-15	15	61	56	1.0	0.07	Yes	Slug/S Wavy	52.0
19	18	W	Turndown2	Rich	790	167.9	56	1.6	0.21	6	24	18	62	56	2.1	0.2	Yes	Slug/S Wavy	58.6

Table 8. Steady-state hydraulic results for gas well 6 flowline.

Hydrate Temp (Inlet), ºC	Hydrate Temp (Outlet), ºC	Summer / Winter	Case	Fluid	CGR, SCM / MSCM	Condensate, SCMD	Water, SCMD	Methanol, SCMD	Gas Flowrate, MSCMD	Size, in	Temp In, ºC	Temp Out, ºC	Press In, bara	Press Out (CPF), bara	Mix. Velocity at Outlet, m/s	Max. EVR	Potential Hydrate	Flow Regime	Total Liquid Holdup, m3
22	19	S	Base Case	Rich	362	153.9	51.3	0.0	0.425	4	31	21	97	56	9.7	0.8	No	S Wavy	6.7
20	19	S	Base Case	Rich	362	153.9	51.3	0.0	0.425	6	22	22	62	56	4.5	0.34	No	S Wavy	18.1
22	19	W	Base Case	Rich	362	153.9	51.3	3.2	0.425	4	31	17	97	56	9.5	0.76	Yes	S Wavy	6.9
20	19	W	Base Case	Rich	362	153.9	51.3	0.1	0.425	6	22	19	62	56	4.1	0.30	Yes	Slug/S Wavy	18.4
23	17	W	Richer (Sensitivity)		1743	740.8	246.9	0.0	0.425	4	46	34	130	56	10.5	1.10	No	Slug/S Wavy	16.9
19	17	W	Richer (Sensitivity)		1744	741.2	247.1	0.0	0.425	6	39	33	68	56	4.5	0.46	No	Slug/S Wavy	35.0
21	19	W	Base Case	Lean	256	108.8	36.3	8.0	0.425	4	27	14	93	56	9.7	0.70	Yes	S Wavy	5.2
19	19	W	Base Case	Lean	256	108.8	36.3	3.2	0.425	6	18	16	62	56	4.2	0.30	Yes	S Wavy	14.3
15	13	W	Depletion-25	Lean	256	35.8	11.9	0.4	0.14	4	20	14	37	26	7.6	0.36	Yes	S Wavy	3.9
13	13	W	Depletion-25	Lean	256	35.8	11.9	0.0	0.14	6	20	17	28	26	3.3	0.16	No	Slug/S Wavy	10.0
13	6	W	Depletion-10	Lean	256	35.8	11.9	0.0	0.14	4	20	11	29	11	18.7	0.57	No	S Wavy	3.0
8	6	W	Depletion-10	Lean	256	35.8	11.9	0.0	0.14	6	20	16	14	11	8.2	0.25	No	Slug/S Wavy	6.0
19	19	W	Turndown1	Lean	256	25.6	8.5	7.9	0.1	4	-11	11	59	56	2.2	0.17	Yes	Slug/S Wavy	8.1
18	19	W	Turndown1	Lean	256	25.6	8.5	7.8	0.1	6	-11	12	57	56	1.0	0.07	Yes	Slug/S Wavy	28.0
20	19	W	Turndown2	Rich	362	76.9	25.6	5.8	0.21	4	16	13	69	56	4.6	0.38	Yes	S Wavy/slug	8.3
19	19	W	Turndown2	Rich	362	76.9	25.6	4.8	0.21	6	13	14	58	56	2.0	0.16	Yes	S Wavy/slug	20.9

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Table 9. Steady state hydraulic results for gas well #7 flowline

Hydrate Temp (Inlet), ºC	Hydrate Temp (Outlet), ºC	Summer / Winter	Case	Fluid	CGR, SCM / MSCM	Condensate, SCMD	Water, SCMD	Methanol, SCMD	Gas Flowrate, MSCMD	Size, in	Temp In, ºC	Temp Out, ºC	Press In, bara	Press Out (CPF), bara	Mix. Velocity at Outlet, m/s	Max. EVR	Potential Hydrate	Flow Regime	Total Liquid Holdup , m^3
20	18	S	Base Case	Rich	790	335.8	111.9	0	0.425	6	46	31	82.2	56	4.6	0.40	No	Slug/S Wavy	83.6
20	18	W	Base Case	Rich	790	335.8	111.9	0.0	0.425	6	46	24	81.8	56	4.4	0.40	No	Slug/S Wavy	85.5
18	17	W	Base Case	Lean	148	62.9	21.0	0.7	0.425	6	31	16	70.8	56	4.3	0.30	Yes	S Wavy	31.1
12	12	W	Depletion-25	Lean	148	20.7	6.9	0.0	0.14	6	20	16	31.9	26	3.3	0.15	No	Slug/S Wavy	27.0
8	5	W	Depletion-10	Lean	148	20.7	6.9	0.0	0.14	6	20	15	19.6	11	8.3	0.23	No	Slug/S Wavy	15.6
18	17	W	Turndown1	Lean	148	14.8	4.9	5.0	0.10	6	-15	16	62.9	56	1.0	0.10	Yes	Slug/S Wavy	84.3
19	18	W	Turndown2	Rich	790	167.9	56.0	9.0	0.21	6	24	13	66.0	56	2.1	0.20	Yes	Slug/S Wavy	95.8

Table 10. Steady state hydraulic results for gas well #8 flowline.

Hydrate Temp (Inlet), ºC	Hydrate Temp (Outlet), ºC	Summer / Winter	Case	Fluid	CGR, SCM / MSCM	Condensate, SCMD	Water, SCMD	Methanol, SCMD	Gas Flowrate, MSCMD	Size, in	Temp In, ºC	Temp Out, ºC	Press In, bara	Press Out (CPF), bara	Mix. Velocity at Outlet, m/s	Max. EVR	Potential Hydrate	Flow Regime	Total Liquid Holdup, m^3
18	17	S	Base Case	Rich	71	30.2	10.1	2.2	0.425	6	11	23	68.0	56	4.6	0.28	Yes	S Wavy	18.4
18	17	W	Base Case	Rich	71	30.2	10.1	2.6	0.425	6	10	13	68.0	56	4.3	0.27	Yes	S Wavy	20.0
18	17	W	Base Case	Dry Gas *	-	-	10.9	5.1	0.425	6	3	13	66.0	56	4.3	0.26	Yes	S Wavy	3.1
18	17	W	Base Case	Lean	46	19.6	6.5	2.0	0.425	6	8	13	67.5	56	4.3	0.27	Yes	S Wavy	15.0
13	11	W	Depletion-25	Rich	46	6.4	2.1	0.0	0.14	6	20	16	32.0	26	3.4	0.14	No	Slug/S Wavy	20.4
8	4	W	Depletion-10	Rich	46	6.4	2.1	0.0	0.14	6	20	15	18.0	11	8.3	0.20	No	Slug/S Wavy	9.6
18	17	W	Turndown1	Lean	46	4.6	1.5	2.0	0.10	6	-23	16	63.0	56	1.0	0.06	Yes	Slug/S Wavy	71.0
17	17	W	Turndown2	Rich	71	15.1	5	3.2	0.21	6	-3	15	62.0	56	2.2	0.14	Yes	Slug/S Wavy	31.8

*(25% water cut at flowing conditions)

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Table 11. Transient Hydraulic Results by OLGA software for all Gas Wellhead Flowlines

Well	Simu. Case	Comp.	Wellhead Temp., ºC	Wellhead Pressure, bara	Inlet to Flowline Temp., ºC	Inlet to Flowline Pressure (Pipesim), bara	Arrival at CPF Temp. (Pipesim.), ºC	Hydrate Form. Temp at Inlet P, ºC	Temp. Depression required based on Pipesim, ºC	Arrival at CPF Temp. (OLGA Simu. With Amb. Soil	MeOH Rate based on OLGA with Amb Soil (with
Gas Well#5	Base	Rich	50	267	22	62.5	18.5	17.7	3.2	17.4	5.5
	Base	Lean	50	267	18	61.8	15.8	16.8	5.0	15.6	5.3
	Base	Rich	50	267	22	62.4	13.1	17.7	8.6	9.4	17.8
	Base	Lean	50	267	18	61.7	9.9	16.8	10.9	6.6	15.8
	Base	Rich	50	267	22	62.4	14.9	17.7	6.8	12.1	13.4
	Base	Lean	50	267	18	61.7	11.9	16.8	8.9	9.6	12.2
	Base	Rich	50	267	22	62.5	16.4	17.7	5.3	14.2	10.3
	Base	Lean	50	267	18	61.7	13.6	16.8	7.2	12	9.4
Gas Well#6	Base	Rich	61	228	46	73.9	29.1	17.9	0.0	23.2	0.0
	Base	Lean	61	228	31	66	18.8	16.6	1.8	16.2	2.1
	Base	Rich	61	228	46	73.6	21.3	17.9	0.6	12.7	23.0
	Base	Lean	61	228	31	65.7	8.1	16.5	12.4	3.1	12.5
	Base	Rich	61	228	46	73.7	23.9	17.9	0.0	16.2	11.3
	Base	Lean	61	228	31	65.8	11.7	16.5	8.8	7.4	8.5
	Base	Rich	61	228	46	73.7	26	17.9	0.0	19	2.6
	Base	Lean	61	228	31	65.9	14.6	16.5	5.9	11	5.8
Gas Well#7	Base	Rich	61	228	46	82.5	23.6	18.6	0.0	18.5	8.4
	Base	Lean	61	228	31	70.5	16.1	17	4.9	14.9	3.4
	Base	Rich	61	228	46	81.9	13.5	18.5	9.0	6	48.0
	Base	Lean	61	228	31	70.7	3.4	17	17.6	0.5	15.1
	Base	Rich	61	228	46	82.1	16.9	18.6	5.7	10.1	34.1
	Base	Lean	61	228	31	70.9	7.7	17	13.3	5.3	10.8
	Base	Rich	61	228	46	82.2	19.6	18.6	3.0	13.5	22.8
	Base	Lean	61	228	31	71	11.1	17	9.9	9.2	7.7
Gas Well#8	Base	Rich	50	267	11	67.8	12.9	16.3	7.4	14.4	2.4
	Base	Lean	50	267	8	67.7	12.5	16.4	7.9	14.3	2.0
	Base	Rich	50	267	11	67.4	0.1	16.3	20.2	0.4	9.5
	Base	Lean	50	267	8	67.3	-0.4	16.4	20.8	0.2	7.4
	Base	Rich	50	267	11	67.5	4.4	16.3	15.9	5	6.7
	Base	Lean	50	267	8	67.4	3.9	16.4	16.5	4.9	5.3
	Base	Rich	50	267	11	67.7	7.8	16.3	12.5	8.8	4.9
	Base	Lean	50	267	8	67.5	7.3	16.4	13.1	8.6	4.1

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Table 12. OLGA Software vs PIPESIM Software Benchmarking Results (Base Case, 10 % W.C).

Flowline	Length	Case	Gas	Gas Flowrate	size	Temp, in	Temp, out	Press, in	Press, out (CPF)	Mix. Velocity at outlet	Max. EVR	Total Liquid Holdup Volume	Flow Regime
	m			MMSCMD	in	ºC	ºC	bara	bara	m/s	-	m³	
Gas Well#5	14,000	Base Case	Rich	0.425	6	22	19.0	62.0	56	4.1	0.30	18.4	Slug/S Wavy
		Base Case	Rich	0.425	6	22	17.0	61.6	56	4.4	0.31	16.4	Int. Slug
Gas Well#6	7,200	Base Case	Rich	0.425	6	46	29.0	73.0	56	3.7	0.36	50.7	Slug/S Wavy
		Base Case	Rich	0.425	6	46	18.8	67.3	56	4.5	0.31	30.7	Strat.
Gas Well#7	22,000	Base Case	Rich	0.425	6	46	23.7	81.8	56	4.4	0.39	85.5	Slug/S Wavy
		Base Case	Rich	0.425	6	46	16.4	77.1	56	4.6	0.36	76.8	Int. Slug
Gas Well#8	21,300	Base Case	Rich	0.425	6	10	13.0	68.0	56	4.3	0.27	20.0	S Wavy
		Base Case	Rich	0.425	6	10	14.7	67.5	56	4.5	0.27	15.6	Strat.

Table 13. OLGA Software vs PIPESIM Software Benchmarking Results (Turndown case, 10 % W.C).

Flowline	Length	Case	Gas	Gas Flowrate	size	Temp, in	Temp, out	Press, in	Press, out (CPF)	Mix. Velocity at outlet
	m			MSCMD	in	ºC	ºC	bara	bara	m/s
Gas Well#5	14,000	Turndown1	Lean	0.100	6	-11	12.3	57.0	56	1.0
		Turndown1	Lean	0.100	6	-11	15.7	57.2	56	1.1
Gas Well#6	7,200	Turndown1	Lean	0.100	6	-15	15.0	61.0	56	1.0
		Turndown1	Lean	0.100	6	-15	15.9	59.3	56	1.1
Gas Well#7	22,000	Turndown1	Lean	0.100	6	-15	15.7	62.9	56	1.0
		Turndown1	Lean	0.100	6	-15	15.9	62.0	56	1.2
Gas Well#8	21,300	Turndown1	Lean	0.100	6	-23	16.0	63.0	56	1.0
		Turndown1	Lean	0.100	6	-23	16.0	61.4	56	1.1

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