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An Integrated Production Optimization Approach of a Natural Gas Filed in Bangladesh

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Abstract:

This paper presents an integrated production model for a producing gas field in Bangladesh. Integrated production modeling is a powerful method for optimizing gas or oil field production planning. This approach combines the reservoir performance, well inflow and outflow relationship and the surface facilities in a single platform to cover all operating envelopes and constrains. Once the model is established and validated, the production forecasts can be generated to study alternative development scenarios against reservoir performances. This allows choosing an optimum production strategy from different options. The method is computationally intensive, therefore commercial software packages are used to conduct this study. PROSPER™, MBAL™ and GAP™ modules from the IPM software suite were used to carry out this work. The current production strategies predict recovery factor of 49.38 % and 40.46% from Upper Gas Sand (UGS) and Lower Gas Sand (LGS) respectively, for next 25 years. An attempt to increase production from this field was considered in this study, since the field is producing only 50 MMCFD while the installed process plant capacity of 220 MMCFD. Several production strategies have been investigated that includes change in the tubing size of existing well, setting up new wells and addition of compressor facilities. Plateau production and ultimate recovery for next 25 years were compared for these scenarios. Initially change in the tubing sizes has been studied for well # 1 in UGS and well # 3, 4 in LGS gives 16% and 3% increase in ultimate recovery from current tubing condition respectively. The effect of adding two infill wells in UGS and two in LGS has also been studied. With additional wells, the ultimate recovery factor increases to 68.5% and 57 % for UGS and LGS respectively. Using compressor and infill wells shows the recovery of 92% for UGS and 71% for LGS respectively.

1. Introduction

The gas field is located at Surma Basin in the East Central part of Bangladesh, was discovered in 1960. The structure is an anticline with a north-south axis with size of structure is about 35 km long and 7 km wide[1]. Two distinct pay zones available in this gas field as Upper Gas Sand (UGS) at 4,530-4,825 ft. KB and Lower Gas Sand (LGS) at 8,880-9,145 ft. KB. In 1989, Intercomp-Kanata Management Ltd. (IKM) estimated the Proved reserve of 0.48 TCF in the UGS and 0.634 TCF in the LGS respectively. The produced gas is mainly methane (CH_4) with trace amount of other hydrocarbon like ethane, propane and butane[2].A total seven numbers of wells have so far been drilled in this field. The well completion type, respective perforation depth, sand and tubing size are shown in Table 1.

Table 1: Different well status

Well No	Sand	Perforation Depth, ft	Well Type	Tubing Size, inch
Well 1	UGS	4741	Vertical	3.5
Well 2	LGS	9042	Vertical	3.5
Well 3	LGS	9048	Vertical	3.5
Well 4	LGS	9202	Deviated	3.5
Well 5	LGS	9104	Vertical	4.5
Well 6	LGS	9003	Vertical	4.5
Well 7	LGS	9176	Vertical	4.5

Two wells from the LGS are not producing due to excessive water production. The total production from 5 wells is around 50 MMCFD. The detail production status of different wells is shown in Table 2.

Table 2: Current Production Scenarios

Well No	Production Rate			FWHP
	Gas	WGR	CGR	
	MMCFD	Bbl/MMCF	Bbl/MMCF	psia
Well 1	17.53	0.046	0.1053	1405
Well 2	Not Producing from 2007			
Well 3	10.09	12.1	1.76	1711
Well 4	11.89	1.425	0.9	1693
Well 5	Not Producing from 2006			
Well 6	2.2	14.6	0.88	1402
Well 7	8.75	0.734	1.45	1699
Total	50.46			

The gas field has 4 process plants with total capacity of 220 MMCFD as shown in Table 3. Three silica gel plants are connected with the lower gas sand while one desiccant glycol plant is connected with upper gas sand. The current production scenario is very much unimpressive since the field is producing less than one-fourth of its gas handling capacities. Two wells ceased their production due to excessive water production as shown in Table 2, but no initiative was taken to increase production from this field.

Table 3: Process Plants Capacity

No	Capacity (MMCFD)	Type
1	60	Desiccant Glycol
2	70	Silica Gel
3	45	Silica Gel
4	45	Silica Gel
Total	220	

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In this study, an attempt to increase gas production from this field was considered in various ways like change in the tubing size, adding more well, adding the compressor etc.; taking into account of maximum utilization of process plants capacities. Finally choose the optimum production scenario for this gas field from those options.

2. Methodology

Integrated production modeling provides an effective understanding of wells and field performance. It is a process of predicting the effects of changes through a systematic analysis of individual components and the impact of their interaction on field performance. Gas well performance cannot be analyzed without considering the reservoir, the production tubing and the processing facility, as each of these components affect the operation of the entire production network.

General Allocation Package (GAP™) software by Petroleum Experts is a total system-modeling tool. It model and optimize a gas field network comprised of wells, pumps, compressors, chokes and separators. The MBAL™ and PROSPER™ tools are used to model the reservoir and well respectively. Figure 1 is an overview of how the production system network is modeled[3].

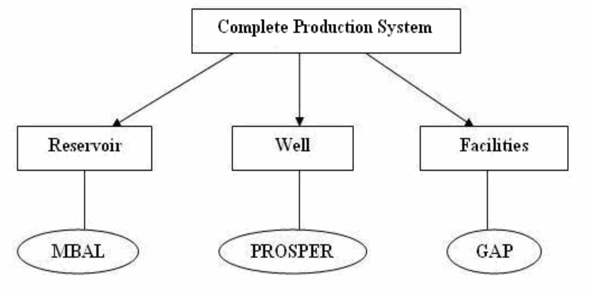

Fig 1: A complete Production System

3. Complete Production System Modeling

3.1 Modeling Individual Wells

To determine the reservoir deliverability as well as the vertical lift performance of the well is the key target of this section. This work includes build up a gas well model using the reservoir fluid PVT values, matching PVT, drawing the downhole equipments, constructing the IPR and vertical lift performance curves by choosing the best correlation for VLP[4]; finally validating the model to standard well test data by using Prosper™ .

Determination of optimum flow correlation is the main consideration while calculating the vertical lift performance of a well. A set of flow correlations[5] are available for different types of fluid and flow line geometry. The optimum flow correlation is obtained from the tubing correlation curve which measures the possible pressure drop of the system with various flow correlations as shown in Figure 2

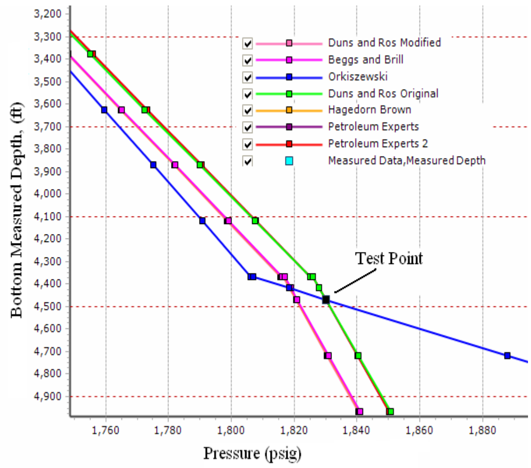

Fig 2: Pressure vs. Measure Depth curve for various tubing correlations for well # 1

An example case of well # 1; several correlation like Petroleum Experts 2, Orkiszewski and Dun & Ros Original correlations match closely with the field well test data point in terms of pressure and depth very closely as shown in Figure 2. Once the best matched flow correlation was found such as Duns and Ros Original correlation for well # 1, then the correlation is checked with a standard well test flow rate and pressure data. Differences in measured and calculated gas rate and bottomhole pressure as shown in Figure 3 and Table 4.

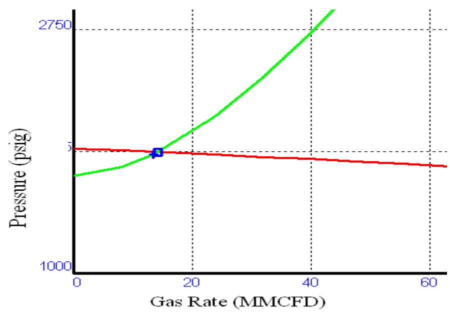

Fig 3: IPR-VLP curves for well 1

For well 1, the gas rate and bottomhole pressure from the model shows very close matching as shown in Table 4 to the standard well test data indicating the validation of well model.

Table 4: Well Model Validation

Gas Rate (MMCFD)		
Measured (Well Test)	Calculated by Model	% Difference
13.413	13.84	3.18
Bottomhole Pressure (psig)		
Measured (Well Test)	Calculated by Model	% Difference
1850	1870	1.06

In this study, determination of reservoir deliverability test is based upon the pressure test performed on various time between 1999 and 2007. All other wells like well # 1 are modeled in the similar manners and the matched correlation are listed in Table 5. Finally the best matched flow correlations as shown in Table 5 are used to analyze the change in tubing size, changing the effect of CGR, WGR and total system analysis.

Table 5: Matched flow correlation

Well No	Matched Correlations
Well 1	Duns and Ros Original
Well 3	Gray
Well 4	Petroleum Experts 2
Well 6	Duns and Ros Modified
Well 7	Petroleum Experts 2

A sensitivity analysis of tubing size and reservoir pressure shows that change in tubing size significantly improves the gas production from well # 1 under various reservoir pressures as shown in Figure 4.

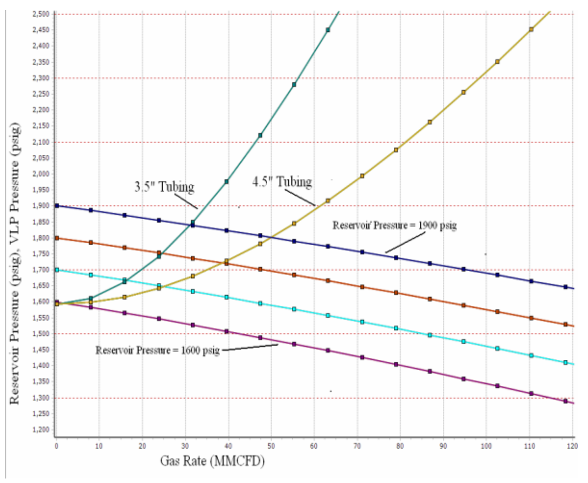

Fig 4: Tubing performance curve (VLP) for 3.5" and 4.5" with various reservoir pressures

For a reservoir pressure of 1800 psia, current tubing size (3.5") can produce a maximum of 24 MMCFD gas while a 4.5" tubing can produce up to 40 MMCFD of gas in the same reservoir pressure as shown in the Figure 4, indicating a considerable increase in daily gas production.

3.2 Estimating the Gas Reserve

This incorporates the classical use of Material Balance calculations for history matching through graphical methods[6] (like Havlena-Odeh, Campbell, and Cole etc.). Detailed PVT models has been constructed (black oil and compositional) for both reservoir layer by using MBAL™ tool.

The aim of this study is to find out or recalculate the previously estimated OGIP for both the UGS and LGS after quality checking of the available production data by material balance method. The quality check is based on what is physically possible and focused towards determining inconsistencies between data and physical reality. After 17 years of production from 1993, this study estimates the new reserves of 0.54 TCF and 1.26 TCF for UGS and LGS respectively by Material Balance Method of MBAL™ tools. The comparison of reserve is shown in Table 6

Table 6: Comparison of reserve estimation

Year	Method	Reserve (TCF)	
		UGS	LGS
1990 (IKM)	Volumetric (Proved, P1)	0.48	0.634
	Volumetric (Probable, P2)	0.354	0.775
	Total (P1+P2)	0.834	1.409
2010 (This Study)	Material Balance (MBAL™)	0.54	1.26

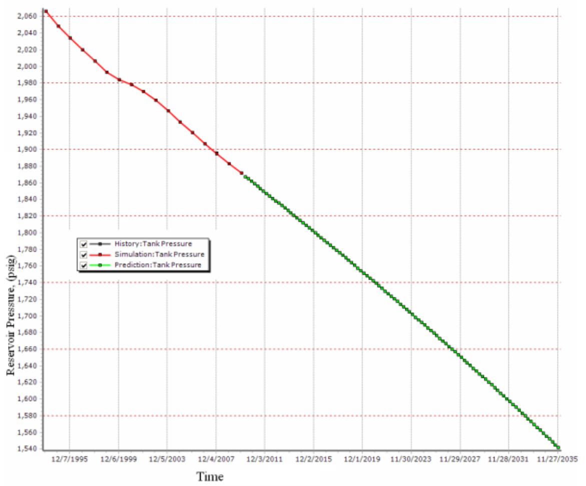

Fig 5: History matching and prediction of reservoir pressure for UGS.

The history match shows a very good fit for the reservoir pressure with volumetric depletion as shown in Figure 5. History match gives the confidence to the estimated OGIP and depletion characteristic of the reservoir. One can then proceed to wells and field wise optimization.

3.3 Integrated Production Modeling

GAP is used as the master controller to access simultaneously all well data and reservoir data by PROSPER™ and MBAL™ respectively. Integration of the well and reservoir elements provides the ability to understand the dynamic interactions of the complete petroleum engineering system. Well re-design and well stimulation efforts can be evaluated in context of the complete system.

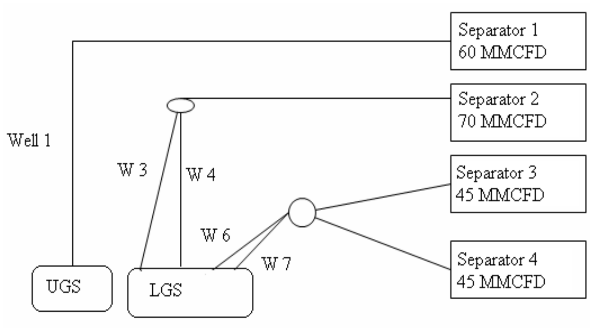

Fig 6: GAP network analysis, present field condition

The current well and separator configurations are shown in Figure 6. From the upper gas sand only well # 1 is producing which is connected to 60 MMCFD Desiccant Glycol Separator. Well # 3 and #4 in the lower gas sand are connected to 70 MMCFD Silica Gel. Well # 6 and #7, produced from LGS, jointly connected to 2x45 MMCFD silica gel separators.

Predicting measured reality is the ultimate goal of integrated studies and GAP offers a model validation utility to interrogate the system response[7]. The model validation utility enables well model performance to be updated based on latest test data ensuring consistent model prediction ability. Production data of 30 April 2010 are used for model validation, which is used as reference date for this study as shown in Table 7.

Table 7: Measured field data for model validation on 30th April 2010

Well Label	Sand	Measured			
		WHP	Gas Rate	WGR	CGR
		PSIG	MMCFD	STB/MMCF	STB/MMCF
Well 1	UGS	1405	17.53	0.046	0.106
Well 3	LGS	1711	10.09	12.1	1.76
Well 4	LGS	1693	11.89	1.425	0.9
Well 6	LGS	1402	2.2	14.6	0.88
Well 7	LGS	1699	8.75	0.734	1.45

Table 8: Estimated rate and difference with actual.

Well Label	Estimated				% Diff.
	Gas Rate	FBHP	WGR	CGR	Gas Rate
	MMCFD	Psig	STB/MMscf	STB/MMscf	MMCFD
Well 1	17.522	1852	0.05	0.11	0.045%
Well 3	9.992	2869	12.1	1.76	0.97%
Well 4	11.834	2641	1.43	0.9	0.47%
Well 6	2.21	1887	14.6	0.88	4.54%
Well 7	8.743	2405	0.73	1.45	0.08%

For a given field data like wellhead pressure with corresponding gas rate, WGR and CGR of the reference date, GAP estimated the gas rate, FBHP, WGR and CGR by each of the PROSPER well model developed previously with respective flow correlation. The network model's estimated rate are listed in Table 8. The entire reservoir-well system is correctly modeled. Now, one can proceed to study various cases.

4. Case Studies

Several field production strategies like increasing field production rate, feasibility of new wells etc are investigated. Results are compared in terms of ultimate recovery factor for next 25 years, field abandonment for wells and study the plateau rate of production. In addition, an attempt to find the best/ suitable production scenario for the gas field in terms of technical point of view.

This study discussed several field production strategies starting from May 2010 to December 2035 over a period of 25 years. Since the plant has large unused separator capacity, several cases are studied within the existing separator capacities and keeping the separator operating condition unchanged.

The different production plans are as follows.
1. Current plant separation conditions.
2. Upgrading the tubing size from 3.5'' to 4.5'' for well # 1, well # 3 and well # 4
3. Two additional drilling in the UGS and two more in LGS.
4. Using compressor for case 3

5. Results and Discussion

Currently the Gas Field has gas-handling capacity of 220 MMCFD. Moreover, two wells well # 2 and well # 5 ceased production from 2007. At this time, the field is producing a total of 50.46 MMCFD gas with 17.53 MMCFD from the Upper Gas Sand and 32.93 MMCFD from the Lower Gas Sand. The separator pressures are around 1073 psig. By keeping the separator pressure unchanged, each case will try to maintain a minimum allowable backpressure at each well.

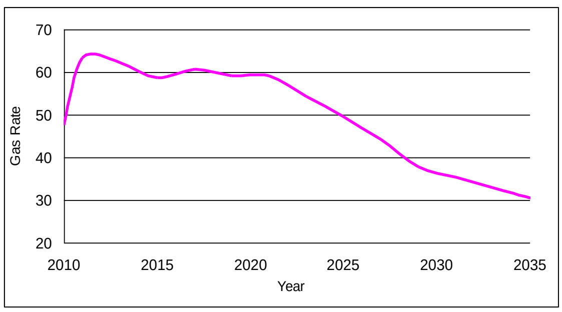

Fig 7: Current plant separation conditions

5.1 Present Situation

The present well configurations and production strategies produce an average of 50 MMCFD for next 12 years as shown in the figure 7.

The current plant configuration, upper gas sand shows a plateau for 20 years while in the LGS show stable production for 14 years. The total field results are shown in figure 7. The ultimate field recovery is 49% for UGS and 44% for LGS. The model predicted the reservoir pressure will be 1526 psig for UGS and 2090 psig for LGS in the year 2035.

5.2 Changing the Tubing Size

Changing the tubing size of all 3.5" well to 4.5" shows an increase in production. At a production rate of 65MMCFD (UGS 25, LGS 40) as shown in Figure 8, the field shows a very stable plateau for next 24 years from UGS with an ultimate recovery of 62 %. The LGS can produce a plateau production for 12 years with recovery of 54%. The model predicted final reservoir pressure will be 1346 psig for UGS and 1733 psig for LGS.

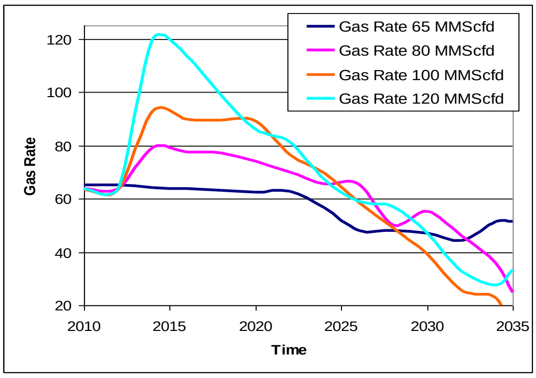

Fig 8: Total field production from all wells after changing the tubing size from 3.5'' to 4.5'' for well #1, well # 3 and well # 4

Furthermore, Initial higher rate also possible with 4.5" tubing size but with a lesser stable production. A maximum recovery of 68% can be achieved from the UGS by well # 1 if the well start producing at a rate of 40MMCFD by 4.5" tubing but this higher rate will not shows any plateau production

5.3 Addition of 4 new wells (2 wells in UGS, 2 wells in LGS)

In this case, 4 additional wells with 4.5" tubing configuration was investigated. It shows a higher initial rate is possible but no remarkable plateau as in Figure 9. The upper gas sand can produce 60 MMCFD with plateau time for 8 years while the lower gas sand do not shows any plateau. Two infill drilling in UGS increases the recovery up to 68%. Two additional well in LGS can produce 88 MMCFD initially but do not show a plateau production as well as do not improve the recovery factor (RF= 56%) significantly. The model predicts the reservoir pressure will be 1250 psig leads to abandonment of UGS in the year 2025. The lower gas sand will see abandonment in 2029 with abandonment pressure of 1650 psig

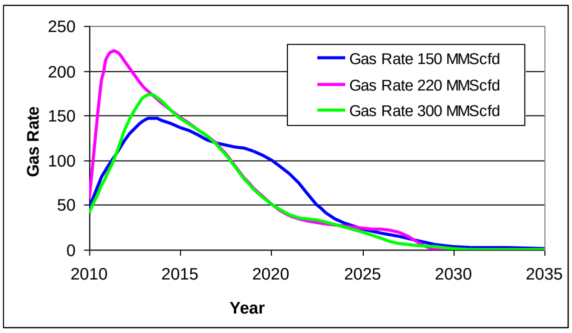

Fig 9: Total field production after two more infill drilling in the upper gas sand and two more infill drilling in lower gas sand

5.4 Addition of 4 new wells with compressor facilities

By lowering the well head pressure of the flowing well, field abandonment pressure can be further lowered and it is possible to achieve a higher recovery. An attempt to further increase gas production from this field also investigated by lowering the wellhead pressure and addition of compressor prior to the separator to maintain the separator operating pressure .

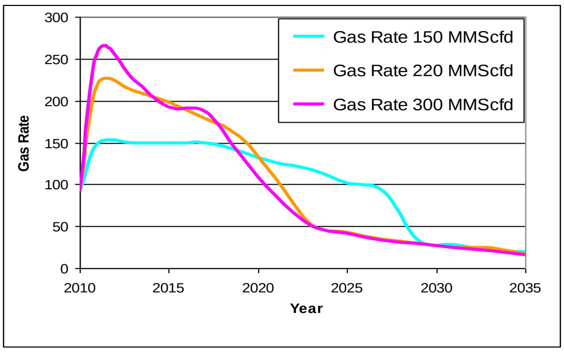

Fig 10: Total field production after two more infill drilling in the upper gas sand and two more infill drilling in lower gas sand (with compressor)

With 4 additional wells as in previous section and addition of compressor facilities, 150 MMCFD gas productions are possible with a total plateau of 8 years as in figure 10. The upper gas sand can deliver 60 MMCFD gas persistently for 14 years with a recovery of 92% and the abandonment reservoir pressure is 720 psig in 2029. The LGS can deliver 90 MMCFD with plateau of 8 years with recovery of 70%. The model also predicts the abandonment pressure of the reservoir will be 1115 psig for lower gas sand in 2035.

Using the compressor, a very high initial rate, even 270 MMCFD also possible but do not shows any plateau production as shown in Figure 10. The most optimum scenarios in each case study are listed together with current condition as shown in Table 9

Table 9: Comparison of different case studies

Description	Sand Layer	Optimum Rate	Plateau	RF
		MMCFD	Years	(%)
Current Condition	UGS	17	20	49
	LGS	33	8	44
Changing tubing size	UGS	25	24	62
	LGS	40	12	53.8
Four infilling drilling	UGS	60	8	68.5
	LGS	90	None	57
With Compressor	UGS	60	14	92.8
	LGS	90	8	70.4

6. Conclusions

Existing 3.5’’ production tubing in well # 1 cannot deliver more than 23 MMCFD from upper gas sand. By changing tubing size in well # 1 from 3.5’’ to 4.5’’ significantly improve the production rate. Recovery from the UGS can be maximized up to as high as 68% with existing one well with a high initial production rate by 4.5” tubing with no plateau. Addition of two infill drillings in the UGS also leads to a recovery of 68% from UGS.

Changing the existing tubing size for well # 3 and well # 4 in LGS, recovery increases around 10% from LGS. Current separator operating condition at 1073 psig, a maximum recovery of 57% is possible if two more wells added in LGS with an optimum gas rate of 90 MMCFD. Lowering the wellhead pressure and addition of compressor facilities prior to the separator to maintain the separator operating condition significantly increase the gas production from the reservoir.

7. Recommendation

This study investigates various production scenarios for this Gas Field. Since two wells, well # 2 and well # 5 ceased productions, new well should be drilled to maintain the field plateau. Gas production from well # 6 is around 2 MMCFD with a very high water production indicating the well going to be ceased production in near future due to liquid loading. The field should increase its production with justifying the economical criteria. Since the plant has unused process capacities, gas from newly drilled well can be supplied to the national grid in a very short period of time.

The pressure study / pressure test should be done for all wells on regular basis to get scenarios about the reservoir pressure statistics. The tubing size can be changed from 3.5’’ to 4.5’’ to improve the productivity from the existing well # 1, well # 3 & well #4. Increasing the tubing size of well #1 in UGS gives the almost equal ultimate recovery with 2 infill drilling in UGS leads to favor on increase tubing size rather than drilling 2 new wells in UGS. The scope of economic analysis was not included in this study. So strategic planning and economic analysis must be considered before considering any infill drilling or setting up a compressor facility. In addition, the production optimization should be recalculated for the new tubing size in future.

8. References

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