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Evaluation of natural gas production optimization in Kailashtila gas field in Bangladesh using decline curve analysis method

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Abstract

Decline curve analysis of well no KTL-04 from the Kailashtila gas field in northeastern Bangladesh has been examined to identify their natural gas production optimization. KTL-04 is one of the major gas producing well of Kailashtila gas field which producing 16.00 mmscfd. Conventional gas production methods depend on enormous computational efforts since production systems from reservoir to a gathering point. The overall performance of a gas production system is determined by flow rate which is involved with system or wellbore components, reservoir pressure, separator pressure and wellhead pressure. Nodal analysis technique is used to performed gas production optimization of the overall performance of the production system. F.A.S.T. Virtu Well™ analysis suggested that declining reservoir pressure 3346.8, 3299.5, 3285.6 and 3269.3 psi(a) while signifying wellhead pressure with no changing of tubing diameter and skin factor thus daily gas production capacity is optimized to 19.637, 24.198, 25.469, and 26.922 mmscfd, respectively.

Keywords: Gas production optimization; Decline curve analysis; Kailashtila gas field; Sylhet Basin; Bangladesh

Introduction

The Bengal Basin is situated in the northeastern part of the Indian plate (Fig. 1), and covers an area of 144,000 km^2. The Sylhet Basin is a sub-basin of the Bengal Basin, a tectonically complex province in northeastern Bangladesh (Hossain *et al*., 2010). This basin fill comprises about 22 km thick terrestrial to marine clastic sedimentary sequences with tiny carbonate rocks (Alam *et al*., 2003, Hossain *et al*., 2009). The Kailashtila gas field (KGF) lies in the eastern margin of the Sylhet Basin (Fig. 1), which is north-south trending asymmetric anticline (17 km long and 5 km wide on average) having a steeper western flank (25^0) and gentle eastern flank (11^0). Three main gas zones (upper, middle and lower) are identified in the KGF at depth ranging from ~2280 to 3045 m below the surface. The gas sands are referred to as Upper Gas Sand, Middle Gas Sand and Lower Gas Sand belonging to the Mio-Pliocene Surma Group (Bhuban and Boka Bil Formations). The gas sands were deposited as deltaic to marine environment under offshore bars and beach conditions (Imam, 2013). The reservoir pressure at Middle Gas Sand zone was 3495 psi(a) during February, 2009, whereas, reservoir pressure at KTL-4 was 3495 psi(a) (Ahmed, 2012). The gas producing rate for the KTL-4 was 16.00 mmscfd during May, 2013 (Anonymous, 2013).

Production optimization is applying for determination and implementation of the optimum values of parameters in the production system and to maximize hydrocarbon production rate to minimize operating cost under various technical and economic constraints (Guo *et al*., 2011). Production systems involve movement or transport of reservoir fluid from reservoir to surface requires energy to overcome the frictional losses or the pressure drop, and to optimize the desired production rates for both oil and gas wells. In system analysis, deliverability can be used a method where input and output pressure is identical which called Nodal analysis (Hossain, 2008).

Well deliverability is being calculated from inflow performance relationship (IPR) and vertical lifting performance (VLP) curve intersection. The IPR involves the conditions and parameters of reservoir while VLP involves with the production well. Tubing flowing pressure operation is possible from surface and necessary to calculate total pressure loss (Economides *et al*., 1994, Rahman, 2012).

Short term optimization of well performance can be done by improving inflow performance, changing the tubing or choke size and long term optimization of well performance can be done by declining reservoir pressure, installation of gas lift (Jansen *et al*., 2004). For gas production optimization, a series of pressure drop occur when reservoir fluid moves from the reservoir to surface through wellbore, tubing string and process facilities (Mogensen, 1991). In multi-reservoir gas fields, gas production rate can be optimized by branch-systems including reservoirs and a surface branch-system without reservoirs (Roh *et al*., 2006).

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Gas-lift optimization problem has been investigated by numerous authors (Buitrago *et al*., 1996, Kanu *et al*., 1981, Martinez *et al*., 1994, Wang et *al*., 2002) using different optimization techniques (the equal-slope method, a Quasi-Newton method, and a genetic algorithm). Fang and Lo (1996) developed a linear programming model to optimize lift-gas rates to wells in large fields subject to multiple flow rate and pressure constraints (Wang, 2002). In these studies, different gas injection scenarios were evaluated using gas-lift performance curves for individual wells, ignoring interactions between wells (Dutta-Roy *et al*., 1997, Wang, 2002). Conversely, oil production in the Prudhoe Bay and Kuparuk River fields is constrained by the gas handling limits of surface facilities. It was presented the Western Production Optimization Model (WPOM) for the Prudhoe Bay field. This model maximizes oil production while minimizing the need for gas processing that allocates the oil rate and gas rate to surface facilities and wells based on the "incremental gas oil ratio (GOR)" concept (Barnes *et al*., 1990, Wang, 2002). It has been reported that (Litvak *et al*. 1997) an integrated reservoir and gathering system model of the Prudhoe Bay field, and employed various heuristic methods to optimize well connections to manifolds. Gas-lift optimization curves for individual well are derived through the measurement of gas-liquid ratio, liquid well rate and water cut (Wang, 2003, Hatton and Potter, 2011). Lo and Co-workers (Lo and Holden 1992) established a linear programming (LP) model to optimize daily oil production rate through allocating well rates subject to multiple flow rate constraints which was used as a screening tool to evaluate development opportunities at the Kuparuk River field. It was applied a neural network to

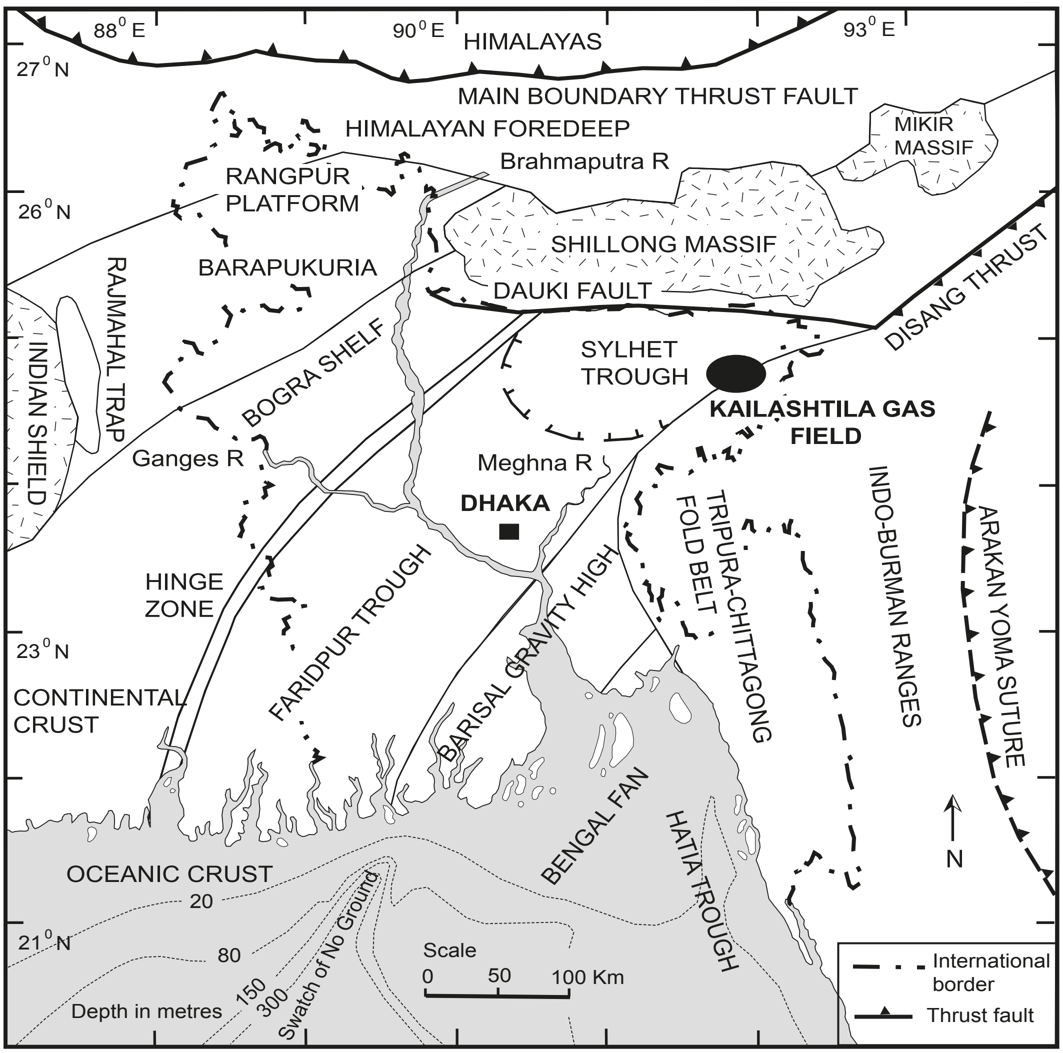

Fig. 1. Location map of the study area and major geological features of the Bengal Basin and adjoining areas (modified after Hossain *et al.*, 2013).

determine optimal allocation of lift-gas to wells subject to multiple gas constraints in the same field (Stoisits *et al*., 1994, Stoisits *et al*., 1992, Wang, 2002). The neural network was trained by results obtained from Nodal analysis simulations. In 1997, it was addressed the production optimization problem at Kuparuk River field using a genetic algorithm (Stoisits *et al*., 1992, Wang, 2002).

Continuous gas-lift is the most popular artificial lift method applied in offshore operations worldwide (Clegg *et al*., 1993, Ship Shoal 208 is mainly a gas-lifted field (~50 oil wells: 45 gas-lift and 4 compressors to inject gas) which located about 85.5 km offshore from the coast of Louisiana. These four compressors deliver nearly 30,000 MCF (1,000 standard cubic feet) to the 45 gas-lifted wells, which is merely 60% of the optimum supply. Similar fields in the Gulf of Mexico have had success with gas-lift optimization systems like Ship Shoal 208 (Marietta, 2005). In a typical continuous gas-lift installation, a standard adjustable choke controls the gas injection rate at every individual well, and this injection rate often varies due to fluctuations in the gas-lift supply pressure (Mitra, 2012). Thus, field operators manually regulate the gas-lift rate on a trial-and-error basis in the well (Gang and Golan, 1989).

Besides, using PIPESIM software in the Saldanadi gas field it has been demonstrated that changing reservoir pressure and outlet pressure which optimized gas production rate significantly (Haq *et al*., 2010). On the other hand, GAP software calculation is applied to estimate the gas production optimization of Saldanadi gas field and KGF by changing tubing ID and separator pressure resulting optimized the gas production (Guo *et al*., 2007, Ahmed, 2012). Similarly, GAP software is used to evaluate gas production optimization of KGF for changing tubing ID and separator pressure which also optimized the gas production (Ahmed, 2012). In the Habiganj gas field, it has been showed that by changing the value of skin, tubing ID and perforation depth optimized gas production (Rahman, 2012). The aim of this paper is to optimized natural gas production by using F.A.S.T. Virtu Well™ software of KTL-4, Kailastila gas field in northeastern Bangladesh.

Geological setting

The Bengal Basin constitutes the largest delta complex in the world, which is well known for development of thick sedimentary sequence of Early Cretaceous to Holocene in age (Alam *et al*., 2003). The basin, as a remnant ocean basin, formed due to northwestward drift of the Indian plate and its oblique collision through the Sino-Tibetan plate and Burmese plate (Ingersoll *et al*., 1995, Alam *et al*., 2003). This oblique subduction has generated the westward migration of accretionary wedges (Dasgupta and Nandy, 1995, Gani and Alam, 1999, Alam *et al*., 2003). The Bengal Basin is bounded to the west by the Indian Shield Platform, to the east by the Indo-Burman Ranges, to the north by the Shillong Massif, and to the south it opens to the Bay of Bengal (Fig. 1). The KGF is bounded by the Beanibazar structure to the east, Sylhet structure to the north and Fenchuganj structure to the south. A very minor saddle separates the structure from Fenchuganj anticline and a thrust fault near the northern plunge of the structure that also separates it from the Sylhet structure. The anticline structure is ~6 km long and 3 km wide (Anonymous, 2012).

The Sylhet Basin is a large elongated trough containing a thick sedimentary sequence typically of Tertiary age. This basin is important for many researchers owing to its hydrocarbon reserves, and contains some subsurface synclinal and anticlinal structures. Stratigraphic succession of the Sylhet Basin is shown in Table I. The Paleocene to Late Eocene Jaintia Group (Tura Sandstone, Sylhet Limestone and Kopili Shale) consists mainly of sandstones, mudstones, carbonaceous materials, nummulitic limestones and fossiliferous sediments. The Jaintia Group was deposited in shallow marine to deltaic environments (Johnson and Alam, 1991, Khan, 1991, Reimann, 1993, Alam *et al*., 2003, Hossain *et al*., 2009, 2010). The Late Eocene to Early Miocene Barail Group (Jenam and Renji Formations) consists mainly of sandstones with alternating siltstones and mudstones. This group was accumulated in tide-dominated shelf environments (Alam, 2003). The contact between Barail and Surma Groups is erosional.

The Middle to Late Miocene Surma Group (Bhuban and Boka Bil Formations) consists of alternating sandstones, siltstones and mudstones subsequently deposited in deltaic to marine environments (Banerji, 1984, Reimann, 1993, Hossain *et al*., 2009). The upper contact of the Surma Group is erosional. The Late Miocene to Pliocene Tipam Group (Tipam Sandstone and Girujan Clay) consists primarily of sandstones, siltstones, occasionally conglomerate and variegated claystones. The Tipam Group was deposited in fluvial to lacustrine environments (Johnson and Alam, 1991, Reimann, 1993, Hossain *et al*., 2009, 2010). The Pliocene to Pleistocene Dup Tila Group consists of sandstones with subordinate siltstones and shales. This group is deposited in channel and floodplain environments (Johnson *et al*., 1991). Late Pleistocene Dihing Group consists mostly of sandstone and shale subsequently accumulated in fluvial and/or piedmont depositional environments (Khan, 1991; Hossain *et al*., 2009). The uppermost part of the succession is recent alluvium consists chiefly of sand, silt and clay.

Table I. Stratigraphy of the Sylhet Basin, Bangladesh (after Hossain *et al.*, 2009, 2010).

Age	Group	Formation	Lithology	Depositional Environments
Recent	Alluvium	Alluvium	Sand, silt, clay	Fluvial
Late Pleistocene	Dihing	Dihing	Sandstone, shale	Fluvial
Pliocene-Pleistocene	Dupitila	Dupitila	Sandstone, shale	Fluvial
Late Miocene-Pliocene	Tipam	Girujan Clay	Clay, sandstone	Fluvial, lacustrine
		Tipam Sandstone	Sandstone, shale	Fluvial
Middle-late Miocene	Surma	Bokabil	Sandstone, shale	Marine, deltaic
		Bhuban	Sandstone, shale	
Late Eocene-early Miocene	Barail	Renji	Sandstone, shale	Shallow marine, deltaic
		Jenam	Shale, sandstone	
Late Eocene	Jaintia	Kopili Shale	Shale, minor lst.	Shallow marine, deltaic
Early-middle Eocene		Sylhet Limestone	Limestone	Shallow marine
Paleocene-early Eocene		Tura Sandstone	Quartz arenites	Shallow marine

Materials and methods

Production, well performance and reservoir data for this study were collected from Sylhet Gas Field Limited (SGFL) through Petrobangla (Ahmed, 2012) and annual reports of SGFL. Reservoir absolute open flow (AOF) type curve analysis and Rawlins-Schellhardt (P^2) AOF type curve analysis have been used to evaluate gas production optimization in the KGF. This is based on IPR-VLP curve at Nodal analysis approach and also F.A.S.T. VirtuWell™ software. AOF curve is indicating IPR Curve and tubing performance curve (TPC) is indicating VLP curve. Pressure loss correlation is modified after Beggs (Beggs, 1991).

In reservoir AOF type curve analysis, casing data, tubing data, perforation data, and wellbore properties, TPC data, specifies different tubing scenarios data and fluid properties are entered into the F.A.S.T. VirtuWell™ software. AOF curve and gas AOF/TPC curve were automatically produced. This gas AOF/TPC curve represents the relationship in the form of a pressure versus flow rate graph as well as operating point where TPC crosses the AOF curve. Additionally, for Rawlins-Schellhardt (P^2) AOF type curve analysis, TPC data, specifies different tubing scenarios data, reservoir AOF data entered into the software which automatically generated TPC curve and gas AOF/TPC curve. The resulting intersection points with the curves (Figs. 2b and 3b) are shown in the operating Table II and III.

Results and discussion

Optimization of production operations can be a major factor on increasing production rate and reducing production cost in a variety of technical and economic aspects. In the present work it is determining the optimal production rates, maximize daily operational objectives subject to multiple flow rate and pressure constraints. For petroleum field, the rate allocation problem can be formulated as a separable programming (SP) problem whose objective and constraint functions are sums of functions of one variable which is solved by various linear optimization techniques (Wang, 2003). Production rate of a vertical well operating through the flow rate by considering the pressure drop over the following elements including the reservoir (near wellbore area and completion), tubing up to tubing head, choke, and flow line (Jansen *et al*., 2004). It was determined optimal allocation of lift-gas to wells subject to multiple gas constraints at Kuparuk River field (Stoisits *et al*., 1992, 1999). Short-term production optimization WPOM was applied in the Prudhoe Bay field of the North-Slope of Alaska, and to long-term reservoir development studies for two fields in the Gulf of Mexico was applied and its result demonstrated the effectiveness of the approach (Barnes *et al*., 1990, Stoisits *et al*., 1999, Wang, 2003). Continuous gas-lift method was employed in offshore operations (Clegg *et al*., 1993). But present study is working with Nodal analysis technique applying long-term production optimization. Besides, this analysis is done at KTL-04 vertical well using F.A.S.T. Virtu Well™ software by decreasing reservoir pressure with changing wellhead pressure and other considerations like tubing diameter and skin factor are approximately be constant.

For gas production optimization at KTL-4 production systems are involved with the movement or transport of reservoir fluid from reservoir to surface requires energy to overcome the frictional losses or the pressure drop. In both inflow and out flow sections that formed of AOF and TPC, fluid flows due to pressure variation which is measured at Table II and Table III. Reservoir fluid properties of KTL-04 are also involved to overcome the frictional losses and/or the pressure drop which ultimately increased to the gas flow rate (Economides *et al*., 1994, Hossain, 2008).

(Table II). The reservoir AOF type curve in Fig. 2a was initially generated by the reservoir properties of KTL-04 including porosity, water saturation, permeability, reservoir pressure, drainage area, initial gas in place, perforation angle, skin factor etc mentioned as IPR_1, IPR_2, IPR_3 and IPR_4. The intersection points are determined from the intersection of the AOF curves (IPR_1, IPR_2, IPR_3 and IPR_4) and TPCs (VLP_1, VLP_2, VLP_3 and VLP_4) that are the relationship in the form of a pressure versus flow rate graph (Fig. 2b). This graph is also indicating IPR and VLP curve. It is a form of Nodal analysis technique (Beggs, 1991, Hossain, 2008). The intersection points are 3346.8, 3299.5, 3285.6 and 3269.3 psi(a), respectively which indicating pressure points and 19.637, 24.198, 25.469 and 26.922 mmscfd, respectively which indicating flow rate points for AOF 1 (Table II). The IPR curve is mainly generating pressure points that are involved the conditions and parameters of reservoir pressure. However, the VLP curve which generating flow rate points and are primarily involving the parameters of production

Table II. Operating points result at reservoir AOF type curve analysis for KTL-04 well (pressure *vs.* flow rate), Kailashtila gas field, Bangladesh.

AOF	$P_{SF}A$ Psi(a)	Q_GA mmscfd	$P_{SF}B$ Psi(a)	Q_GB mmscfd	$P_{SF}C$ mmscfd	Q_GC mmscfd	$P_{SF}D$ Psi(a)	Q_GD mmscfd
1	3346.8	19.637	3299.5	24.198	3285.6	25.469	3269.3	26.922
2	3347.8	19.652	3300.9	24.213	3287	25.483	3270.9	26.937
3	3348.9	19.667	3302.2	24.228	3288.4	25.498	3272.6	26.953
4	3350.0	19.682	3303.6	24.243	3289.9	25.513	3274.1	26.968

Table III. Operating points result at Rawlins-Schellhardt (P^2) AOF type curve analysis for KTL-04 well (Pressure *vs.* flow rate), Kailashtila gas field, Bangladesh.

AOF	$P_{SF}A$ Psi(a)	Q_GA mmscfd	$P_{SF}B$ Psi(a)	Q_GB mmscfd	$P_{SF}C$ mmscfd	Q_GC mmscfd	$P_{SF}D$ Psi(a)	Q_GD mmscfd
1	3346.8	19.637	3299.5	24.198	3285.6	25.469	3269.3	26.922

Table IV. Comparison between the two models results for KTL-04 well, Kailashtila gas field, Bangladesh.

Declined Reservoir Pressure, Psi(a)	Suggested Wellhead Pressure, psi(a)	Optimized Gas Production, mmscfd
3346.8	2000	19.637
3299.5	1500	24.198
3285.6	1300	25.469
3269.3	1000	26.922

Reservoir AOF type curve analysis for KTL-04

The result of the reservoir AOF type curve analysis is obtained from the intersection points (operating points) well. Conversely, flow rate points 19.637, 24.198, 25.469 and 26.922 mmscfd indicating well deliverability. However, AOF 2, 3 and 4 are also reporting both pressure declination and deliverability, respectively (Table II). Well deliverability rate is directly related to gas production rate, when well deliverability increased subsequently increased gas production rate (Economides *et al.*, 1994). The well deliverability rate in the KTL-04 is 19.637, 24.198, 25.469 and 26.922 mmscfd suggesting gas productions rate which are higher than present gas production rate of 16.00 mmscfd.

Rawlins-Schellhardt (P^2) AOF type curve analysis for KTL-04

The result of the Rawlins-Schellhardt (P^2) AOF type curve analysis is obtained from the intersection points (operating

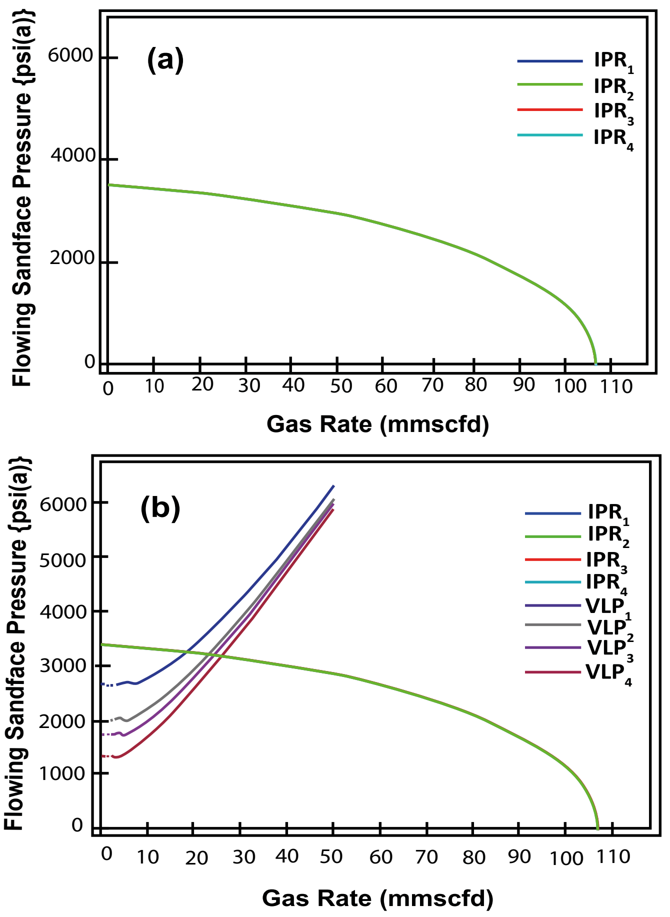

Fig. 2. (a) AOF curve, (b) Gas AOF/TPC curve, for KTL-04 well using reservoir AOF type curve analysis, Kailashtila gas field, Bangladesh. Abbreviations: IPR_1, IPR_2, IPR_3 and IPR_4, first second, third and four inflow performance relationship (IPR) curve; VLP_1, VLP_2, VLP_3 and VLP_4, vertical lift performance (VLP) curve of A, B, C and D tubing.

points) (Table III). In the Rawlins-Schellhardt (P^2) type curve analysis, it is initially investigated TPC or VLP curve (3a) which is generated by the production well properties of KTL-04 including tubing data, casing data, wellhead pressure, fluid ratios, flow path etc mentioned as VLP_1, VLP_2, VLP_3 and VLP_4 for A, B, C and D tubing. The intersection points are determined from the intersection of the AOF curve (IPR_1) and TPCs (VLP_1, VLP_2, VLP_3 and VLP_4) that are the relationship in the form of a pressure versus flow rate graph (Fig. 3b). This graph is also corresponding to the IPR and VLP curve. It is a form of Nodal analysis technique (Beggs, 1991, Hossain, 2008). The intersection points are 3346.8, 3299.5, 3285.6 and 3269.3 psi(a), respectively which indicating pressure points and 19.637, 24.198, 25.469 and 26.922 mmscfd, respectively which indicating flow rate points for AOF 1 (Table III). These intersection points are determined from the IPR and VLP curve (Fig. 3b). The pressure points 3346.8, 3299.5, 3285.6 and 3269.3 psi(a) are reflecting pressure declination. On the other hand, flow rate points such as 19.637, 24.198, 25.469, and 26.922 mmscfd are indicating well deliverability. Well deliverability rate is directly related gas production rate, where gas production rate increases with the increase of well deliverability (Economides *et al.*, 1994). The well deliverability rate 19.637, 24.198, 25.469, and 26.922 mmscfd are very similar to that of Table II, indicating gas production rate is higher than present gas production rate of 16.00 mmscfd.

Comparison between two types of curve analytical result for KTL-04 well

For reservoir AOF type curve analysis, initially AOF/IPR curves are generated by the reservoir properties of KTL-04 mentioned as IPR_1, IPR_2, IPR_3 and IPR_4 (Fig. 2a). It represents the inclination of the reservoir pressure which is formed of inflow of the node (Beggs, 1984, Jansen *et al.*, 2004, Hossain, 2008). For Rawlins-Schellhardt (P^2) AOF type curve analysis, in the early stage TPCs or VLP curves are generated by the production well properties of KTL-04 mentioned as VLP_1, VLP_2, VLP_3 and VLP_4 (Fig. 3a). It represents the gas production rate through tubing that is formed of outflow of the node (Beggs, 1984, Hossain, 2008).

At the reservoir AOF type curve analysis these AOF/IPR curves are intersected with TPCs/VLP curves while Rawlins-Schellhardt (P^2) AOF type curve analysis TPCs/VLP curves are also intersected with AOF/IPR curve (Figs. 2b and 3b) which concurrently represent as a form of Nodal analysis technique. Both curves are generated at the same time through double analyses due to produce AOF/TPC or IPR/VLP curve (Figs. 2b and 3b). It is needed reservoir and well performance data simultaneously (Beggs, 1991, 1984, Economides *et al*., 1994, Jansen *et al*., 2004, Hossain, 2008), and also used wellhead pressure which is suggested autonomously (Economides *et al*., 1994). Therefore, both of these curve analysis indicating wellhead pressure is decreased respectively with reservoir pressure Fig. 4 and Table V.

Comparison between the reservoir AOF and Rawlins-Schellhardt (P^2) AOF type curves in the KTL-04 well illustrated that both operating points of first row are similar (Table IV). If the reservoir pressure of this well is

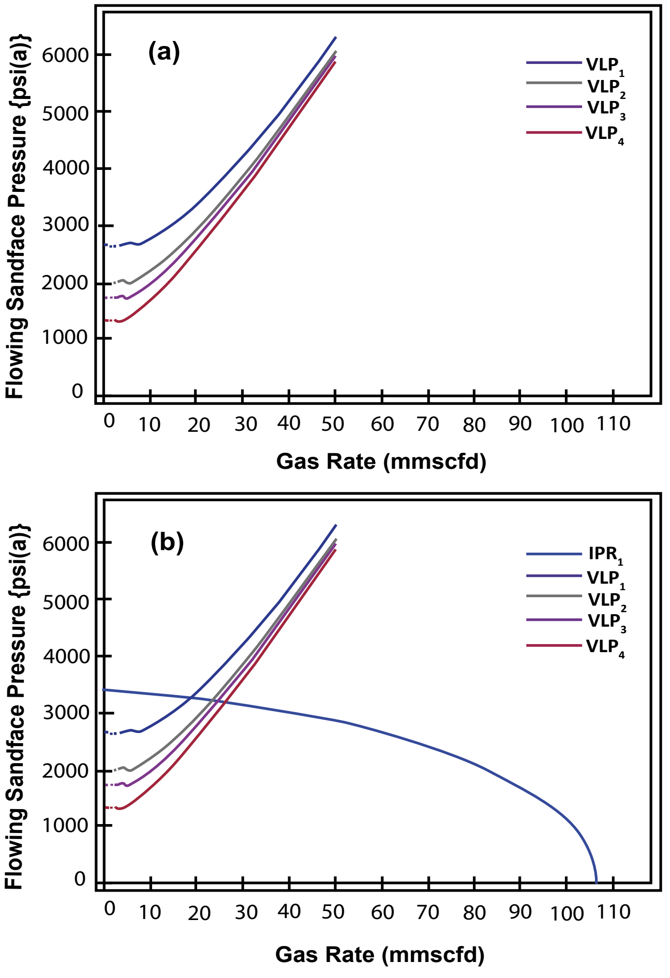

Fig. 3. (a) TPC curve, (b) Gas AOF/TPC curve, for KTL-04 well using Rawlins-Schellhardt (P^2) AOF type curve analysis, Kailashtila gas field, Bangladesh. Abbreviations: VLP_1, VLP_2, VLP_3 and VLP_4, vertical lift performance (VLP) curve of A, B, C and tubing; IPR_1 first inflow performance relationship (IPR) curve.

3346.8, 3299.5, 3285.6 and 3269.3 psi(a) though the wellhead pressure is 2000, 1500, 1300, and 1000 psi(a), respectively. For gas production optimization, pressure drop occur when reservoir fluid moves from the reservoir to the surface (Mogensen, 1991). This analysis demonstrated that reservoir pressure is dropped 3495 psi(a) to 3346.8, 3299.5,

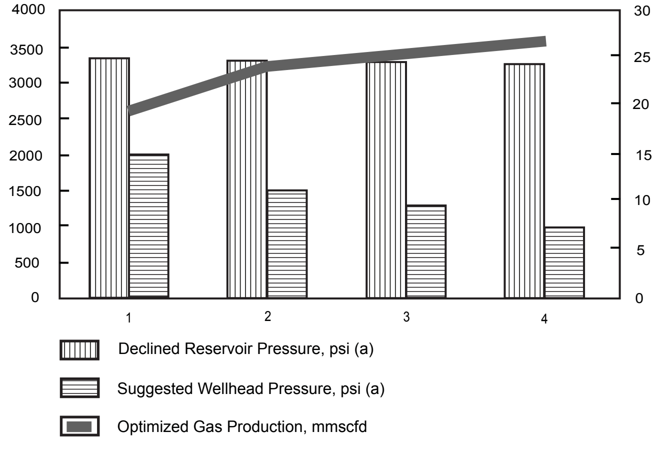

Fig. 4. Gas production rate optimization for KTL-04 well, Kailashtila gas field, Bangladesh.

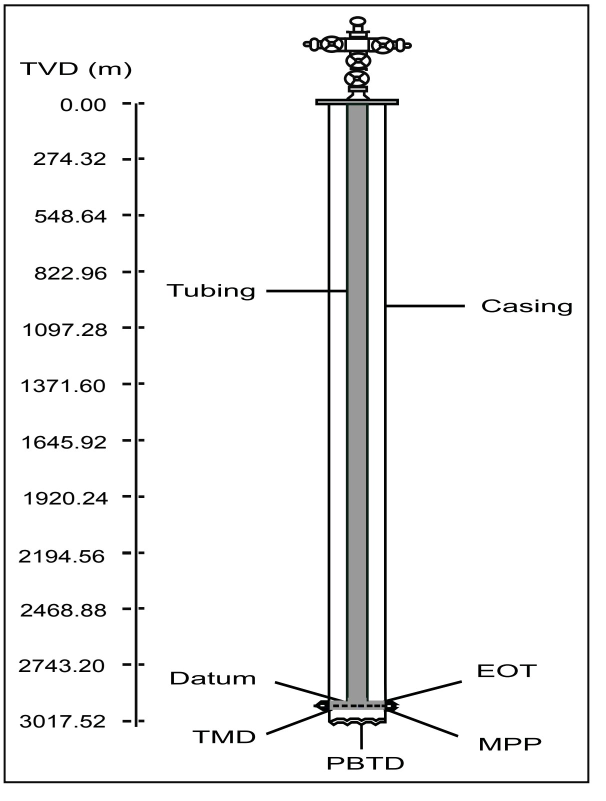

Fig. 5. Schematic diagram of vertical wellbore configuration for KTL-04 well, Kailashtila gas field, Bangladesh. Abbreviations: TVD, True vertical depth; TMD, tubing measured depth; PBTD, plug bottom total depth; MPP, midpoint of perforation; EOT, end of tubing depth.

3285.6 and 3269.3 psi(a), respectively. The gas producing rate in the well is changed to 19.637, 24.198, 25.469 and 26.922 mmscfd, respectively. Therefore, gas production rate is increased through inclination of the reservoir pressure (Economides *et al*., 1994), and gas producing rate is increased than present production and it is increased to 19.637, 24.198, 25.469 and 26.922 mmscfd, respectively with declined reservoir pressure. The proved gas production optimization result in the KTL-04 well is shown in Fig. 4 and Table V. From left side of the Fig. 4, it is mentioned that declining reservoir pressure and suggesting wellhead pressure rate concomitantly formed two discrete mode columns which showed gradual declining rate on the right side (Fig. 4). The optimized gas production rate formed an upward rising curve which indicated increasing gas production rate with declined reservoir and wellhead pressure, respectively. Using F.A.S.T. VirtuWell™ software it is concluded that the current vertical wellbore configuration of KTL-04 tubing measured depth 2945.89 m, casing plug bottom total depth 3021.18 m, midpoint of perforation 2944.06 m and datum depth 2944.06 m (Fig. 5). It mentioned that depth (2944.06 m) of the midpoint of perforation (MPP) is mainly related to the end of tubing depth (EOT). In this configuration, EOT is above the MPP for the KTL-04 where the fluid flow is within the casing until it reached to the EOT point. However, the tubing with casing ID calculation in this study showed the datum depth of 2944.06 m. It is a reference point for the calculations that are either derived from the sandface (reservoir) to the datum and/or from the datum to the wellhead (Fig. 5).

Table V. Evaluation of natural gas production results in the KTL-04 well, Kailashtila gas field, Bangladesh.

Well No	Reservoir Pressure, psi(a) (till to Feb, 2009)	Gas Production, mmscfd (till to May, 2013)	Reservoir Pressure Declination, Psi(a)	Suggested Wellhead Pressure, psi(a)	Optimized Gas Production, mmscfd
KTL-04	3495	16.00	3346.8	2000	19.637
			3299.5	1500	24.198
			3285.6	1300	25.469
			3269.3	1000	26.922

Conclusion

The natural gas production optimization in KTL-04 well from the Kailashtila gas field in northeastern Bangladesh has been identified by decline curve analysis. KTL-04 is one of the major gas producing well of Kailashtila gas field, which producing 16.00 mmscfd. The overall performance of a gas production system is determined by flow rate, which is involved with system or wellbore components, reservoir pressure, separator pressure and wellhead pressure. Nodal analysis technique is used to performed gas production optimization of the overall performance of the production system. F.A.S.T. Virtu Well™ analysis suggested that declining reservoir pressure 3346.8, 3299.5, 3285.6 and 3269.3 psi(a) while signifying wellhead pressure with no changing in tubing diameter and skin factor thus daily gas production capacity is optimized to 19.637, 24.198, 25.469 and 26.922 mmscfd, respectively. Therefore, natural gas production evaluation through changing reservoir pressure has been a key to unlocking natural gas reserves in Bangladesh.

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