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Nodal and least-cost analysis on the optimization of natural gas production system constraints to extend the plateau rate of a conceptual gas field

Elia Wilinasi Sikanyika [a,b], Zhengbin Wu [a,b,c,*], Husham Ali Elbaloula [d], Maurice Oscar Afiakinye [a,b], Armel Prosley Mabiala [a,b], Shu Jiang [a,b]

[a] Key Laboratory of Theory and Technology of Petroleum Exploration and Development in Hubei Province, China University of Geosciences, Wuhan 430074, China
[b] Key Laboratory of Tectonics and Petroleum Resources Ministry of Education, China University of Geosciences, Wuhan 430074, China
[c] Department of Chemical and Petroleum Engineering, University of Calgary, Calgary, AB T2N 1N4, Canada
[d] Alfa Star Global Oil Field Services LLC, P.O. Box 414268, Dubai, United Arab Emirates

A R T I C L E I N F O

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A B S T R A C T

The supply of natural gas in any country is determined by energy demand. Furthermore, supply agreements specify that gas should be supplied at a constant rate for a specified period. However, due to the decline in reservoir pressure as gas fields continue to produce, high constant rate production is usually uncertain, and the plateau may not reach the agreed-upon period. Therefore, this study was conducted to optimize gas production system constraints and extend the production plateau rate of a conceptual dry gas field. The field was made up of the sand packages CF2 upper, CF2 lower, CF1 upper, and CF1 lower. A total of 1316.9 Bscf were assumed to be the estimated gas field reserves, and 423.3 Bcf were assumed to be the remaining economically recoverable gross 2 P sales of natural gas. The field also contained natural gas at the Miocene and five production wells, numbered PW-1, PW-2, PW-3, PW-4, and PW-5. The field's estimated average constant gas production rate as of July 2021 was 85 MMscfd. The field's gas demand was forecasted in three phases, with the third beginning on November 1, 2019, at a rate of 130 MMscfd. After applying Nodal Analysis with the help of Integrated Production Modelling (IPM) and Least Cost Analysis methods, the study found that the gas production plateau of that field started to decline on March 1, 2017, after 1 year and 5 months of production when constrained to 130 MMscfd. However, after modifying the constraints to match various assumed production histories, it was discovered that the plateau would start to decline on June 1, 2023, after 8 years of production. Therefore, eight possible combinations of varying the three production constraints were developed and simulated to examine their effect on extending the field production plateau. These constraints were separator pressure, tubing size, and the number of layers perforated. The best combination was to lower the separator pressure to 725 psia, increase the tubing size to 4 inches, and perforate three more zones (zones I, C, and D). This was the only combination that appeared to extend the production plateau for 8 years until October 1, 2031, as required in the 16 years gas sales agreement (GSA). This approach was economically compared to the options of using a compressor and drilling future wells, and it was found to be 34.05% cheaper than the compressor usage option and 98.25% cheaper than drilling a well. As a result, the operators of this conceptual gas field are advised to adopt this approach to extend the field's plateau.

1. Introduction

Natural gas field production optimization refers to various activities of measuring, analyzing, modelling, prioritizing, and implementing actions to enhance the productivity of a field (Guo, 2011; Shah et al., 2020). A natural gas production system may be optimized by selecting a combination of its component characteristics that will give a maximum production rate at a lower cost (Beggs, 2003). Therefore, different approaches and technologies are used in gas production upstream to give different ways of optimizing the production (Guo, 2011).

* Corresponding author. Key Laboratory of Theory and Technology of Petroleum Exploration and Development in Hubei Province, China University of Geosciences, Wuhan 430074, China. .

E-mail addresses: elia.sikanyika98@gmail.com (E.W. Sikanyika), wuzb@cug.edu.cn (Z. Wu), hushamali66@gmail.com (H.A. Elbaloula), mauriceoscar58@gmail.com (M.O. Afiakinye), prosleymab@gmail.com (A.P. Mabiala), jiangsu@cug.edu.cn (S. Jiang).

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A full system for the production of natural gas consists mainly of reservoir, well, flow line, compressors, separators, and pipelines for transportation (Economides, 2013). The reservoir provides the well-bore with gas (Jansen, 2017). The well creates a way for produced gas to flow from down the hole to the ground and proposes a way to handle the rate of production of gas (Foss et al., 2018). The flow-line transports the obtained gas to the separators (Foss et al., 2018). The separators eliminate water and condensate from the gas stream. The transportation of gas across pipelines to sales points is done by compressors (Guo, 2011). Fig. 1 illustrates the single-well production system.

In the production and development phases of a natural gas project, a lot of design and operational choices have to be made (Khor et al., 2017). This will incorporate adequate recovery methods, number of production wells, area of wells, set up processing capacity, timing of drilling, storage and transportation services, production rates, and decommissioning timing (Jahn et al., 2008; Schiozer et al., 2019). These options will all be made in order to maximize the net present value (NPV) for the whole project (Hinkin, 2017; Aliaga and Huerta, 2017).

However, when natural gas producers begin to sale produced natural gas to their customers, the sales contract usually specifies the supply of natural gas at a plateau level or constant rate for the agreed period (Johansen, 2011; Söderbergh et al., 2010). But, once the pressure in the reservoir falls to the level at which is less than the sum of the pressure drops required to transport the gas from the reservoir to the pipeline, then the plateau production rate can no longer be maintained (Aliaga and Huerta, 2017; Wang, 2003). Thus, it is important to optimize the production system at early stages to ensure that reservoir energy is maintained throughout so as to deliver the required quantity of gas for the agreed schedule (Aliaga and Huerta, 2017; Dake, 1998; Latif et al., 2019). As the result, this study proposed optimization of natural gas production system constraints to extend the production plateau rate of the conceptual gas field.

2. Literature review

The analysis of the oil and gas production system and the concept of production optimization became necessary when the oil and gas reservoirs started to suffer from severe depletion. Because of the uncertainty and high risk associated with exploring new fields, the need to use all available options within the existing reservoirs became critical (Tetoros, 2015). To describe a variety of procedures in the oil and gas industry the term production optimization was applied (Guo, 2011).

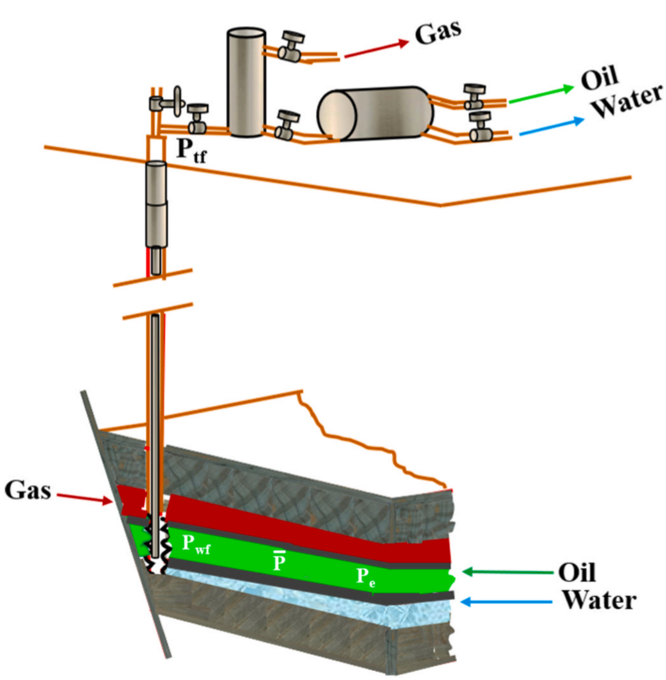

Fig. 1. Petroleum production system (Tillero et al., 2014).

Oil and gas production optimization has been discussed in the literature by various researchers. Outomuro (1995) demonstrated that the definition of the reservoir flow mechanism, optimized perforating schemes, enhanced carbonate stimulation, and improved completion designs all contributed to the success of a heavy oil field's production rate (Vazquez Outomuro, 1995). Wang (2003) thoroughly discussed and compared various optimization techniques, including nodal analysis and optimizing algorithms, that can be used in production (Wang, 2003). Pontiff et al. (2005) proposed a method called process optimization review for identifying opportunities to increase profitability while reducing greenhouse gases like methane in production operations (Pontiff and Boyer, 2005). Nasser et al. (2012) discussed how to use a statistical failure analysis method to analyse downhole pump performance in order to lengthen equipment lift time and reduce workover costs (Nasser et al., 2012). Shere et al. (2008) created an online production optimization tool that allowed users to download and run offline-models to further investigate well problems (Shere et al., 2008). Ashena et al. (2021) discussed how to improve production by optimizing completion and artificial lift: Simulations of 11 wells from an oilfield in the area were run using nodal and sensitivity analysis to find the best scenario and completion/production parameters (Ashena et al., 2021). Wellhead pressures, tubing dimensions, and water cuts are among the parameters that were optimized. Mahmud et al. (2017) used nodal analysis to investigate the performance of a gas well. Well level optimization was accomplished by adjusting the wellhead pressure, tubing size, and skin factor (Mahmud et al., 2017).

This proposed study aimed to contribute knowledge to gas field operators, oil and natural gas producers, academicians, and other researchers to ensure adequate and satisfactory information on the optimization of natural gas fields. It explored in detail the production optimization approach to extend the production plateau of a conceptual gas field. The optimization approach involved varying three production system constraints, which were, production system separator pressure, well tubing size, and the number of perforated layers or zones.

3. Conceptual gas field description

The conceptual gas field is an ideal model of dry gas field with an area assumed to be about 756 km^2.The field consist of 4 onshore production wells (PW-2, PW-3, PW-4, and PW-5) and one offshore production well (PW-1), all of which are producing. These five wells contain gas in the Miocene. The gas produced is transported to the gas processing facility (GPF). The average total distance of the network flowlines from the well PW-5 which is far from gas processing plant is 8.6 KM (Fig. 2). The flowlines from the wells PW-2, PW-3, and PW-4 to Gathering Station has an internal diameter (ID) of 6 inches. The flowline from the well PW-5 to Gathering Station has an ID of 16 inches. Furthermore, the flowline from the well PW-1 to Gathering Station has an ID of 6 inches. The flowline from Gathering Station to GPF has an ID of 16 inches. The flowline from GPF to gas processing plant has ID of 16 inches (Fig. 2). The total estimated gas field reserves are 1316.9 Bscf. Remaining economically recoverable gross 2 P sales natural gas is estimated at 423.3 Bcf.

This conceptual gas field consists four sand packages which are CF2 upper sand, CF2 lower sand, CF1 upper sand and CF1 lower sand. The CF2 upper sand package contains sands described as the F, G, H, and I sand while the CF2 lower sand package contains sands which have been described as the C, D, and E sands, all of Mio-Oligocene age. These two sand packages are separated by shale. The CF1 upper sand consists of K3, K2, K1, and K1A sands. The CF1 lower sand package consists of K0 sand. Fig. 3 illustrates the sand packages and perforated strata for each well.

The PW-1 well penetrates in G, D & E sands. Both sands packages

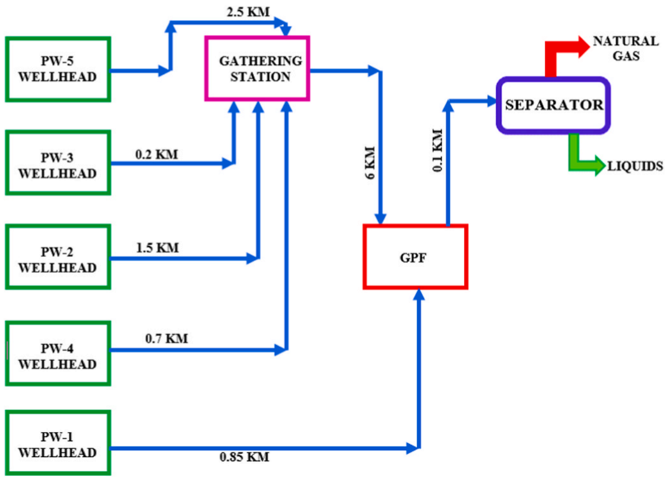

Fig. 2. Conceptual gas field surface networking system flow diagram.

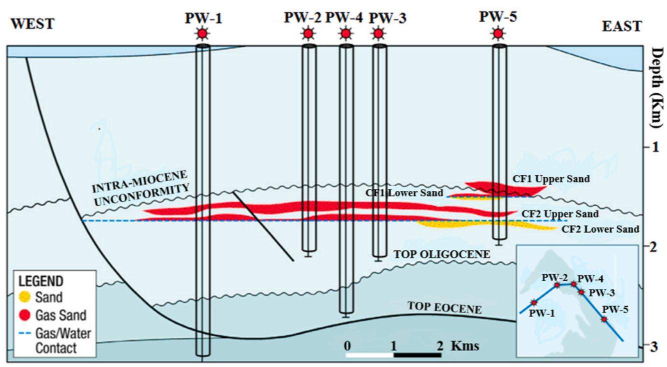

Fig. 3. Location of producing wells and sand intervals of conceptual gas field.

have been perforated, but only D & E sand is currently producing. The PW-2 well penetrates in F, G, I, C and D sands. The well is currently producing only from the F strata that is currently perforated. The PW-3 well penetrates F, G, C and D sands. But the well is perforated through G sand, which is currently producing. The PW-4 well penetrates H, D sands. H is currently producing. The PW-5 well penetrates F, K1, K2 and K3 sands. It is currently producing through the K2 sands.

As of July 2021, it was assumed that the average constant gas production rate at the conceptual gas field was 85 MMscfd. The gas demand outlook for that gas field was predicted to be in three phases. The first phase case was capped at 80 MMscfd starting July 1, 2018. The second phase case was capped at 105 MMscfd starting November 1, 2018, and the third phase case was capped at 130 MMscfd starting November 1, 2019. It was also assumed in the Gas Sales Agreement (GSA) between the gas supply company and the conceptual gas field producers that the gas production had to be from October 26, 2006 up to 2031, and had to increase over time to a constant maximum of 130 MMscfd for up to 17 years supply period. But, due to factors such as declining reservoir pressure, high constant rate production of natural gas at this gas field could still be uncertain and the production plateau could not be maintained until 2031. Therefore, it is important to explore various alternatives to extend the production plateau to the required agreement period by optimizing conceptual gas field production system constraints in the most economical way in order to meet present and future natural gas demand from this field.

4. Methodology

This chapter describes all the methods and procedures which helped to achieve the results of the study. The main objective of the study was to extend the natural gas production plateau of a conceptual gas field throughout the sales agreement period by optimizing production system constraints and proposing the production approach to be applied in order to meet the present and projected future gas demand. The specific objectives of the study were: (i) To determine the natural gas production plateau length of the current conceptual gas field production system. (ii) To develop approaches to extend the natural gas production plateau length by changing production system constraints. (iii) To select the optimum approach by performing cost analysis for the approaches developed. (iv) To compare the costs of the selected approach with the costs of compressors and drilling of new wells.

The nodal analysis method was selected for changing production system constraints. The method was applied with the help of Integrated Production Modelling (IPM), which was the collection of General Allocation Programme (GAP), Production Systems Performance analysis (PROSPER), and Material Balance (MBAL). The IPM was selected because it is easy to use in creating models with less runtime and a very understandable user interface. It also models the complete natural gas production system, including the reservoir, wells, and the surface network.

The data collected to create the conceptual gas field model of this study included fluid properties (Table 2) like water salinity, water to gas ratio, separator pressure, gas gravity, condensate to gas ratio, mole percent H_2S, mole percent CO_2, and mole percent N_2; Reservoir parameters (Table 1) like permeability, thickness, temperature, reservoir pressure, porosity values, and connate water saturations; as well as well completion data, which included dietz shape factor, wellbore radius, perforation interval, well depths (Table 3), tubing and casing diameters.

4.1. Procedures

The study was carried out mainly to extend the natural gas production plateau of the conceptual gas field by changing the production constraints using the nodal analysis method with the help of Integrated Production Modelling (IPM), then selecting the most optimum combination of production constraints. The node that was selected in the method was bottom hole. Fig. 4, indicates the locations of the most common used nodes.

All of the components upstream of the node comprise the inflow section, while the outflow section consists of all the components downstream of the node (Economides, 2013). The requirements of this method are: (1) Flow into the node must be equal to the flow out of the node and (2) only one pressure can exist at a node (Beggs, 2003; Leong and Ben Mahmud, 2019). The data shown in Figs. 2 and 3 and Tables 1 and 2 were specified in MBAL, PROSPER, and GAP, where all results were obtained after simulation and detailed analysis. Step-by-step details on how the method was used are given briefly in the following sections:

4.2. Determination of the current production plateau length

The gas production profile constrained at 130 MMscfd was simulated by using the Integrated Production Modelling (IPM) by employing the

Table 2
Conceptual gas field PVT fluid properties.

S/N	Parameters	Amount	Unit
1	Gas gravity	0.5661	sp. gravity
2	Condensate to gas ratio	0.06	STB/MMscf
3	Condensate gravity	24.00	API
4	Water to gas ratio	0.157	STB/MMscf
5	Water salinity	2000	ppm
6	Mole percent H_2S	0	percent
7	Mole percent CO_2	0.18	percent
8	Mole percent N_2	0.18	percent

Table 1
Conceptual gas field reservoir data.

S/N	Parameters	Reservoir Layers									
		C	D	E	F	G	H	I	K1	K2	K3
1	Thickness, ft	32.6	35.99	25.01	156	146	216	214	186	198	201
2	Porosity, %	0.22	0.2	0.2	0.25	0.26	0.286	0.2	0.2	0.25	0.2
3	Net pay, ft	21	25	17.5	90	64.5	80	85	70	75	75
4	Net to gross, fraction	0.57	0.69	0.7	0.58	0.44	0.17	0.19	0.14	0.14	0.12
5	Permeability, md	300	300	300	190.15	260.3	250	260	265	270	270
6	Connate water Saturation, fraction	0.47	0.47	0.47	0.24	0.41	0.31	0.32	0.37	0.37	0.37
7	Reservoir pressure, psi	2990	2990	2990	2990	2990	2990	2990	2990	2990	2990
8	Reservoir temperature, °*F*	210	210	210	210	210	210	210	210	210	210
9	Rock Compressibility,/psi	3.999e-6	3.999e-6	3.999e-6	3.999e-6	3.999e-6	3.999e-6	3.999e-6	3.999e-6	3.999e-6	3.999e-6

Table 3
Conceptual gas field wells.

Well Name	Total Depth (ft)	Tubing Measured Depth (ft)	Dietz shape factor	Wellbore radius (ft)	Perforation interval (ft)	Heat capacities	
						Oil	Gas
PW-1	8597	6165	31.6	0.354	17.5	0.53	0.51
PW-2	6400	5878	31.6	0.354	90	0.53	0.51
PW -3	7790	5639.11	31.6	0.354	17.5	0.53	0.51
PW-4	8597	5900	31.6	0.354	90	0.53	0.51
PW-5	6569	4832	31.6	0.354	17.5	0.53	0.51

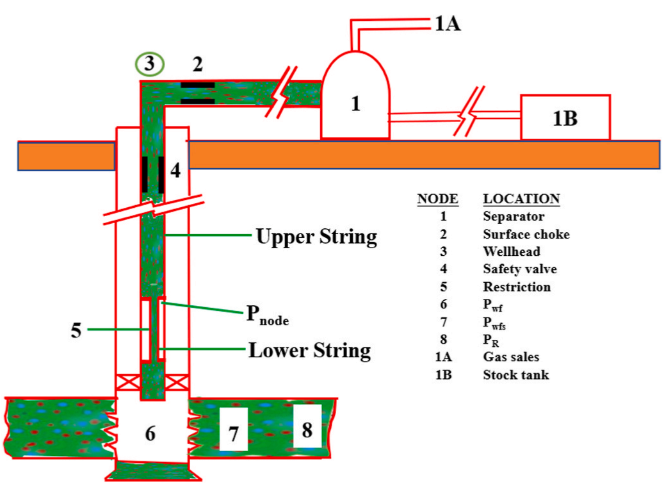

Fig. 4. Possible node locations (Leong and Ben Mahmud, 2019).

nodal analysis method. The guideline steps on how the simulation was performed are as follows:

4.2.1. Material balance (MBAL)

The MBAL was used to define the reservoir properties for modelling gas reservoir with material balance as the method used (IPM, 2010). It was assumed that each reservoir layer/zone to be treated as an independent reservoir for simplicity and that the zones do not communicate (IPM, 2010). The gas reservoir was considered volumetric with constant volume of closed gas reservoir and tank with no external energy support, such as absence of water influx (Ahmed et al., 2019). The elastic gas expansion force was the only driving mechanism for gas flow when the formation pressure decreases from P_i to P (equation 4-1) (Baker et al., 2015; Okotie and Ikporo, 2018; Lee and Wattenbarger, 1996; Hughes, 2010).

$$P_i \xrightarrow[t]{P_i \to P} G_p B_g$$

$$GB_{gi}\ (G - G_p) B_g \tag{4-1}$$

$$G = \frac{G_p B_g}{B_g - B_{gi}} \tag{4-2}$$

whereby:

$$B_g = \frac{P_{sc} ZT}{PT_{sc}} \tag{4-3}$$

$$\text{and } B_{gi} = \frac{P_{sc} Z_i T_i}{P_i T_{sc}} \tag{4-4}$$

$$G = \frac{G_p (P_i / Z_i)}{(P_i / Z_i) - (P/Z)} \tag{4-5}$$

$$\frac{P}{Z} = \frac{P_i}{Z_i}\left(1 - \frac{G_p}{G}\right) \tag{4-6}$$

whereby:

$$A_0 = P_i / Z_i \tag{4-7}$$

and

$$B_0 = \frac{P_i / Z_i}{G} \tag{4-8}$$

$$P / Z = A_0 - B_0 G_p \tag{4-9}$$

$$\therefore G = A_0 / B_0 \text{ and } G_R = \frac{a - \left(\frac{P}{Z}\right)_{\min}}{b} \tag{4-10}$$

4.2.2. Production Systems Performance analysis (PROSPER)

Then PROSPER was used to develop well deliverability curves using the pressure, volume, and temperature (PVT) and equipment data (Experts, 2010). The inflow performance relationship (IPR) and vertical lift performance (VLP) were developed by Petroleum experts-5 correlation (Experts, 2010). These performance curves were used to evaluate operating points for each well. Petroleum experts-5 correlation accounts for fluid density changes for incline and decline trajectories. It takes into consideration the varied liquid saturations near the well bore using the relative permeability curves to tune the permeability values and allows for a change in gas and condensate saturations near the wellbore using a multiphase pseudo pressure function (Experts, 2010). The Petroleum Experts IPR allows for the reduction in effective permeability resulting from liquid production in gas wells. The assumptions include no occurrence of condensate banking and the condensate that drops out is produced. It uses the Pseudopressure Quadratic equation for constructing IPR but use a modified non-Darcy D factor (Equation 4-11). Petroleum Experts model calculates flow profile considering transient conditions (Ahmad, 2016).

$$\Psi_R - \Psi_{wf} = a_2 Q_g + b_2 {Q_g}^2 \tag{4-11}$$

$$a_2 = \frac{1422}{kh}\left[ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right] \tag{4-12}$$

$$b_2 = \left(\frac{1422}{kh}\right)D \tag{4-13}$$

The term $(a_2 Q_g)$ account for the pseudopressure drop due to laminar flow while the term $(b_2 {Q_g}^2)$ represents pseudopressure drop due to turbulent flow effects.

$$\text{The inertial or turbulent flow factor}, D = A_1 \times A_2 \tag{4-14}$$

$$A_1 = \frac{3.161 \times 10^{-12} \beta T_{abs} SG}{\mu_g h_{perf}^2 r_w} \tag{4-15}$$

$$A_2 = \frac{k_{abs} h}{1637 T_{abs}} \tag{4-16}$$

$$k_{eff} = k_{abs}(1 - S_{wc})^2 \tag{4-17}$$

$$\beta = \frac{2.73 \times 10^{10}}{k_{eff}^{1.1045}} \tag{4-18}$$

The time that Petroleum Experts correlation takes into account is the flowing time as the last reservoir pressure equalize up to the analysis time. When the flowing time transcend T_{psss} (pseudo-steady state flow starting time), the deliverability calculation is done by means of T_{psss} that is correspondent to the pseudo steady state Darcy model (Ahmad, 2016).

Petroleum experts-5 correlation was selected due to its advanced capabilities in modelling any fluid type over any well or pipe trajectory (Production-Technology, 2017). Also, Petroleum Experts correlation use effective permeability based on the connate water saturation to calculate the β (turbulence)-factor. This factor results in high value for Petroleum Experts model that in return reduce the rate (Ahmad, 2016). For tubing flow, the general formula is simply expressed in equation 4-19.

$$Q_g = C_T\left(\frac{{\mathrm{P_{wf}}}^2}{\mathrm{e^s}} - {\mathrm{P_{wh}}}^2\right)^{0.5} \tag{4-19}$$

$$\mathrm{C_T} = \frac{\mathrm{T_{sc}}}{\mathrm{Z_{av}T_{av}P_{sc}}}\left(\frac{\pi^2 \mathrm{d^5 g_c} \sin\theta}{32\mathrm{f_f}}\right)^{0.5} \frac{\mathrm{e^{s/2}}}{(\mathrm{e^s} - 1)^{0.5}} \tag{4-20}$$

$$\mathrm{s} = \frac{-(2)(28.97)\gamma_g\left(\frac{g}{g_c}\right)\sin\theta\mathrm{L}}{\mathrm{Z_{av}T_{av}R}} \tag{4-21}$$

$$\text{For laminar flow fanning friction factor}, f_f = \frac{16}{N_{Re}} \tag{4-22}$$

For turbulent flow,

$$\frac{1}{\sqrt{f_f}} = -4\,log\left\{\frac{\varepsilon}{3.7065} - \frac{5.0452}{N_{Re}}log\left[\frac{\varepsilon^{1.1098}}{2.8257} + \left(\frac{7.149}{N_{Re}}\right)^{0.8981}\right]\right\} \tag{4-23}$$

4.2.3. General allocation program (GAP)

The General Allocation Program was used to create the production network for the conceptual gas field. Fig. 5 illustrates the production network created for the current production system (base case). This network comprised of the reservoirs, wells, wellheads, manifolds, and production separator.

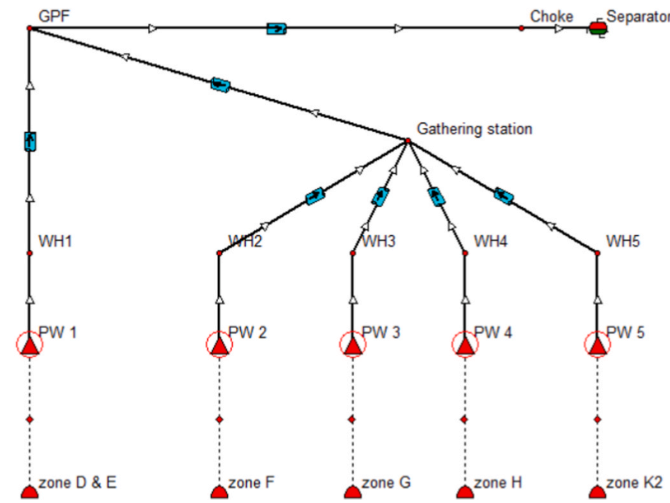

Fig. 5. Gap production network for gas field.

In GAP; data for pipelines, chokes and separator were specified. The Petroleum experts-5 correlation was selected for modelling the flow of natural gas in surface network for gathering lines and pipelines (Equation 4-24) (Economides, 2013). Then the network was solved to integrate the whole system.

$$Q_g = C_{PL}\left({P_{up}}^2 - {P_{dwn}}^2\right)^{0.5} \tag{4-24}$$

$$C_{PL} = \frac{T_{sc}}{P_{sc}}\left(\frac{\pi^2 d^5 g_c R \sin\theta}{1854.08\gamma_g f_f Z_{av} T_{av} L}\right)^{0.5} \tag{4-25}$$

The predictions were run to develop the natural gas production profile of the conceptual gas field model and then the model was constrained to the production rate of 130 MMscfd. The production plateau length obtained was used to determine the time for which the production constraints would have to be changed.

4.3. Approaches to extend the production plateau

The production constraints that were considered for adjustment were tubing sizes, separator pressures, and the number of perforations. The procedure for changing each selected production constraint is as follows:

4.3.1. Tubing size

The minimum value for the tubing size was assumed to be the current tubing size, which was 2.875 inches. The maximum value for the tubing size was selected from a range of possible tubing sizes that were limited by the smallest casing diameter of 7 inches. The possible tubing sizes were 3, 3.5, 4, 4.5, 5, 5.5, and 6.625 inches.

In the selection process of the maximum tubing size, individual simulations were run for each tubing size and criteria were set to filter the results. The procedure for simulation was the same as the one used in determining the production plateau in Section 4.2.1, except that the equipment data was varied, and thus, in each simulation, a new value of tubing size was an input to the PROSPER.

The criteria set were, first, its ability to extend the production plateau at a greater length than other sizes. Secondly, the incremental change in plateau length during upgrading the tubing size should be more than 1 year in order to reflect the cost value of selecting a greater consecutive tubing size, while the current tubing size could produce almost similar outputs. The tubing size that satisfied both criteria was taken as the maximum tubing size.

4.3.2. Separator pressure

Initially, the maximum value of the separator pressure was assumed to be the current separator pressure of 1450 psia. This pressure was lowered until the allowable minimum value was attained, which corresponded to the required delivery pressure in the gas processing plant, which was assumed to be 725 psia. The procedure for simulation was the same as the one used in determining production plateau in section 4.2.1 except that the value of separator pressure input to the GAP was varied in each simulation.

4.3.3. Number of perforations

Initially, the minimum value of the number of perforations was assumed to be the current number of perforations, which was one layer per well. Multilayer perforations on the existing wells were increased in order to improve the total gas production as per theory. This was done by perforating existing wells through the minimum number of reservoir layers (3 layers were increased) crossed by the wells necessary to extend the production plateau to the required point. Fig. 6 shows the added layers and respective wells.

The procedure for simulation was similar to the one used in determining production plateau in section 4.2.1 except those new perforations were created in GAP and corresponding well properties were created in PROSPER to define well performance through such layers.

4.4. Combination of the production constraints

Each production constraint brings its effect on production profile as well as a combination of the selected constraints may bring good result. Combination of production constraints have good sensitivity than individual constraint since it contributes on the bottom hole pressure hence drawdown pressure.

There are several possible combinations for changing natural gas production system constraints, but in this study eight (08) combinations were used in Table 4.

In evaluating the 8 combinations, maximum acceptable values for each variable were used in each combination. Then, each combination was simulated using the Integrated Production Modelling (IPM) by employing the nodal analysis method. The main result was the production plateau length for each of the combinations. The need for the analysis arisen in the selection of the best and most economic combination.

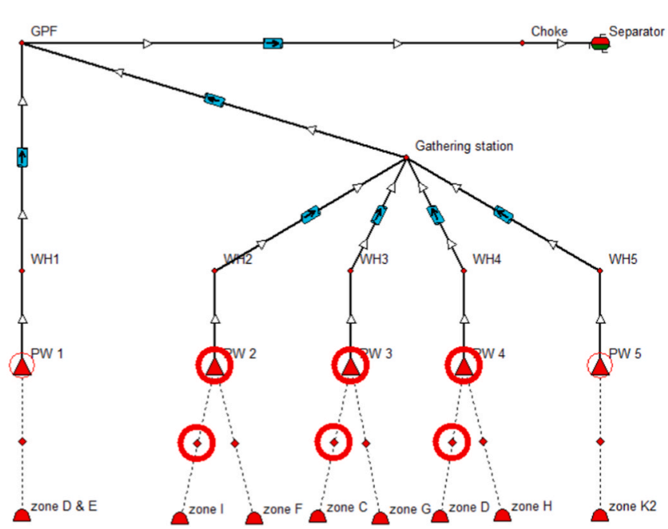

Fig. 6. Gap production network with added layers/zones for gas field.

Table 4
Simulation results for the combination cases developed showing different ways for changing production constraints.

Cases	Tubing size (inches)	Separator pressure (psia)	Number of perforations	Resulting plateau length (years)
01	2.875	725	5	4.4
02	2.875	725	8	9.5
03	2.875	1450	5	1.4
04	2.875	1450	8	2.1
05	4	725	5	9.3
06	4	725	8	16.2
07	4	1450	5	5.3
08	4	1450	8	8.7

4.5. Selection of the optimum approach

The possible combinations with their effect on simulated production plateau length required a cost analysis in order to select the best and most economic combination as the optimum production constraint. The most economic combination was the one that extended the production plateau until the end of the supply period of 2031 as per the agreement and resulted in the lowest cost compared to others.

There were various alternatives to extend the production plateau which all aimed to supply a maximum of 130 MMscfd for the whole supply period stipulated by the agreement. This means that if either of the alternatives was selected, it resulted to the same revenues earned. The only difference was in the costs of applying that alternative. Thus, it was acceptable to ignore revenues and compare costs only. The method used for cost analysis was the least cost analysis. The present values for buying equipments, installing equipments, downtime cost, operating costs, and maintenance costs were used to estimate the net present value of the costs as described in simplified form by equation (4-26) (Sabri et al., 2017).

$$NPC = PV_{ic} + TPV_{moc} \tag{4-26}$$

In equation 4-26, NPC refers to the net present value of costs, PV_{ic} is the present value of purchasing and installation of equipments, and downtime initial costs, and TPV_{moc} is the total present value of both operation and maintenance costs.

4.5.1. Compressor costs

The installation of the compressor was when the conceptual gas field production plateau started to decline. From the base case (Case 03), the production plateau only lasted for about 1.4 years so there were 14.6 years more to reach the desired date. The total cost of using the compressor option involved two main costs; purchasing and installation costs, and operation and maintenance costs.

In estimating the purchasing and installation costs, an "all-inclusive price" of united states dollars (USD) per installed horse power (hp) was used. This method was used due to the absence of vendor data. An "all-inclusive price" included material and equipment costs, labor costs, piping and valves costs, instrumentation and controls costs, and miscellaneous costs. The average "all-inclusive price" was estimated from 220 compressor stations in the United States of America. The compressor horsepower (hp) needed to produce natural gas at a gas flowrate of 130 MMscfd was calculated from compressor horsepower equation 4-27. The equation takes into account the compressibility of natural gas as follows (Hoopes et al., 2019; Brun and Kurz, 2018; Allison et al., 2019);

$$HP = 0.0857\left(\frac{\gamma}{\gamma-1}\right)QT_1\left(\frac{Z_1+Z_2}{2}\right)\left(\frac{1}{\eta_a}\right)\left[\frac{P_2^{\frac{\gamma}{\gamma-1}}}{P_1}-1\right] \tag{4-27}$$

In equation 4-27 HP is the compressor horsepower, Q is the gas flowrate, MMscfd (130 MMscfd), T_1 is the suction temperature of gas, ^{0}R (86 ^{0}R), P_1 is the suction pressure of gas, psia, P_2 is the discharge pressure of gas, psia, Z_1 is the gas compressibility factor at suction, dimensionless and Z_2 is the gas compressibility factor at discharge, dimensionless. And η_a is the compressor adiabatic (isentropic) efficiency, decimal value.

γ is known as the adiabatic or isentropic exponent for the gas or is the ratio of specific heats of gas, dimensionless. γ ranges from 1.2 to 1.4. For natural gas, 1.4 was selected for the use in the calculations. η_a is the compressor adiabatic (isentropic) efficiency, decimal value. The adiabatic efficiency, η_a generally ranges from 0.75 to 0.85. In the calculations, the average value (0.8) was used. The acceptable compression ratio for centrifugal compressors was 1.5 and the average gas compressibility factor was 0.85.

4.5.2. Drilling well costs

The least cost analysis method explained in section 4.5 was applied, and thus the minimum cost that would be incurred in the drilling of wells was when only one well is drilled.

4.5.3. Completion costs-case 06

This involved the costs of changing the tubing for all 5 wells and perforating 3 more zones (workover costs). Due to difficulties in obtaining the actual costs for well completion as they are unique for each well, average values were used with the assumption that the tubing set depth was 4,300 m.

4.6. Comparison of costs of selected approach with costs of compressor and drilling of wells

Minimum cost that incurred in drilling of wells was when only one well was drilled, thus it was assumed that only one well was drilled. It was also assumed that the year of compressor installation was the year when the production plateau for the current production system started to decline. The net present value of costs (NPC) for both compressor and drilling of one well were then calculated using equation (4-26). The resulting net present value of costs for compressor and for drilling a well were compared to the cost of the selected production constraints combination. Thus, the most economical method was selected on the basis of having the lowest net present value of costs.

5. Results and discussions

This section provides the results and their discussions. In section 5.1, the production profile is presented, and from it, the need to extend the production plateau is justified. Then, before getting into details with the simulation results in section 5.3 for changing the production constraints, the selected maximum tubing size is shown in section 5.2. From the simulation results, the best approach selected is shown in section 5.4.

5.1. The current production plateau length

The gas production profile of the conceptual gas field was simulated before any production constraints were varied, and resulted to a production plateau of 1 year and 5 months until March 1, 2017 as shown by base case (Case 03) (Fig. 7). This showed the need for extending the production plateau so as to ensure the longer production plateau period. Thus, the conceptual gas field production network was needed to be extended for about 14 years and 7 months.

But results from the base case simulation plot (Fig. 7) showed that the production period seemed to be short when the field was made to produce natural gas at a constant rate of 130 MMscfd from the beginning. To extend the production period of the gas field, a new simulation was performed and was constrained at different production periods which were assumed as production history. The results are given in modified production profile for base case plot (Fig. 7). In the first part of the graph, from October 1, 2015 to July 1, 2018, the gas production rate was simulated at an average rate of 45 MMscfd, which reflected the actual production history corresponding to the respective time interval.

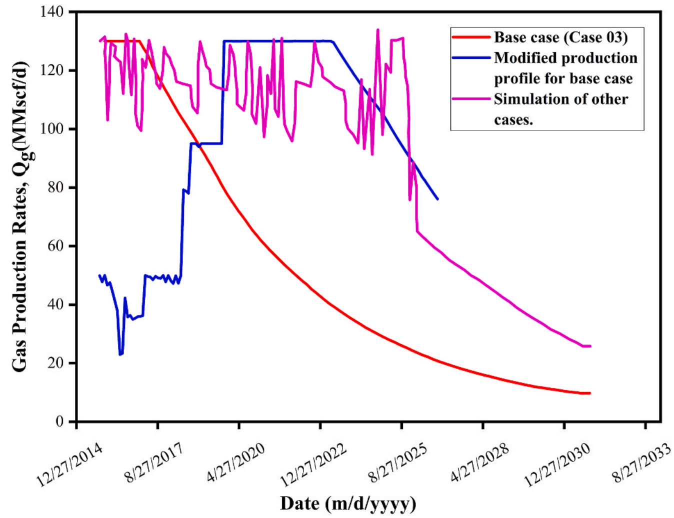

Fig. 7. Conceptual gas field production profile.

The second part of the graph, from July 1, 2018 to November 1, 2018, the gas production rate was simulated at a constant rate of 80 MMscfd to reflect the production history. The third part of the graph, from November 1, 2018 to November 1, 2019, the gas production rate was simulated at a constant rate of 95 MMscfd to reflect the actual production history. The fourth part of the graph, from November 1, 2019 to June 1, 2023, represents the production plateau of 130 MMscfd. The fifth part of the graph, further beyond June 1, 2023, represents the production decline. This simply means the production plateau was needed to be extended to October 1, 2031 (8 years) to ensure the consumer's demand.

This simulation methodology was not used to simulate the rest of the cases due to occurrence of spikes in the natural gas production plateau which were seen to increase as more parameters were varied to increase the plateau length. Fig. 7 on simulation of other cases plot illustrates the scenario felt during simulating other cases using the same methodology. The spikes can be seen throughout, in a way that even the production plateau cannot be seen.

5.2. Tubing size selection

Fig. 8 indicates the simulation results of various tubing sizes under 1450 psia and 725 psia separator pressures respectively. From the earlier

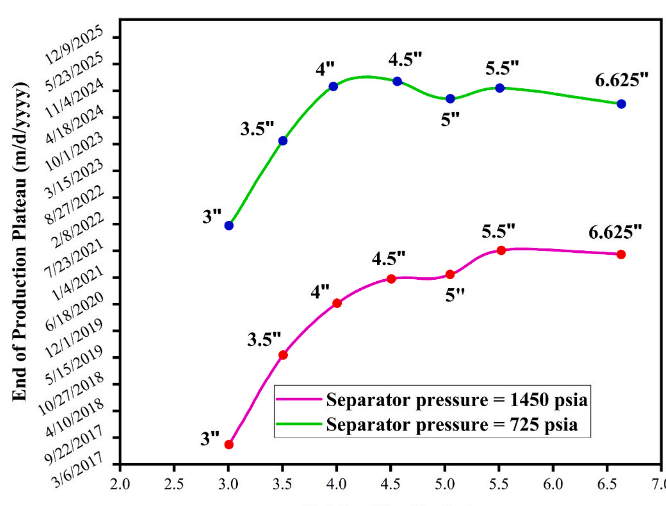

Fig. 8. Tubing size selection for separator pressure of 1450 psia and 725 psia.

parts of both plots, the gas production plateau length generally increased as the tubing diameter increased. The increase in the gas production plateau length was due to larger natural gas inflow that resulted from decrease in friction losses as tubing diameter increased (Lyons, 2009). In both plots, there was a diameter once reached, the production plateau did not increase any further. This diameter is known as critical diameter (Lyons, 2009). The critical diameter was 5.5 inches when the separator pressure of 1450 psia was used (Fig. 8). While with the separator pressure of 725 psia, the critical diameter was 5.5 inches (Fig. 8). Both critical diameters provided an upper limit to the maximum tubing size selection.

With tubing size of 5 inches and separator pressure of 1450 psia, there was a slight deviation from the general trend (Fig. 8). This might be attributed largely to the limitations of the simulator used. This led to a tubing size of 4.5 inches being the best selection on the basis of the second criteria set in Section 4.2.2. Similarly, the same criteria led to the selection of 4 inches as the best tubing size for a separator pressure of 725 psia. Finally, the tubing size of 4 inches was selected as the best maximum tubing size for both separator pressures based on the fact that it might produce almost similar outputs with 4.5 inches tubing as separator pressure declined (eventually) and that it was the economical choice (as tubing diameter increased, its price also increased).

5.3. Effects of changing production constraints on plateau length

The production constraints used in the simulation were minimum and maximum values. The separator pressures used were 725 psia and 1450 psia. But also, the tubing sizes used were 2.875 inches and 4 inches. The perforations were initially made in one zone per well, as seen in Fig. 5, and then three new zones were added, as shown in the conceptual gas field production network in Fig. 6. The results of the simulation for varying the production constraints are summarized in Table 4, Figs. 9–16, and Fig. 17.

5.4. Effect of changing the tubing size

One of the most important components in the production system is the tubing string. The effect of increasing tubing sizes can be seen in Figs. 18 and 19. Fig. 18 shows the effect of increasing tubing size on extending the natural gas production plateau before the increase of perforations in the production network. When the tubing size was increased from 2.875″ to 4” with the separator pressure adjusted to 1450 psia, the production plateau increased by 3.9 years, and when the

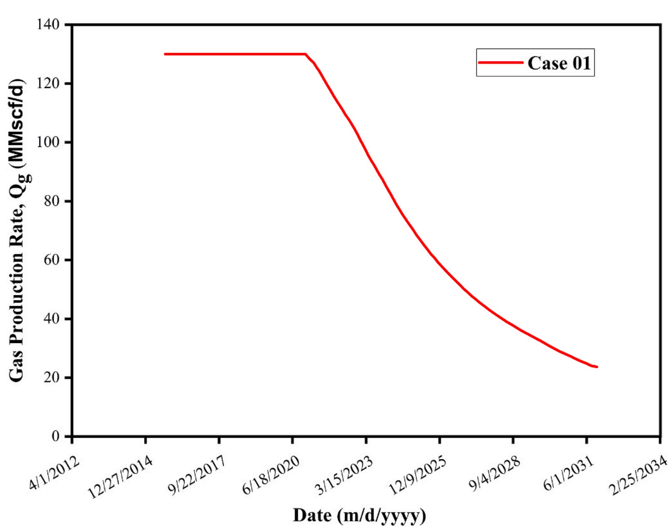

Fig. 9. Plateau length resulted from case 01 production constraints.

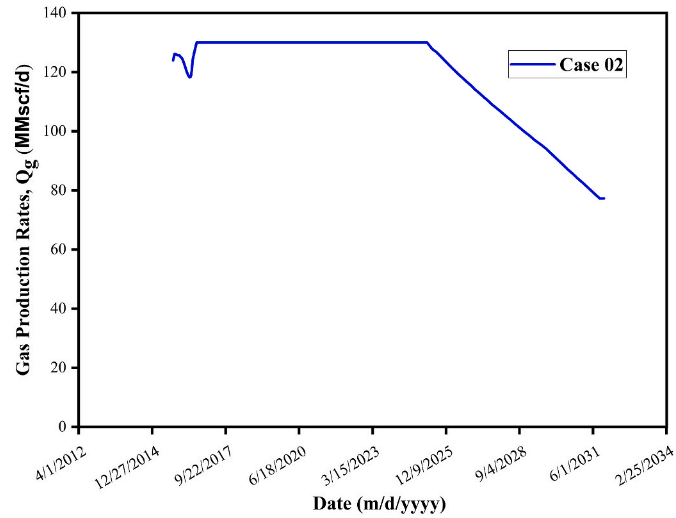

Fig. 10. Plateau length resulted from case 02 production constraints.

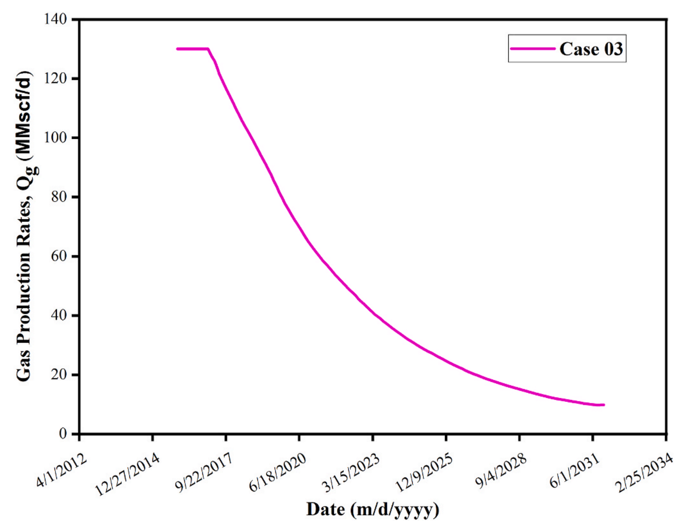

Fig. 11. Plateau length resulted from case 03 production constraints.

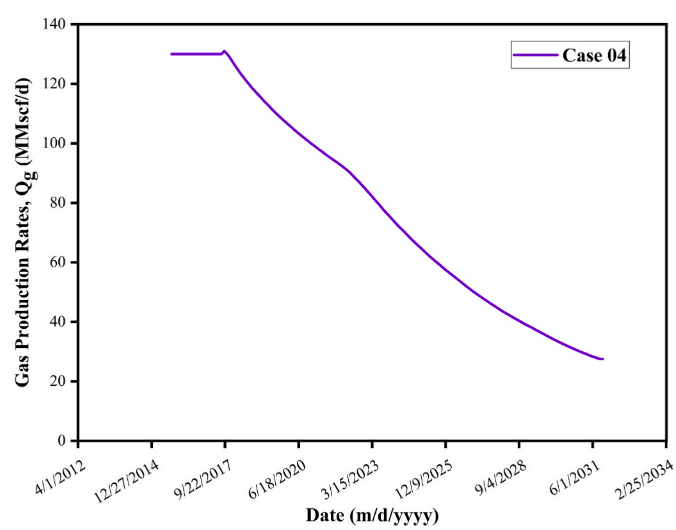

Fig. 12. Plateau length resulted from case 04 production constraints.

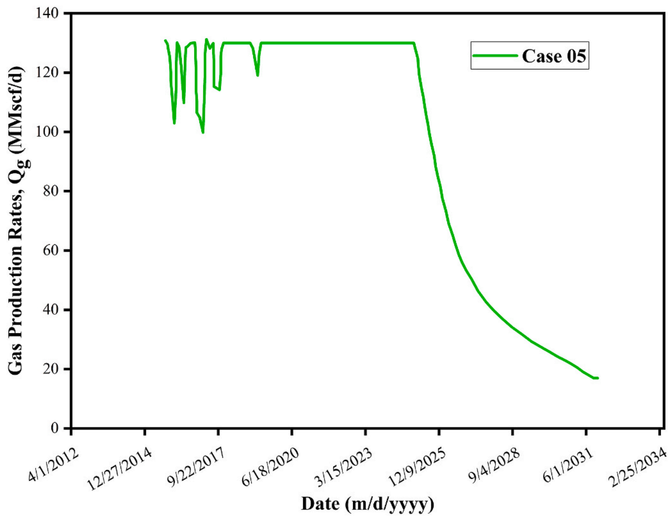

Fig. 13. Plateau length resulted from case 05 production constraints.

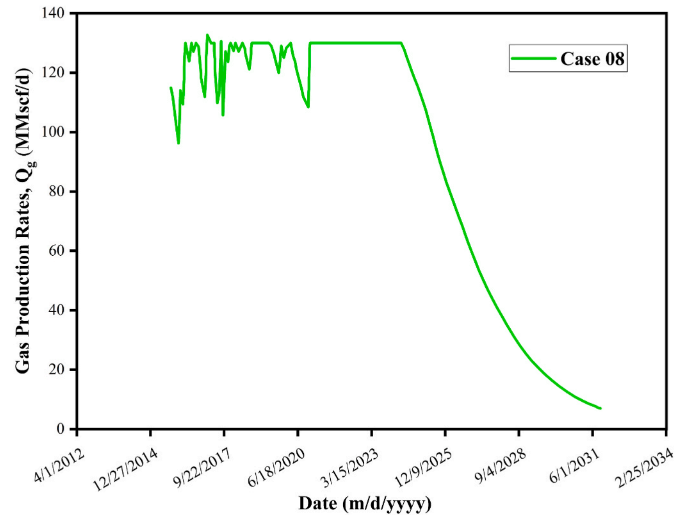

Fig. 16. Plateau length resulted from case 08 production constraints.

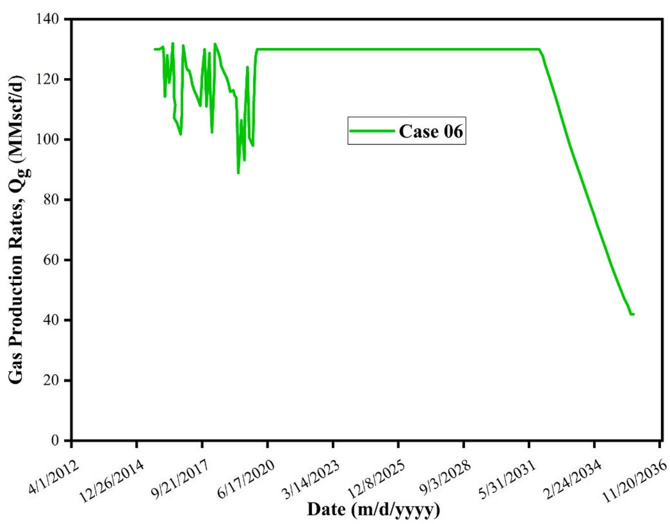

Fig. 14. Plateau length resulted from case 06 production constraints.

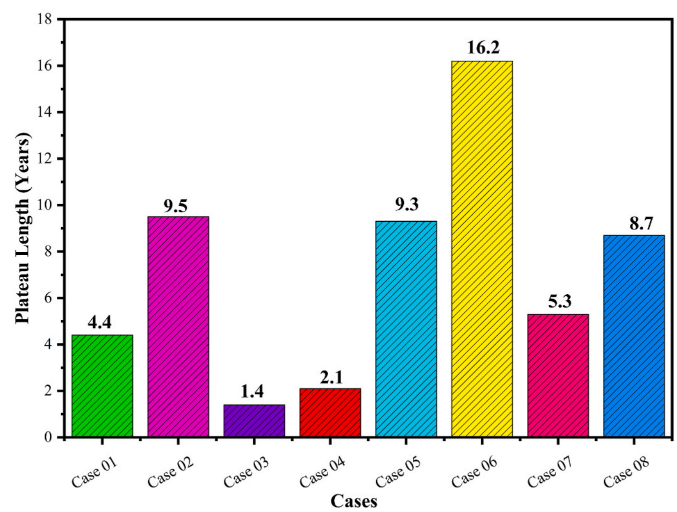

Fig. 17. Plateau length for the developed cases.

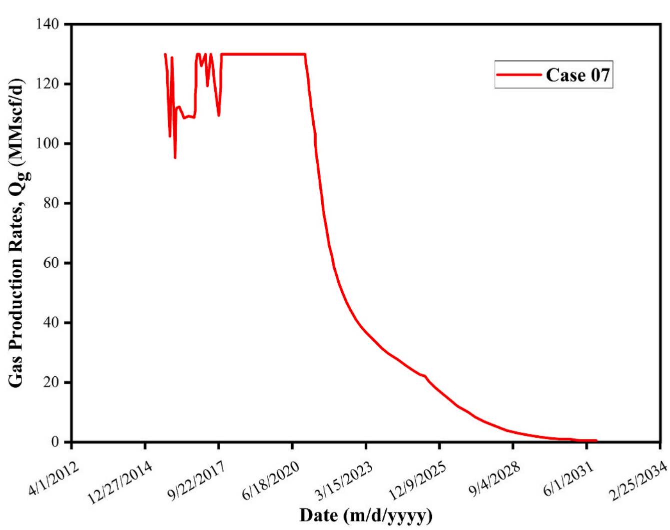

Fig. 15. Plateau length resulted from case 07 production constraints.

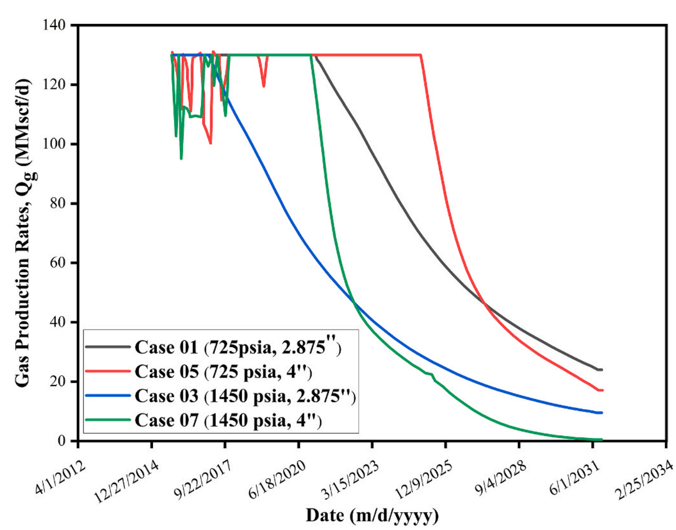

Fig. 18. Effect of tubing size and separator pressure before increasing perforations.

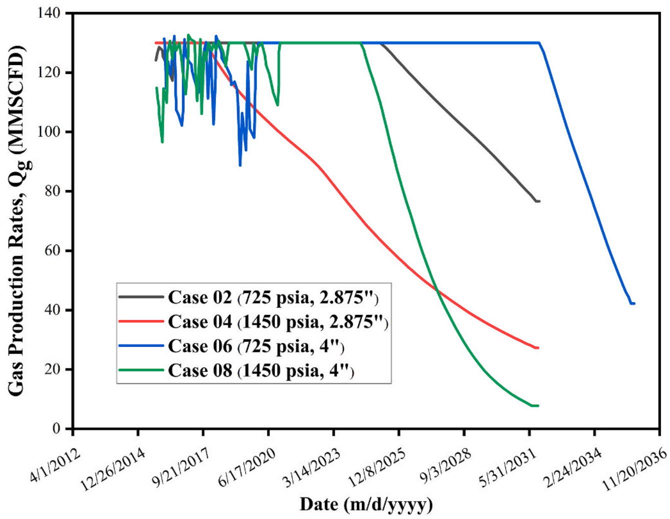

Fig. 19. Effect of tubing size and separator pressure after increasing perforations.

separator pressure was set to 725 psia, the production plateau increased by 4.9 years.

Fig. 19 indicates the effect of increasing tubing size on extending the natural gas production plateau after the increase of perforations in the production network. When the tubing size was increased from 2.875″ to 4” with the separator pressure adjusted to 1450 psia, the production plateau increased by 6.6 years, and when the separator pressure was set to 725 psia, the production plateau increased by 6.7 years.

Generally, in this study, the variation of the tubing size affected the tubing performance relationship (TPR), or simply the outflow curve. Similarly, the producing capacity of the production system was affected (Beggs, 2003). As the diameter of the tubing increased, the friction losses decreased, which resulted in a lower bottom hole flowing pressure (P_{wf}) and, therefore, a larger inflow (Lyons, 2009). Therefore, the findings from this study indicated that with maximum perforations, the effect of increasing tubing size was the same regardless of the separator pressures because production length was extended by almost 6.65 years at both 1450 psia and 725 psia pressures. This might be inferred as the maximum system production capacity had been attained. Thus, further improvement of gas production system constraints had less impact on increasing system capacity.

5.5. Effect of changing the separator pressure

The effect of lowering separator pressure before zones were added to the natural gas production network can be seen in Fig. 18. The plot indicates that when the separator pressure was lowered from 1450 psia to 725 psia with the tubing size set to 2.875″, the effect of extending the production plateau increased by 3 years. While lowering the separator pressure from 1450 psi to 725 psi with the tubing size set to 4”, this resulted in a 4-year extension of the production plateau.

Similarly, the effect of lowering separator pressure after zones were added to the natural gas production network can be seen in Fig. 19. The plot illustrates that when the separator pressure was lowered from 1450 psia to 725 psia and the tubing size was set to 2.875″, the effect of extending the production plateau was increased by 7.4 years. While the separator pressure was lowered from 1450 psia to 725 psia and the tubing size set to 4”, the effect of extending the production plateau was increased by 7.5 years.

According to the findings, lowering separator pressure increased the capacity of the natural gas production system. This effect was on the outflow performance of the production system. It also should be noted that, the separator pressure should not be lowered below the minimum delivery pressure of the pipeline unless a compressor is scheduled to be used later (Beggs, 2003).

It also seemed that with maximum perforations, lowering separator pressure had similar effects of increasing the production plateau regardless of the tubing size, because the production plateau length increased by almost 7.45 years with both 2.875″ and 4” tubing. This might be inferred as the maximum system production capacity being attained. Thus, further improvement of production constraints had less impact on increasing the capacity of the natural gas production system.

5.6. Effects of increasing the perforated zones

Three new reservoir layers or zones were added (zone I, zone C, and zone D). Figs. 18 and 19 both illustrate the effect, which is further summarized in Table 5 and Fig. 20. According to these findings, perforating more layers or zones had the effect of increasing the capacity of the gas production system.

5.7. Selection of the optimum approach

The simulation began on October 1, 2015 and ended on October 1, 2031. Therefore, a plateau of 16 years' length was necessary. There were two criteria for selecting the optimum approach: first, the approach should extend the natural gas production plateau until 2031; and second, it should result in the lowest cost compared to other approaches that satisfy the first criteria.

The only case that satisfied the first criteria was case 06 (4-inch tubing, 725 psia separator pressure, and 8 perforations). So, there was no necessity for performing a cost comparison. This was the optimum production constraint combination that extended the production plateau to the required date.

5.8. Cost comparison of the selected approach with the costs of compressors and of drilling wells

The costs for each option were discussed separately in each subsection, starting with compressor costs, then costs for drilling a well, and finally completion costs. Then, a summary for cost comparison was provided at the end, after the costs for each option were determined.

5.8.1. Compressor costs

The average "all-inclusive price," estimated from 220 compressor stations, was found to be $1,712/hp (Zhao and Rui, 2014). From the desired conditions for compression, it was found that the necessary compressor horsepower was 438 hp. This resulted in a $749,856 purchasing and installation cost. The maintenance and operating costs per year were taken as 5% of the average purchasing and installation cost per hp (Zhao and Rui, 2014). Thus, for 14.6 years, it was $547,394.88. Therefore, the resulting total compressor cost was $1,297,250.88.

5.8.2. Drilling well costs

The average drilling cost for a vertical well was $30,000,000, the annual well maintenance cost was $1,100,000, and the annual well operation cost was $400,000 (Weatherill, 2016). Thus, the 14.6 years required to extend the production plateau resulted in a discount factor of

Table 5
Effect of adding reservoir layers/zones.

Conditions	2.875″, 725 psia	2.875″, 1450 psia	4″, 725 psia	4″, 1450 psia
Before adding zones (years)	4.4	1.4	9.3	5.3
After adding zones (years)	9.5	2.1	16.2	8.7
Net effect (years)	5.1	0.7	6.9	3.4

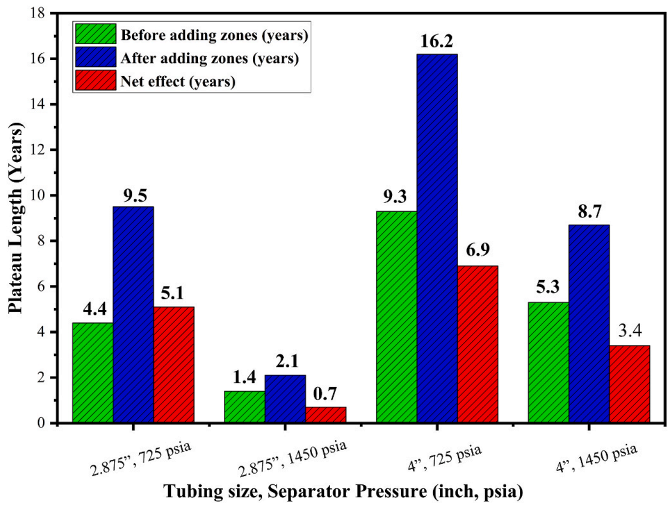

Fig. 20. Effect of adding reservoir layers/zones.

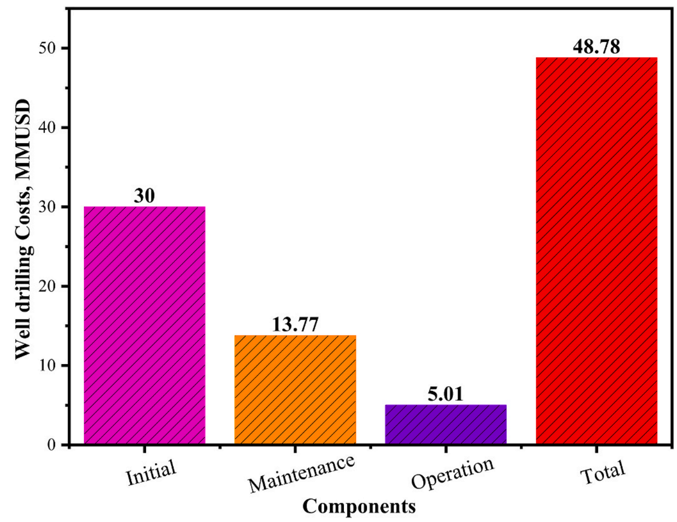

Fig. 21. Present value for well drilling costs of conceptual gas field.

12.517, with a 3.2% inflation factor (Economics, 2021). The total present value of the costs was $48,780,000, as shown in Table 6 and Fig. 21.

5.8.3. Completion costs-case 06

The total cost of changing the tubing for all 5 wells and perforating 3 more zones (workover costs) was $855,600, as shown in Table 7 and Fig. 22 (NLFISHER, 2015).

Completion costs for conceptual gas field (NLFISHER, 2015).

5.8.4. Summary of the cost comparison

Therefore, of the total costs from each option, the lowest one was for the completion of Case 06 ($855,600), as can be seen in Fig. 23. This option was cheaper by 34.05% than the compressor usage option and by 98.25% than the drilling of a well.

6. Conclusions

In this study, optimization of natural gas production system constraints to extend the production plateau of the conceptual gas field was studied by nodal and least cost analysis methods. The current production plateau of the field was also simulated to get an overview of the number of production years that needed to be extended so as to align with the gas sales contract signed. Various gas production system constraints combination cases were simulated to get a better understanding of how varying separator pressures, tubing sizes, and perforation constraints would influence the natural gas production plateau of the conceptual gas field. The effectiveness of a combination of all three constraints in terms of production plateau was also investigated, which assisted in the selection of the optimum approach after comparison with the costs of compressor installation and drilling of wells. Therefore, from the study, the following conclusions can be drawn:

(i). The simulation began on October 1, 2015 and ended on October 1, 2031. Therefore, the 16-year plateau in natural gas production was necessary.

Table 6
Present value for well drilling costs of conceptual gas field.

Component	Present value costs, MMUSD
Initial drilling	30
Maintenance	13.77
Operation	5.01
Total	48.78

Table 7
Completion costs for conceptual gas field (NLFISHER, 2015).

Component	Price/unit, USD	Total cost, USD
Tubing & Accessories	137,600 (times 5)	688,000
Perforating	25,500 (times 3)	76,500
Equipment Rentals	18,700	18,700
Inspection/Safety	15,000	15,000
Wellsite supervision	17,400	17,400
Miscellaneous costs	40,000	40,000
Total		855,600

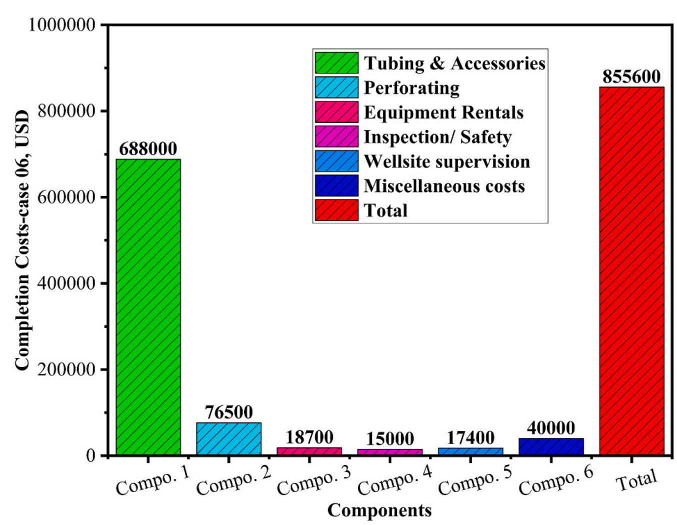

Fig. 22. Completion costs for conceptual gas field.

(ii). The natural gas production plateau of the conceptual gas field was found to have started declining on March 1, 2017, when the production system was constrained to 130 MMscfd. However, with modifications to the constraints to elongate the production period, the results showed that the production plateau would start to decline on June 1, 2023.

(iii). The criteria for selecting the optimum approach were its ability to extend the production plateau over a longer period of time and having the lowest cost compared to other approaches.

(iv). Among eight possible gas production constraints combinations of varying separator pressures, tubing sizes, and number of layers

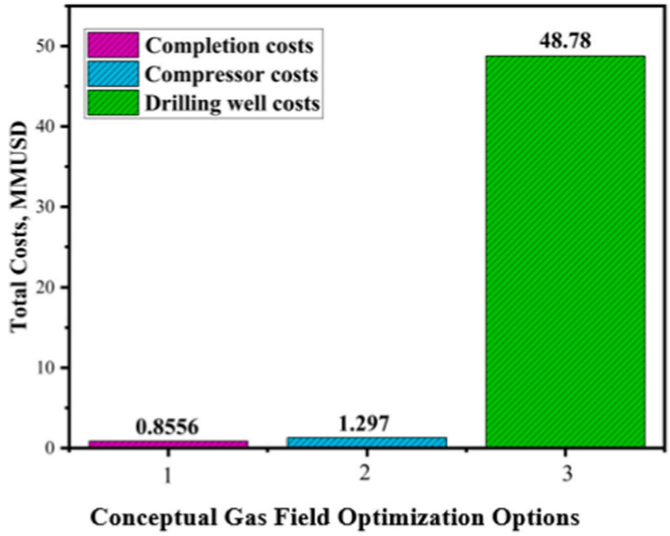

Fig. 23. Cost comparison of the completion of case 06 with the costs of a compressor and drilling a well.

perforated, the best combination was to lower the separator pressure to 725 psia, increase the tubing size to 4″, and perforate three more zones (zone I, zone C, and zone D).

(v). The production constraints combination case 06 (4-inch tubing, 725 psia separator pressure, and 8 perforations) was the only combination that extended the production plateau at a longer period until October 1, 2031.

(vi). This case 06 combination was found to be cheaper by 34.05% than the compressor usage option and by 98.25% than the drilling of a well option.

(vii). As a result, this study was able to cover a wide range of important aspects of natural gas production optimization in the conceptual gas field, as well as its impact on extending the stable period of production. As a result, the study advises gas field operators to adopt this combined constraint approach as a means of extending the natural gas production plateau.

(viii). Finally, the study discovered the following general concern about the optimization of natural gas field production system constraints: lowering separator pressure, increasing tubing size, and perforating more zones may extend the gas production plateau of a gas field to the required period. Therefore, this research may have a considerable impact on the oil and natural gas production industry.

Credit author statement

Elia Wilinasi Sikanyika: Conceptualization, Methodology, Writing – original draft; **Wu Zhengbin**: Supervision.**Husham Elbaloula**: Writing – review & editing; **Maurice Oscar Afiakinye**: Investigation and Writing – original draft; **Armel Prosley Mabiala**: Writing – original draft and editing; **Shu Jiang**: Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

The data used is specified within the manuscript

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Appendix

Nomenclature.

Roman symbols	Meaning
A	Cross–sectional area of choke or restriction in in^2
B_g	Formation volume factor of gas in ft^3/SCF
B_{gi}	Initial formation volume factor of gas in ft^3/SCF
C	Stabilized performance coefficient, Mcf/D/(1000 psia^2)^n
C_{PL}	Pipeline coefficient in $(Jm^5mol^{-1}s^{-1})^{0.5}$
C_T	Tubing coefficient in $m^5/N\,\mathrm{sec}^{0.5}$
d	Inside diameter of pipe in ft
D	Darcy factor in $(STB/D)^{-1}$
E	Pipeline efficiency in fraction
f	Friction factor, dimensionless
f_f	Fanning friction factor, dimensionless
g	Acceleration due to gravity in ft/sec
g_c	Gravitational constant, Nm^2/kg^2
G	Initial gas in place in SCF
G_p	Cumulative production in STB
G_R	Initial gas in place of the reservoir in SCF
h_{perf}	Perforation interval in ft
H	Vertical depth in ft
k	Permeability in md
k_{abs}	Absolute permeability in md
k_{eff}	Effective permeability in md
L	Pipe length in mi
n	Numerical exponent, dimensionless
N_{Re}	Reynolds number, dimensionless

(*continued on next page*)

(*continued*)

Roman symbols	Meaning
P_i	Initial formation pressure in psia
P	Final formation pressure in psia
P_1	Suction pressure of gas in psia.
P_2	Discharge pressure of gas in psia.
P_b	Base pressure in psia
P_d	Downstream pressure in psia
P_{dwn}	Downstream pressure in psia
P_{node}	Node pressure in psia
P_R	Shut-in reservoir pressure in psia
P_{sc}	Pressure in psia at standard conditions
P_{up}	Upstream pressure in psia
P_{wf}	Flowing bottom hole pressure in psia
P_{wfs}	Flowing sand face pressure in psia
P_{wh}	Wellhead flowing pressure in psia
Q or Q_g	Gas flowrate in Mscf/d
r_e	External boundary radius in ft
r_w	Wellbore radius in ft
R	Universal gas constant in 10.73 $psi\, ft^3/lb - mole{-}^0R$
e	Relative roughness in in
S	Absolute pipe roughness ≈0.0006 in
t	Time in sec
$\overline{T}$	Average temperature in ^{0}R
T_1	Suction temperature of gas, ^{0}R
T_{abs}	Absolute temperature in ^{0}R
T_{av}	Average temperature in ^{0}R
T_b	Base temperature in ^{0}R
T_i	Initial temperature in ^{0}R
T_{psss}	Pseudo-steady state flow starting time in sec
T_{sc}	Temperature in ^{0}R at standard conditions
T_u	Upstream temperature in ^{0}R
Z	Gas deviation factor, dimensionless
$\overline{Z}$	Average gas compressibility factor in/psi
Z_1	Gas compressibility factor at suction, dimensionless
Z_2	Gas compressibility factor at discharge, dimensionless
Z_{av}	Average compressibility in/psi
Z_i	Initial gas deviation factor, dimensionless

Greek letters	Meaning
ε	Relative pipe roughness, dimensionless
β	Turbulence -factor.
Ψ_R	Pseudo reservoir pressure in psia
Ψ_{wf}	Pseudo bottomhole flowing pressure in psia
μ_g	Gas viscosity in cP
γ	Ratio of specific heats of gas, dimensionless.
γ_g	Gas specific gravity, dimensionless
η_a	Compressor adiabatic (isentropic) efficiency

Abbreviation	Longform
Bcf	Billion Cubic Feet
GPF	Gas Processing Facility
GAP	General Allocation Program
GSA	Gas Sales Agreement
HP	Compressor horsepower
IPM	Integrated Production Modelling
IPR	Inflow Performance Relationship
MBAL	Material Balance
MMscfd	Million Standard Cubic Feet per Day
MMUSD	Million United States Dollars
NPV	Net Present Value
NPC	Net present value of costs
PROSPER	Production Systems Performance analysis
PV_{ic}	Present value of purchasing and installation of equipments, and downtime initial costs
PVT	Pressure, Volume, & Temperature
PW-1	Production Well 1
PW -2	Production Well 2
PW -3	Production Well 3
PW -4	Production Well 4
TPR	Tubing Performance Relationship
TPV_{moc}	Total present value of both operation and maintenance costs
VLP	Vertical Lift Performance
WH	Wellhead

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