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Numerical approach on production optimization of high water-cut well via advanced completion management using flow control valves

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Abstract

With the development of smart downhole control devices, such as the electric flow control valve (FCV), research on completion optimization using FCV control is gaining traction for successful field production management. Applying and verifying its applicability to actual assets with uncertain production issues occur are important. This study focuses on managing downhole devices to optimize fluid production in an actual onshore oil field in Alberta, Canada. The target field has been in production operation for over 20 years, and water flooding was used in the early stages of production to maintain reservoir pressure. However, according to the flow characteristics of the field, water injection caused a high water-cut issue due to water channeling. To mitigate the problem, proactive and reactive strategies were investigated to optimize FCV control. Additionally, the effect of completion optimization was estimated considering both the field-level economic value and the fluid production behavior at the device level. In most optimization cases, the cumulative water production could be reduced compared with the base case without valve control. Notably, the flow-balancing strategy increased the revenue of the target field by approximately 23 MM$ by maximizing oil production and suppressing water production. However, reactive and streamline-balancing strategies, which directly control and delay water production, undermined the economic value due to the decrease in oil production. The findings imply that FCV control strategy of suppressing only water production for the field with high water-cut could not be the optimal solution considering the reduction in oil production and the field's revenue. The results of this study could be used as a reference to optimize downhole devices when applying water flooding in fields where high water-cut is expected.

Keywords Flow control valve · Completion optimization · Field management · Water flooding

List of symbols

Latin letters

BF	Balancing factor for zonal production rate
C_g	Gas processing cost
C_w	Water processing cost
n	Number of flow control valves
NCF	Net cash flow
NPV	Net present value
Q_g	Surface gas production rate at flow control valve
Q_o	Surface oil production rate at flow control valve
Q_{res}	Calculated zonal production phase flow rate
Q^t_{res}	Target zonal production phase flow rate
Q_w	Surface water production rate at flow control valve
PV	Present value
R	Discount rate
s	Distance along the streamline corresponding to the coordinate
v	Flow velocity
WF	Weighting factor for flow control valve
x	Vector of flow control valve settings

Greek letters

ζ	Coordinate along a streamline
τ	Time of flight

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Acronyms

ACO	Advanced completion optimization
Cum.	Cumulative
FCV	Flow control valve
NPV	Net present value
OPR	Oil production rate
TOF	Time of flight
WPR	Water production rate

Introduction

Field development strategy significantly impacts the recovery factor of oil-in-place volume. This concept incorporates hundreds of decisions to obtain economic success pertaining to various influential factors, such as the number of production and injection wells, field production rates, well operating conditions, and the location of the wells. After a primary recovery period based on natural reservoir pressure, the strategies for secondary recovery, such as water injection, are also important to enhance recovery. For the secondary scheme, the operational conditions of production wells have a significant influence on the recovery factor because high water-cut by water injection can reduce the overall economic indicators of the field that has been previously abandoned and can aggravate environmental issues. Particularly, both preliminary and instantaneous studies are necessary to prevent the water channeling problem, causing the sweep efficiency to decrease. Therefore, optimizing well operations such as opening and/or closing well and adjusting the flow control valves for successful field management is important.

Recent studies on smart field management aim to optimize not only at the well level but also at the device or completion level within the same well (Ahmed et al. 2018, 2019; Tahir et al. 2019). This detailed optimization is a key element of the digital oil field that controls in-situ equipment, for example, the flow control valve (FCV), by remotely monitoring and analyzing the well conditions in real time (Chai et al. 2014). Furthermore, passive FCVs allow the same production rate for each zone, while active valves can be remotely controlled to optimize a production plan (Grebenkin and Davies 2012). When optimizing many variables related to FCVs, complex and nonlinear problems are encountered.

However, if numerous downhole devices are optimized over several decades of the production period, reservoir simulation that can provide basic data for the field development plan is extremely costly (Grebenkin and Davies 2012). For example, more than 70,000 variables were optimized in the Olympus benchmark challenge: 18 wells during 20 years with an interval of 3 months (Fonseca et al. 2018). Therefore, a computationally efficient algorithm is necessary for efficient device-level smart management. In the study conducted by Ahmed et al. (2019), 240 variables in total, 8 wells with three FCVs during 5 years with an interval of every 6 months, were optimized by local optimization based on a flexible control strategy (See Sect. "Description of reservoir modeling"). They emphasized the importance of optimization cost for the high-frequency operation of the FCV. Particularly, they used 100 reservoir models, considering uncertainty in the geological model and the exceedingly large number of reservoir simulations required for global optimization methods. If there are m variables for each time step and n optimization time steps, then the global (or long-term) optimization has $m \times n$ variables. In this case, a full reservoir simulation is required for each iteration. However, local (or short-term) optimization considers only m variables during a single simulation time step. Therefore, it requires only a single reservoir simulation. Hence, local optimization is advantageous to the efficiency in terms of the number of reservoir simulations with multiple control actions and flow constraints in each time step (Ahmed et al. 2019; Al-Aghbari et al. 2022; Litvak et al. 2011; Wang and Litvak 2008). Although it does not guarantee the global optimum, superior results were obtained compared with those of the non-optimization case (Ahmed et al. 2019). Particularly, local optimization is suitable for smart well optimization, and well rate allocation because of its efficiency. In addition to the local optimization of FCVs in well management, it is also applied to gas lifting optimization (Jeong et al. 2021).

Previous studies have proposed efficient optimization methods for FCV control (Ahmed et al. 2019; Barghouti et al. 2021; Chan et al. 2014; Dossary et al. 2012; Erlandsen 2000; Glandt 2005; Huang et al. 2011; Mubarak et al. 2008). Although a few studies applied FCV to an actual field, most of the previous studies aimed to verify the optimization methodology on simulated field cases. Presenting the application guidelines through a detailed analysis of actual field data considering production issues is necessary. This study's target field, an onshore oil field in Alberta, Canada, has produced oil with water flooding operations to support reservoir pressure. However, it demonstrates extremely high water-cut because of unexpected connectivity between the production and injection wells owing to high heterogeneity (See Sect. "Description of the target field"). We focused on the economic evaluation of the effectiveness of downhole device management in the Canadian onshore field. In addition, the effects of the FCV optimization were analyzed in detail based on the fluid production behavior from the field level to the device level. The simulation results obtained for the various completion optimization strategies were compared to suggest a suitable strategy for the target field with the risk of high water production.

The remainder of this paper is structured as follows: In the methodology section, the current state of the target field is reviewed, including the settings of FCVs; furthermore, the optimization strategies to be applied are discussed. In the result section, the effect of advanced completion optimization is demonstrated, and the simulation results according to the optimization strategies are compared. For all cases, the net present value (NPV) is considered to indicate the best practice for the target field.

Methodology

Description of the target field

The target field, an onshore oil reservoir in Alberta, was developed in 1971, and water flooding was conducted to maintain the reservoir pressure after 1975. It continues to produce oil, but it exhibits an extremely high water cut. Figure 1 depicts a typical example of the production history of the producer from February 1975 to March 2018. The cumulative water production increases relative to the nearly converging cumulative oil production with more than 90% water cut.

The original development plan was implemented; accordingly, the water injection wells were located in the southeast with a relatively deep reservoir depth, and some production wells were converted into injection wells. However, the field economy is still weak owing to high water cuts. Therefore, to restrain water production, completion optimization is considered.

In this study, it is assumed that FCVs are installed for each production well in the sector area of the field, and we optimized their openings to maximize NPV. Through this, using downhole devices, we intend to understand whether economic improvement is significant in small and medium-sized Canadian onshore fields; furthermore, we investigate the suitable optimization strategy for controlling smart valves. Additionally, we test the state-of-the-art optimization technique for the target field to reduce the simulation cost.

Description of reservoir modeling

Seismic data of the target field was not available to determine the minimum grid size in the horizontal direction. Without seismic data, finer-scale models cannot represent the heterogeneity of reservoir properties. Therefore, the number of grids in the X, Y, and Z directions were 17, 17, and 35, respectively, and the size of each grid was 100 m × 100 m × 0.7 m, considering the computing resources. In the case of reservoir simulation where complex multiphase fluid behavior occurs, such as enhanced oil recovery simulation, grid size should be much finer to capture characteristics of sweep efficiency (Sabirov et al. 2020). However, for water flooding without the use of chemicals (similar to this study), less refined grid systems would be sufficient (Chen et al. 2010; Christie 1996; Horritt and Bates 2001).

Figure 2 shows the distribution of porosity and permeability with the location of wells. The four production wells are located in the northwest of the field, and the single water injection well is located in the southeast of the relatively deep deposit. The means of the porosity and permeability models are 6.9% and 848.6 md, but the permeability is highly heterogeneous, with a large standard deviation of 3034 md. The horizontal permeability was assumed to be isotropic in the X and Y directions, and the vertical permeability was set to 10% of the horizontal permeability. In the case of the porosity model, a machine learning-based pseudo-density log was generated from the sonic log, and the 12 pseudo-density logs were employed on hard data (Kim et al. 2020). The reservoir property modeling described above was performed using E&P Software Platform Petrel (Schlumberger 2020a, b).

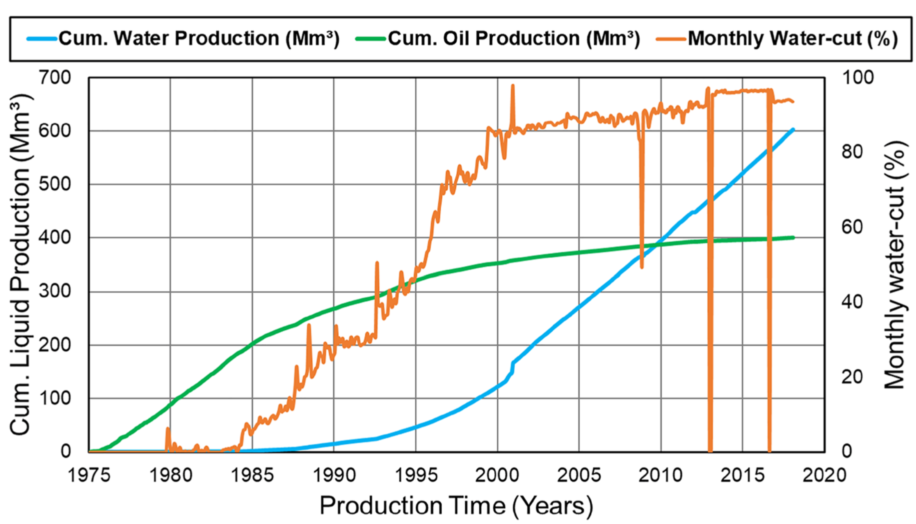
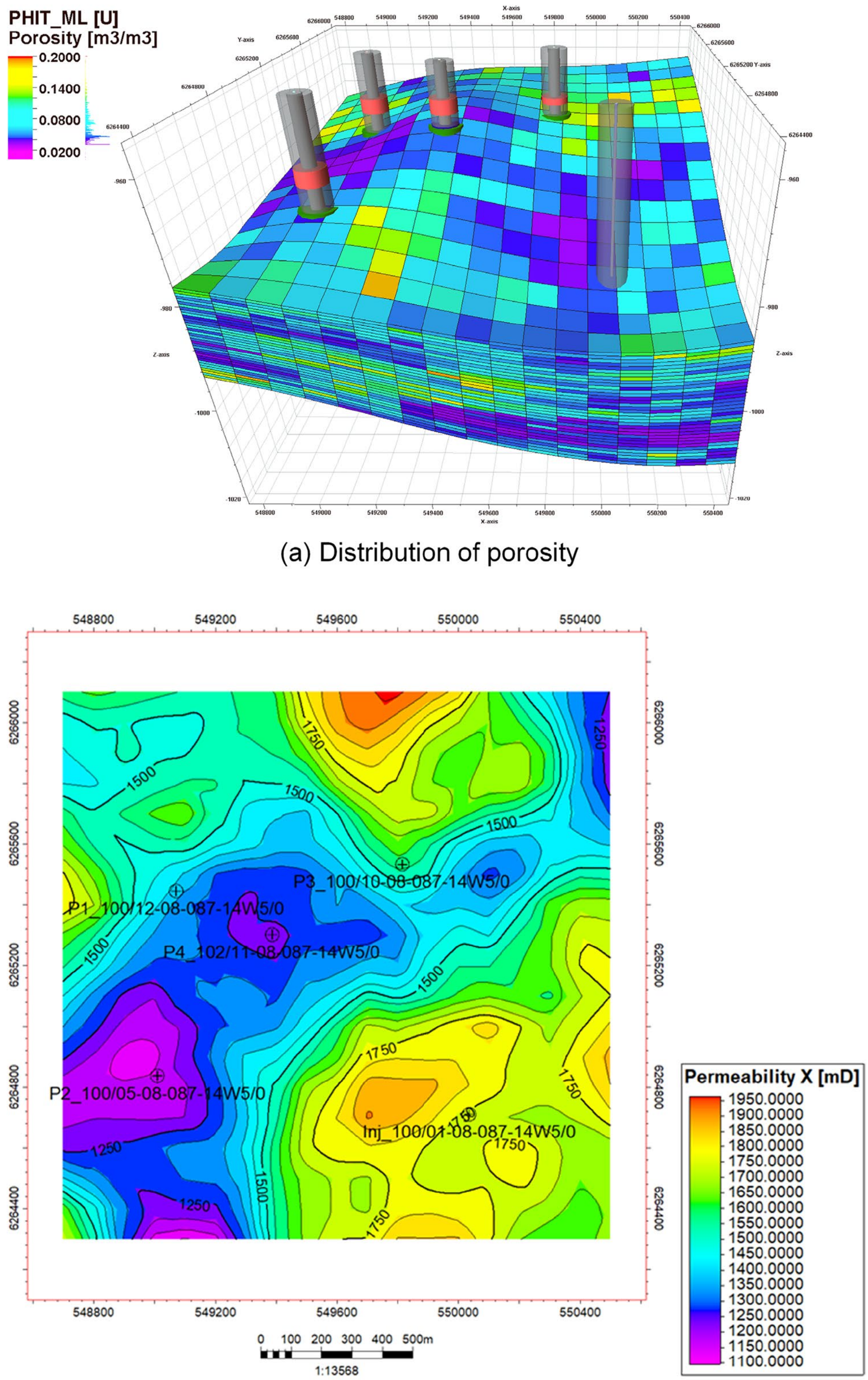


Fig. 1 Production history for an oil producer 100/12–08-087-XXXXX from the target field, showing an increase of up to 90% in water-cut (Cum.: Cumulative)



(a) Distribution of porosity

(b) Distribution of permeability

Fig. 2 Distribution of reservoir **a** porosity and **b** permeability with the location of the five wells

Flow control valve management strategy

Figure 3 depicts the location of automatic FCV for the four production wells in our target field. Depending on the available core permeability data, two to three FCVs were installed with a packer. Considering an optimized FCV control, the multi-segmented well model (Holmes et al. 1998) was employed. The valve opening represented as the

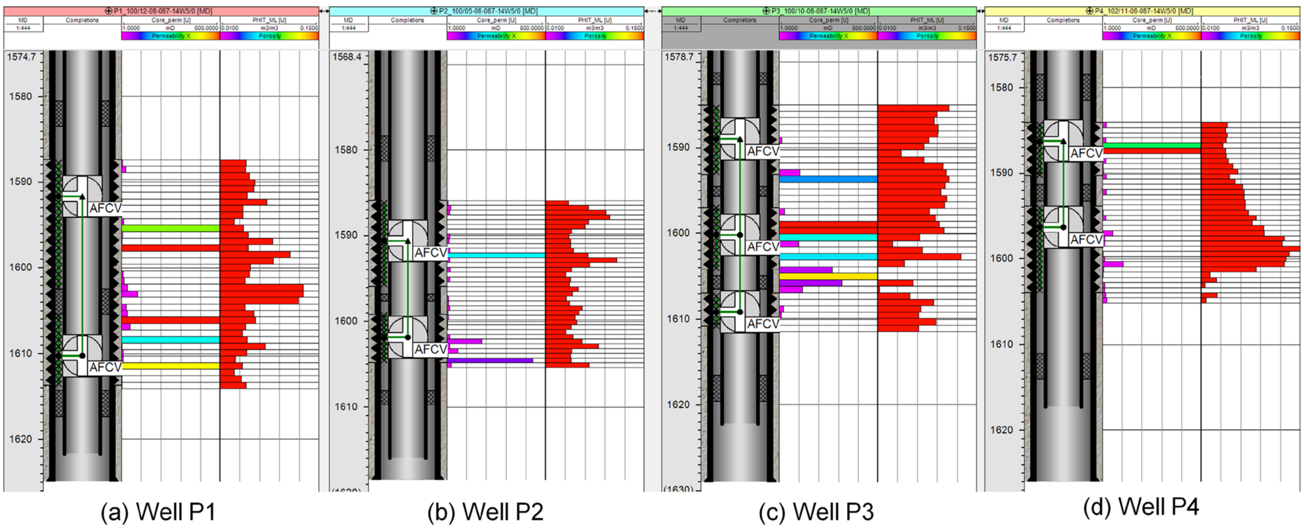


Fig. 3 Locations of FCVs for **a** P1, **b** P2, **c** P3, and **d** P4 production wells

fractional open area is a controllable parameter when performing FCV optimization.

FCV was optimized using the following approaches: rigid and flexible strategies. A rigid control can be easily used for flow simulation owing to the predetermined explicit controllability at a specific time step without additional factors (Ahmed et al. 2019). In contrast, a flexible control enables the devices to operate in a proactive and/or reactive optimization manner according to the predetermined rule-based strategies (Kuk et al. 2021). The latter is useful for controlling the operational conditions in real time, such as the valve opening of a production well in response to the observed data, such as the water cut or oil production rate. Consequently, local optimization can be easily applied to flexible control, thereby reducing the simulation cost for deriving an optimal solution. In addition, it can be more effectively applied as an optimization method of FCV to an actual field because the recently manufactured all-electric FCV can transmit data at a frequency higher than that of the conventional hydraulic FCV. Therefore, a flexible control strategy applicable at the device level was employed for optimizing production in the target field in this study.

A proactive approach in the flexible optimization strategy is to increase the sweep efficiency by delaying the entry of unwanted fluid, while a reactive approach is to maximize oil production based on the current status of inflow for each zone, such as the indicator of water cut and gas oil ratio (Grebenkin and Davies 2012). Figure 4 is a conceptual diagram illustrating flow balancing and streamline balancing, which are representative strategies of proactive optimization.

Flow balancing indicates the balancing of the flow contribution of each completion to prevent sudden water production increase owing to biased production at a certain completion. We control the openings of FCVs, x, for obtaining similar production rates for multiple completions using the following objective functions:

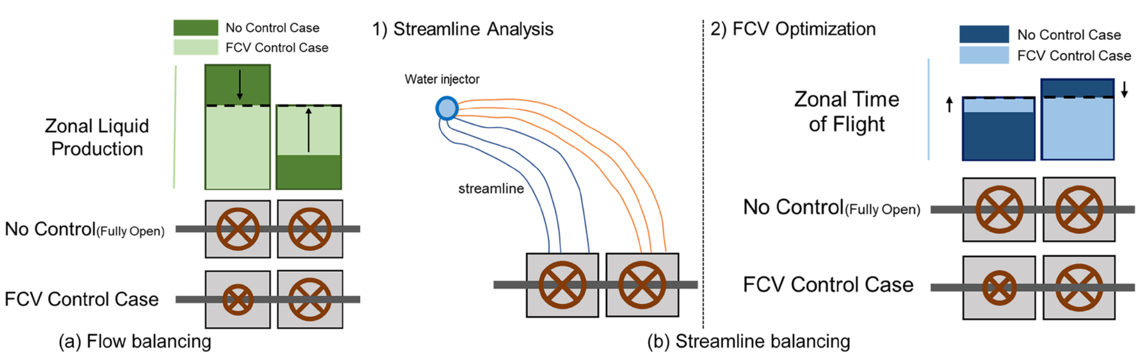


Fig. 4 Conceptual diagrams for **a** flow balancing and **b** streamline balancing strategies

$$f(x) = \sum_{i=1}^{n} \left(\frac{Q^t_{\mathrm{res}_i} - Q_{\mathrm{res}_i}}{Q^t_{\mathrm{res}_i}} \right)^2, \tag{1}$$

$$Q^t_{\mathrm{res}_i} = \frac{BF_i}{\sum_{j=1}^{n} BF_j} \sum_{j=1}^{n} Q_{\mathrm{res}_j} \tag{2}$$

where x is the vector of flow control device settings, n is the number of flow control devices, BF is the zonal production rate balancing factor that could be a user-defined ratio or the zonal permeability perforation length, for each flow control device, Q_{res} is the calculated zonal production phase flow rate for a flow control device, and Q^t_{res} is the target zonal production phase flow rate for a flow control device.

Streamline balancing slows down water breakthrough using the streamline. Through streamlined simulation (Thiele et al. 2010), we can calculate the time of flight (TOF) from an injector to the producer using Eq. 3.

$$\tau(s) = \int_{0}^{s} \frac{d\zeta}{v(s)}, \tag{3}$$

where ζ is the coordinate along a streamline, s is the distance along the streamline corresponding to the coordinate, and v is the flow velocity.

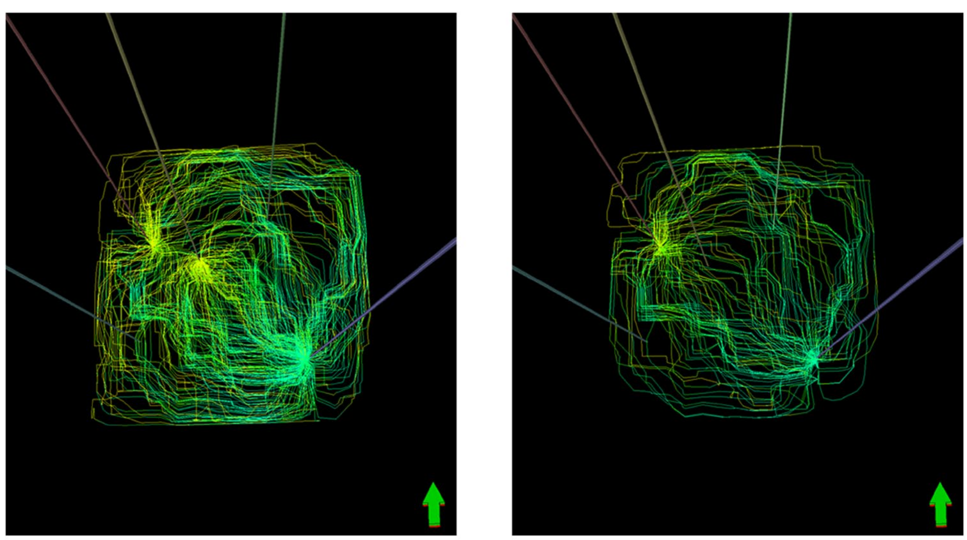
TOF is an indicator used to estimate the time point of water breakthrough at the producer. FCV is opened to increase TOF from an injector until each completion. Figure 5 shows an example of the streamlined distribution used to determine the opening of FCV. With streamline-based balancing, streamlines are distributed in wider ranges that result in higher sweep efficiency and delayed water breakthrough.

Different from proactive optimization, reactive optimization controls the FCVs to curtail the production of unwanted fluids directly. The reactive optimizer typically uses a fiscal calculation algorithm that considers the oil prices and water/gas treatment costs. Because the FCVs are controlled to maximize revenue based on the sales and processing costs of each fluid, optimization is performed to minimize the objective function shown in the following equation. Because gas is not produced in our target field in this study, Q_g and C_g are not considered.

$$f(x) = -\sum_{i=1}^{n} WF_i \left(P_o Q_{o_i} - C_w Q_{w_i} - C_g Q_{g_i} \right), \tag{4}$$

where x is the vector of the FCV settings, n is the number of FCVs, WF is the weighting factor for FCV, P_o is the oil price, Q_o is the surface oil production rate for FCV, C_w is the water processing cost, Q_w is the surface water production rate for FCV, Q_g is the surface gas production rate for an FCV, and C_g is the gas processing cost.

Nonlinear programming optimization is employed to minimize the objective function used in the proactive and reactive optimization strategy with multiple linear and nonlinear constraints. On the one hand, typical linear constraints include the minimum and maximum opening valve sizes of FCVs. The maximum opening value is typically set to 1, indicating a fully open state, but the minimum opening values may vary depending on the device



(a) Streamline balancing

(b) Without optimization

Fig. 5 Comparison of streamline distribution using **a** streamline balancing strategy and **b** without optimization specifications or field production plans. On the other hand, nonlinear constraints typically include the maximum pressure drop in devices and minimum bottom hole pressure. These constraints are set in well modeling for reservoir simulation.

Economic evaluation of optimization strategy

We used the net present value (NPV) for economic evaluation to compare the effects of completion optimization strategies in the target field. NPV can be computed by the summation of the present values (PVs) of the annual net cash flows of the same equity. NPV considers the time value of money to appraise long-term projects. Annual cash flow comprising the revenue, cost, profit sharing, and tax is discounted to its present value at a certain time using Eq. 5.

$$PV = {}^{NCF}/_{(1+R)^n} \tag{5}$$

where PV is the present value, NCF is the net cash flow, n is the number of years to be discounted, and R is the discount rate.

Table 1 Economic assumptions for net present value (NPV) calculation

Name		Value
Discount rate (%)		10
Oil price ($/bbl)		80
OPEX	Water processing cost ($/bbl)	2
	Water injecting cost($/bbl)	2
CAPEX	Drilling cost (MM$/well)	1
	FCV installing cost (MM$/valve)	0.1

For the calculation of NCF, we consider the revenue from oil sales and the treatment cost of gas and water for reinjection. With the discount rate and total period of the project (N) provided, NPV can be computed by the sum of this PV, as shown in Eq. 6.

$$NPV = \sum_{n=0}^{N} NCF/(1+R)^n \tag{6}$$

Table 1 shows the factors for NPV calculation, such as the product price and processing cost.

Results and discussions

Effect of advanced completion optimization

First, we compared the simulation results of the cases without FCV control and with FCV control to examine the effects of optimization strategies applied to the target field with the risk of production of large amounts of water. In this study, the case with FCV control is indicated by the term advanced completion optimization (ACO), while the base case does not employ ACO. All the reservoir simulation runs applied to the optimizations were performed using the high-resolution reservoir simulator (Schlumberger 2020a, b).

As described in Sect. "Description of reservoir modeling", there are various optimization strategies for controlling FCVs. Among them, the most effective optimization strategy in the field is flow-balanced optimization. In this section, we compare the overall performance with and without ACO based on the field's cumulative oil and water production. Figure 6 shows the field's cumulative oil and water productions and field water-cut according to the

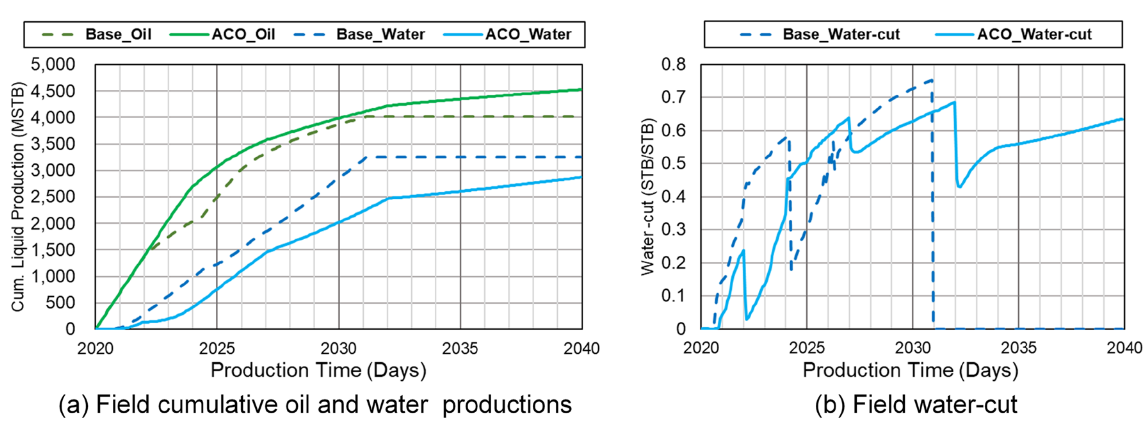


Fig. 6 Comparison of the field's **a** cumulative liquid production and **b** water-cut between the base and advanced completion optimization (ACO) cases

production period. With ACO employed, the field's cumulative oil production is 4.53 MMSTB, producing approximately 0.52 MMSTB (13% increase) more oil than the base case. The field's cumulative water production is 2.87 MMSTB, indicating approximately 0.48 MMSTB (20% decrease) less water production than the base case.

Additionally, the field-level effect of advanced completion can be confirmed through a comparison of the field water cut, as shown in Fig. 6b. In the base case, all production wells were finally closed, and field production ended after reaching the water cut limit of 0.75 in 2031. In contrast, fluids were continuously produced without exceeding the water cut limit in the ACO case. The water cut drastically decreased in 2024 and 2031 in the base case and 2022, 2027, and 2032 in the ACO case, as shown in Fig. 6b. This is due to production stoppage when each well's water cut limit was reached. Applying ACO does not directly optimize the behavior of the field-scale fluid but optimizes the well-scale fluid production with the installation of an FCV and increases the total oil production from the field. Therefore, we compared the production rates of oil and water corresponding to each device in the ACO case to analyze its effect in depth.

Figure 7 shows the production rates of water and oil corresponding to each device of the wells. The left side (Fig. 7a, c, e, g) represents the results of the base case simulation, and the right side (Fig. 7b, d, f, h) represents the results of the ACO case. In the base case, the majority of oil is produced for the second device of the P3 production well at the beginning of the production period. The oil production rate for the device is 944 STB/d (≈ 150 Sm^3/d), which is the maximum rate for a single production well. Additionally, considering that the maximum oil handling capacity of the field is 1,888 STB/d (≈ 300 Sm^3/d), the oil rate in the P3 well accounts for 50% of the total field oil rate, implying that field oil production is highly dependent on a single production well. However, the water production rate for the device increases rapidly as oil production continues, and the P3 well will finally be shut down in 2024. After P3 well is shut down, the oil production rates in the P1 and P4 wells will increase instantaneously, and the water production rates will begin to increase in the corresponding production wells; in fact, all the production wells will finally be closed around 2031. Moreover, in the case of ACO applying the flow-balanced optimization strategy, the opening of FCV in the zone with a high production rate is reduced, and the opening of FCV in the zone with a low production rate is increased to balance the oil production rate in each production well. At this time, FCVs are adjusted in the range between 0.001 and 1.

Figure 8 shows the valve control results for each device. As a result of the optimization of FCVs in the P3 well that demonstrated the highest oil production rate, the opening value of the second device is simultaneously reduced to 0.001 with the onset of production, significantly reducing the oil production rate. Because the valve opening value in the second device is adjusted to the minimum, the water breakthrough is delayed. However, the water production rate increases rapidly as the water production starts, and the second device is shut down earlier than that in the base case. Nevertheless, the first device is not shut down even though the second and third devices are shut down early because the water production rate increases in the P3 well, as shown in Fig. 8c.

Meanwhile, in the case of the base case simulation, all the devices in the production wells are not controlled; thus, they are fully open. Therefore, the device in the P3 well is shut down when the water cut of the second device reaches 0.75. The completion optimization is applied in the same manner in the other production wells (Fig. 8), and the changes in oil and water production rates according to the device optimization are shown in Fig. 7. As analyzed thus far, oil production decreases because of the device adjustment of the P3 well that significantly increases the production rates of the other production wells. Particularly, the oil production rates of the P2 well increase significantly, which can be confirmed by comparing Fig. 7c, d. This change in production rates is the result of the application of ACO, with the flow-balanced strategy complexly affecting the fluid flow characteristics in the reservoir and the production conditions of the field.

Therefore, the cumulative oil and water productions for each well vary depending on whether the completion optimization is applied (Fig. 9). For the change in cumulative production for each well, the cumulative oil productions of P1 and P3 wells decrease. However, the cumulative water production decreases further owing to the optimization. In addition, in the case of P2 and P4 wells, the cumulative oil and water productions increase significantly compared with the base case. In particular, the cumulative oil production of the P2 well increases more than 10 times. Overall, as can be observed from the field's cumulative oil and water productions in Fig. 6, more oil can be produced while reducing water production by applying optimization. Thus, we calculate and compare NPV based on the cumulative oil and water productions to determine the effect of smart completion as the economic value. As a result, the NPV of the ACO simulation was approximately 23 MM$ higher than that of the base case. Accordingly, it is possible to confirm the economic improvement with ACO applied to the target field.

Comparison of the completion optimization strategies

The completion optimization of the device units affects the oil and water production rates in each well but does not directly optimize the field-level fluid production. Nevertheless, the changes in the fluid production rates of

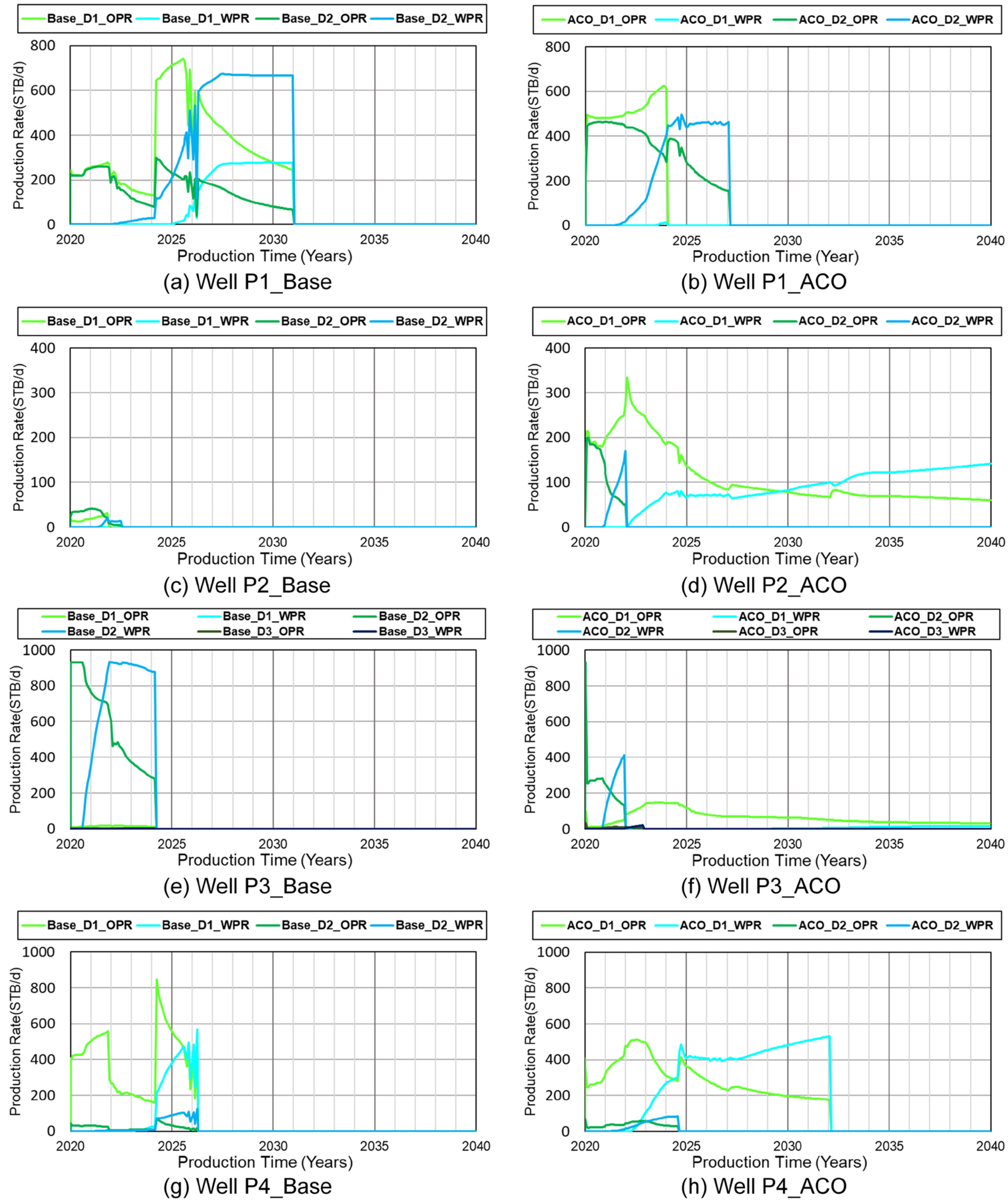


Fig. 7 Comparison of oil production rate (OPR) and water production rate (WPR) of production wells for each device between base and ACO cases

wells according to the adjustment of each device facilitate obtaining different results based on complex interactions with the fluid flow characteristics of the reservoir. In addition, it is possible to plan an economical production scenario for the target field, as shown in Fig. 6. The result of ACO might vary depending on the optimization strategy and the controllable opening range of the valves. Therefore, a comparison analysis for related strategies and parameters is performed to determine an appropriate FCV setting to maximize the NPV of the field. Furthermore, the optimization result may vary depending on the field constraints, such as the maximum oil and water treatment capacity of the field and the field water cut; nonetheless, in this study, we used the fixed field constraints of the field.

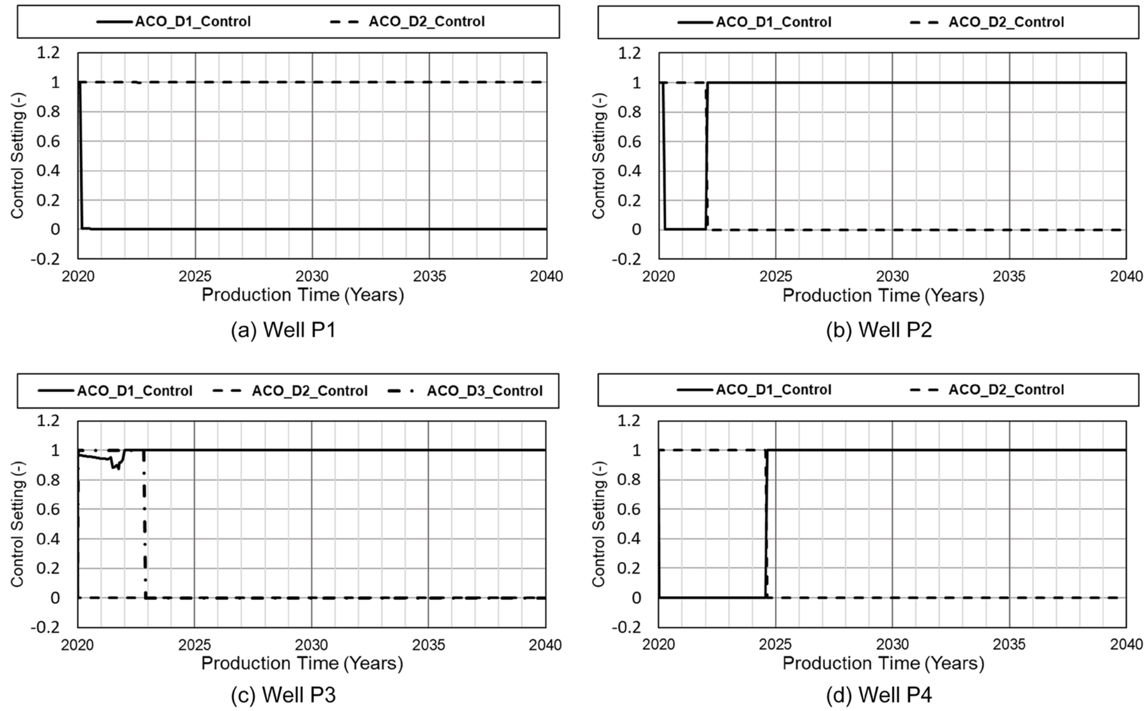


Fig. 8 Results of valve settings for each device with ACO applied to **a** P1, **b**, P2, **c** P3, and **d** P4 production wells

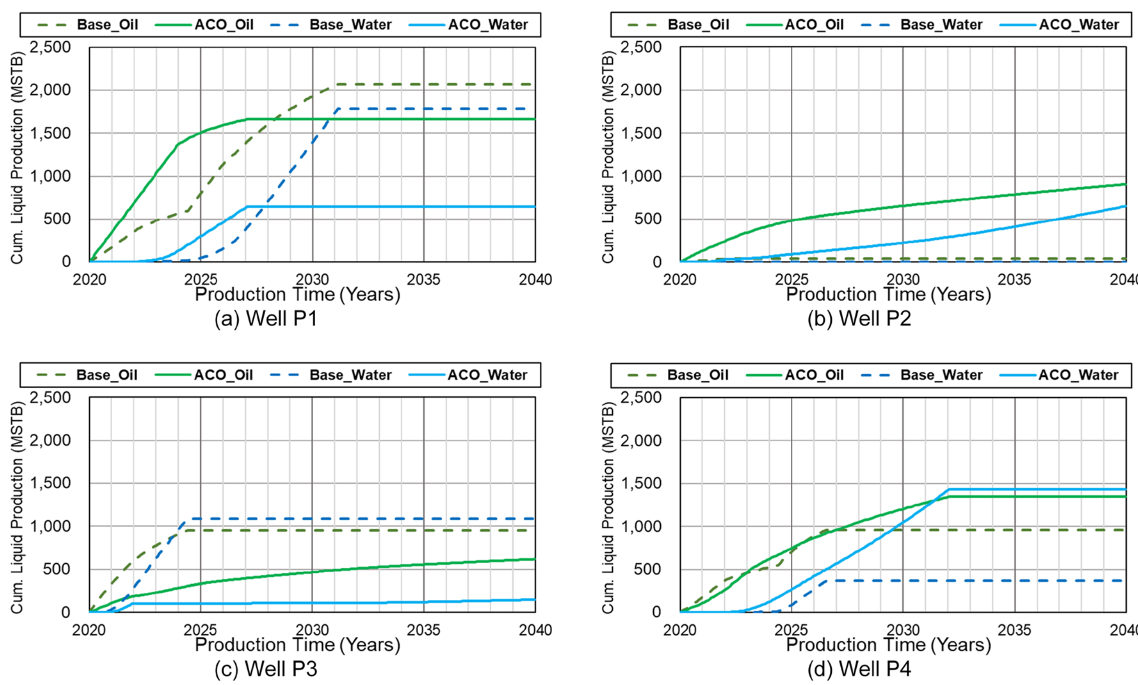


Fig. 9 Comparison of cumulative oil and water productions of **a** P1, **b** P2, **c** P3, and **d** P4 production wells between the base and ACO cases

Proactive strategy: flow balancing versus streamline

As mentioned earlier in the methodology section (Sect. "Methodology"), there are two main strategies of proactive optimization for delaying water production. The first strategy is flow balancing, which directly equalizes the production rate of fluids. The second strategy is streamlining, which slows down the water breakthrough. Different from the first strategy, it calculates and equalizes TOF. In this study, these strategies are applied to the target field to compare the two types of proactive optimizers.

The field's cumulative oil and water productions are compared with those of the base case, as presented in Table 2 and Fig. 10. As a result, the cumulative field oil productions of the ACO cases are higher, while the cumulative field water productions are lower than that of the base case. Both strategies are effective in delaying water production, which is the main objective of the proactive optimizer. Particularly, in the case of the streamline optimizer, the cumulative field water production is the smallest until 2036. However, as a result of delaying the water production in the target field with a high water cut, the field oil production also decreased, as shown in Fig. 10a. Even by 2036, the cumulative field oil production will be lower than that of the base case, and NPV will be the lowest among the three cases.

Moreover, in the case of the flow balancing optimizer, rather than directly delaying water production, it controls the indirect effect of focusing on the equalization of liquid production. Consequently, until 2036, the water production is expected to be slightly higher than that of the case applying the streamline, but it is possible to suitably optimize the liquid production by increasing the oil production compared with the base case. In these comparisons, the results according to the water production delay for both strategies are significant when comparing the NPV. Accordingly, we have confirmed that the flow balancing strategy is more appropriate than the streamlined strategy in the field with high water-cut flow behavior.

Application of reactive strategy

Strategies for FCV optimization are typically classified into proactive and reactive according to the optimization approach. In the application of such strategies, a single- or hybrid-type optimizer may be used. When a hybrid-type optimizer is applied, it functions by switching according to the field constraints modeled. In this study, the proactive optimizer, which is the initial FCV optimizer, is switched to the reactive optimizer when the field water-cut exceeds 0.5. Table 3 and Fig. 11 show the simulation results with and without the reactive optimizer applied. In addition, when a hybrid-type optimizer is used, the flow balancing optimizer is used as a proactive optimizer that has high economic efficiency, as analyzed in Sect. "Proactive strategy: Flow balancing versus Streamline". As a result of FCV optimizations using a single-type optimizer, the cumulative oil production is higher, and the cumulative water production is lower than that of the base case in both cases. However, until 2035, the NPV with the reactive optimizer is expected to be lower than that of the base case due to low oil production. Furthermore, a hybrid-type optimizer shows a production trend different from that of the case using only the proactive optimizer from the time the field water-cut reached 0.5. It is relatively less economical when comparing the NPV.

Table 2 Results of applying the proactive optimizer

Proactive optimizer	Field's cumulative oil production (MSTB)	Field's cumulative water production (MSTB)	NPV(MM$)
Base (No control)	4012.90	3246.77	203.14
Flow balancing	4527.63	2871.02	226.13
Streamline	4169.34	3123.98	188.88

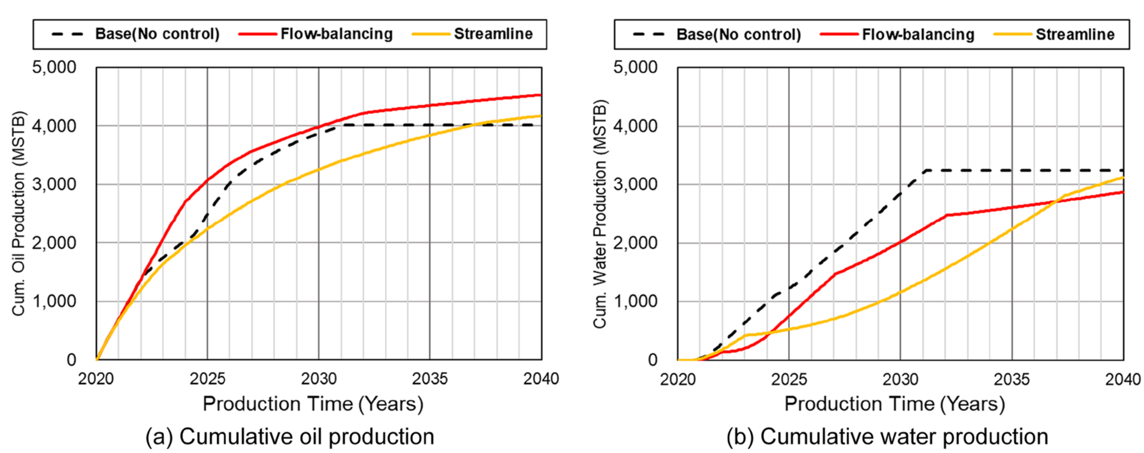


Fig. 10 Comparison of the field's cumulative a oil and **b** water production results according to the application of the proactive optimizer

Table 3 Results of application of the reactive optimizer

Optimizer	Field's cumulative oil production (MSTB)	Field's cumulative water production (MSTB)	NPV(MM$)
Base (No control)	4012.90	3246.77	203.14
Proactive optimizer	4527.63	2871.02	226.13
Reactive optimizer	4267.98	3090.39	199.15
Hybrid optimizer	4453.73	3048.08	221.10

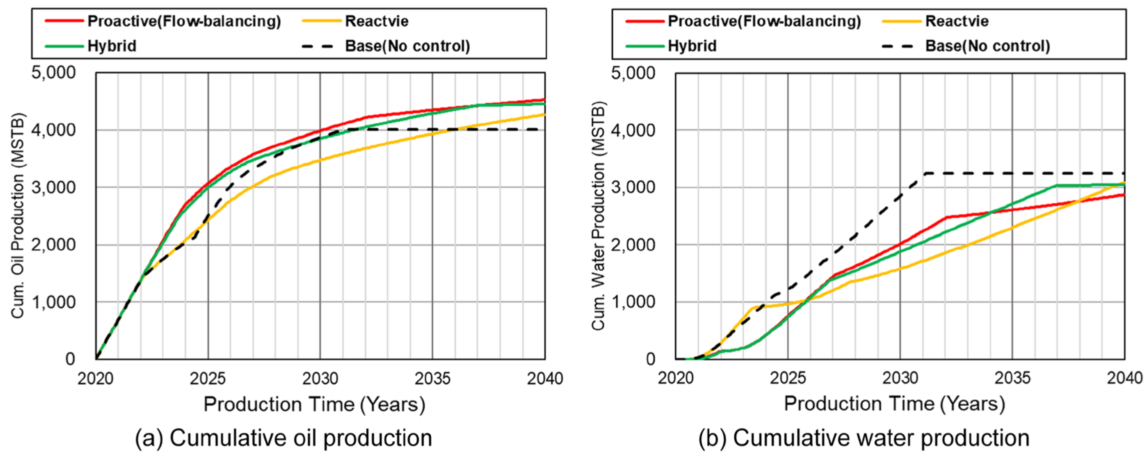


Fig. 11 Comparison of the field's cumulative **a** oil and **b** water production results according to the application of the reactive optimizer

Considering these results, the optimization based on the reactive approach is ineffective compared with that based on the proactive approach, that is, flow balancing, in the target field. Although reactive optimization is widely considered an appropriate strategy to limit water production in the field, it causes a decrease in oil production and adversely affects the economics of field production. In addition, the uneconomical liquid production trends relative to the production in the base case are similar to the results of the streamline optimizer case analyzed in the previous section. Although the streamline and reactive approaches optimize the FCVs differently, water production is the main control target with different parametric indicators, such as the water breakthrough time or production quantity. Moreover, the flow balancing approach controls water production indirectly because it is regulated in the process of equalization of liquid production.

Flow control valve minimum opening size

Depending on the type of optimization strategy employed, the minimum opening size of FCV is also an important factor for advanced completion owing to the balancing of the oil production in each well. To analyze its effect, we compare the results for three minimum opening sizes as presented in Table 4 and Fig. 12. Therefore, the highest cumulative oil production and NPV were obtained when the minimum opening value of FCV was set to 0.001. This setting value is the minimum opening size that can be set in well completion modeling, and it is almost similar to the closed state because only 0.1% of the valve is opened. In addition, the cumulative oil production tends to decrease as the minimum opening value increases. From these results, it can be confirmed that the more rigorous the flow control of the fluids, the more positive results through completion optimization are obtained. However, in the case of cumulative water production, owing to the mixed results shown in Table 4, there is no specific tendency observed based on the size of the FCV.

As assumed in Table 1, because the oil price is higher than the cost of water injection and processing, the smaller the minimum opening size, the higher the oil production and the higher the profits of the field. Nevertheless, water production must also be considered to accurately evaluate the economic feasibility of the field. Therefore, the minimum

Table 4 Results with different minimum FCV opening sizes

Valve opening	Field's cumulative oil production (MSTB)	Field's cumulative water production (MSTB)	NPV(MM$)
0.001	4527.63	2871.02	226.13
0.005	4470.63	3571.63	221.01
0.05	4381.70	2867.11	219.76

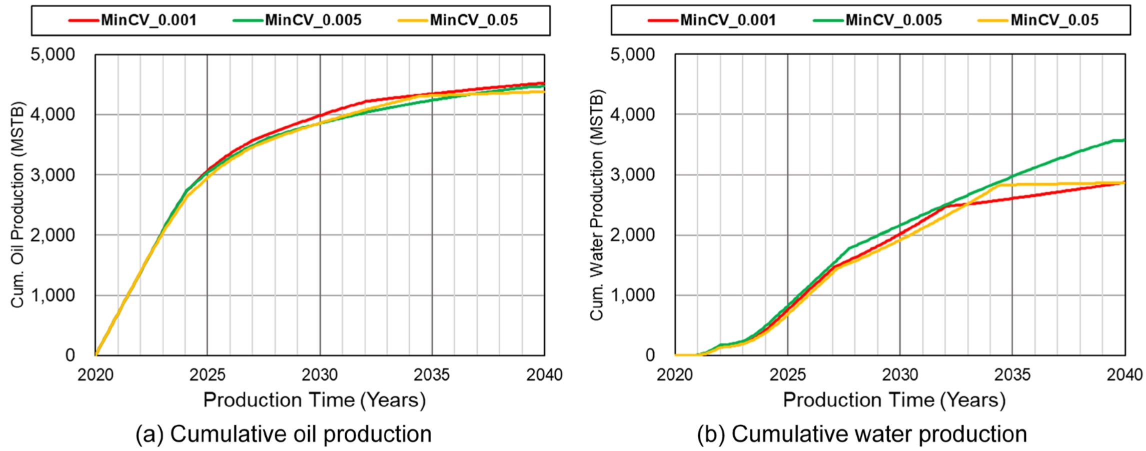


Fig. 12 Comparison of the field's cumulative **a** oil and **b** water production results according to the minimum FCV opening size

opening size of FCVs should be set by comparing the optimization results according to the various settings.

Conclusions

Studies on smart field management using downhole devices have increased recently. This research focuses on the management of flow control valve (FCV) for optimizing the fluid production of an actual onshore field in Alberta, Canada, with a high water-cut problem. The study investigated proactive and reactive strategies, including flow-balancing and streamline strategies and a hybrid of the proactive and reactive strategies. A sensitivity analysis for the minimum valve opening size was conducted. Detailed analysis from the field level to the device level confirmed that the adjustment of each FCV enables complex interaction with the fluid flow characteristics of the reservoir and production scenario. A summary of the main findings is as follows:

(1) As a result of FCV optimization based on the flow-balancing strategy, the revenue of the target field increased by approximately 23 MM$ by maximizing oil production and suppressing water production. In addition, by controlling FCVs, the oil production of most wells was maintained longer than that of the base case due to the delay in time to reach the well water-cut limit.
(2) In most optimization cases, including proactive and reactive strategies, the cumulative water production could be reduced compared with the base case. Nevertheless, each case does not always positively affect the field's economic feasibility. The streamline-balancing and reactive strategies, which directly involve water control, may cause a decrease in oil productivity and undermine the economic feasibility of the field with the risk of high water-cut during water flooding.
(3) The sensitivity analysis for minimum valve opening size confirmed that the rigorous flow control of the fluids had a significant positive effect on the oil productivity of the well. Nevertheless, because the amount of water produced was uncertain according to the size, the appropriate size must be set to maximize the economic value of the field.

The following issues can be considered in future studies:

(1) The reservoir model and production scenario used in this study were established based on a sector model of the actual field, not the entire field. In future studies, completion optimization can be applied to the full-field production scenario of the target field.
(2) The effects of FCV optimization can be analyzed in the fields considering complex fluid behaviors in the three phases (oil, gas, and water) or various production problems such as flow regime issues.

The results of this case study of completion optimization in an actual Canadian field could be used as a reference to optimize downhole devices when applying water flooding in fields where high water-cut is expected.

Author contributions SA contributed to writing—original draft preparation, conceptualization, methodology, software, formal analysis, visualization. KL contributed to writing—original draft preparation, methodology, software, investigation, visualization. JC contributed to validation, writing—review and editing. DJ contributed to conceptualization, resources, writing—review and editing, supervision.

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Declarations

Conflict of interest The authors have no competing interests that are relevant to the content of this article.

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