

Article

Techno-Economic Optimization of Hot-Water Flooding and Injection Conversion Strategies for a Heavy Oil Reservoir: A Case Study of the A66 Block

Guangming Ren ¹, Haotian Zhang ¹, Ming Zhu ^{2,*}, Yuwei Feng ³, Tianyu Liu ² and Yi Liu ⁴

¹ PetroChina Oil, Gas & New Energies Company, Beijing 100007, China; renguangming@petrochina.com.cn (G.R.); dg_zhhtian@163.com (H.Z.)

² Research Institute of Petroleum Exploration & Development, Beijing 100083, China; tianyu.liu@petrochina.com.cn

³ Petrochina Tarim Oilfield Company, Korla 841000, China; fengyw-tlm@petrochina.com.cn

⁴ School of Architecture and Construction, Jilin Jianzhu University, Changchun 130118, China; liu.yi-1987@foxmail.com

* Correspondence: mingzhu@petrochina.com.cn

Abstract

Heavy oil reservoirs typically suffer from low recovery efficiency and high development costs during thermal production. This study investigates the A66 heavy oil reservoir and proposes an integrated hot-water flooding and hot-to-cold injection strategy. Laboratory experiments, numerical simulations, and techno-economic analysis are combined to optimize injection temperature, conversion timing, and injection parameters. Results show that injection temperature strongly affects oil recovery. Increasing temperature from 40 °C to 60 °C significantly improves recovery by reducing oil viscosity and enhancing mobility. However, further increases to 80 °C and 100 °C provide only marginal additional improvement, indicating a clear diminishing return effect. Considering both recovery performance and energy consumption, 60 °C is identified as the optimal injection temperature. Simulation results indicate that the timing of hot-to-cold conversion has a limited impact on final recovery, while significantly affecting development cost. A conversion window at a water cut of 10–20% achieves a balanced performance between displacement efficiency and thermal cost reduction. In addition, unstable injection improves sweep efficiency by dynamically adjusting flow paths and enhancing both areal and vertical displacement. A coupled hot-to-cold injection strategy is therefore proposed. It integrates temperature optimization, injection mode design, and conversion timing to improve both recovery and economic performance. Compared with conventional constant-temperature flooding, the proposed strategy better accounts for the time-dependent evolution of reservoir thermal conditions and fluid properties. Techno-economic evaluation confirms that the optimized scheme achieves higher economic efficiency while maintaining stable recovery improvement, demonstrating strong potential for field application in similar heavy oil reservoirs.



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Keywords: heavy oil reservoir; hot water flooding; injection conversion timing; numerical simulation; development optimization

1. Introduction

Heavy oil resources are widely distributed worldwide and constitute a significant portion of unconventional hydrocarbon reserves, with geological reserves far exceeding those of conventional crude oil [1,2]. According to available statistics, the proven geological

reserves of conventional crude oil globally are approximately 4.2×10^{11} t. In contrast, the reserves of heavy oil and bitumen are 1.55×10^{12} t, more than three times those of conventional oil. This highlights the tremendous development potential of heavy oil and its increasingly important role in the future global energy structure. As conventional hydrocarbon resources continue to be depleted and energy demand grows, efficient exploitation and utilization of heavy oil resources have become a critical challenge for the petroleum industry. Therefore, optimizing development techniques to improve heavy oil recovery and expand recoverable reserves is strategically significant for energy security, efficient resource utilization, and sustainable hydrocarbon development.

Compared with conventional crude oil, heavy oil typically exhibits high viscosity, high density, and elevated resin and asphaltene content [3]. These physical properties lead to poor mobility and low flowability under reservoir conditions, significantly increasing flow resistance and reducing displacement efficiency. Moreover, the high resin and asphaltene content can cause pore-throat blockage and complicate two-phase oil–water flow, posing greater technical challenges for reservoir development [4]. Under conventional recovery conditions, the high viscosity of heavy oil prevents displacement fluids from effectively mobilizing the oil, resulting in low reservoir utilization and limited recovery [5,6]. Therefore, reducing heavy oil viscosity, enhancing its mobility, and improving overall reservoir utilization remain central issues in heavy oil development research.

To date, numerous studies have been conducted on heavy oil recovery technologies, yielding several development strategies [7–9]. Common methods include thermal recovery (such as steam huff-and-puff, steam flooding, and in situ combustion) [8,10], cold production [11,12], chemical viscosity reduction [13,14], microbial enhanced oil recovery [15,16], and recently developed novel viscosity reduction techniques [17]. Among these, thermal recovery, which injects high-temperature fluids into the reservoir to raise formation temperature and significantly lower oil viscosity, is considered the most effective and widely applied approach for improving heavy oil development efficiency [18,19]. As temperature increases, intermolecular forces in the oil weaken, viscosity decreases, and the flow characteristics of oil–water two-phase systems improve, facilitating oil displacement and markedly enhancing recovery [20].

However, in practical development, variations in injection temperature often lead to redistribution of the reservoir temperature field, affecting formation flow capacity and fluid flow behavior [21]. In particular, when low-temperature fluids are injected, or when development transitions from hot water to cold water, reservoir cooling can rapidly increase oil viscosity. At the same time, changes in pore structure and relative permeability may occur, producing the so-called “cold damage” effect [22]. Cold damage in heavy oil reservoirs is generally associated with a temperature-induced increase in crude oil viscosity and a reduction in effective permeability caused by wax precipitation and pore-throat blockage. Cold damage not only reduces oil mobility but also increases oil–water flow resistance, thereby lowering displacement efficiency and adversely affecting recovery [23]. Consequently, during hot-water flooding, controlling injection temperature and mitigating cold damage are key technical challenges for efficient heavy oil recovery [24,25]. Nevertheless, systematic studies on the coupling among injection temperature, cold-damage effects, and development strategy during hot-water flooding remain limited, and the underlying mechanisms and optimization methods require further investigation.

Based on this research background, this study focuses on the A66 heavy oil reservoir in the Alashan region. Due to the site’s confidentiality, A66 refers to the code name of a certain well. By systematically analyzing reservoir geological characteristics and crude oil properties, and combining oil displacement efficiency experiments, relative permeability measurements, and numerical simulation techniques, this work investigates the effect

of injection temperature on heavy oil reservoir development performance. Particular attention is given to the evolution of fluid mobility and displacement efficiency under thermal conditions, as well as the potential occurrence of cold-damage effects induced by low-temperature injection during development transitions.

On this basis, a comprehensive optimization of the hot-water flooding development strategy is conducted, including the optimization of displacement fluid temperature, the determination of injection conversion timing, and the selection of stable and unstable water injection schemes. In addition to laboratory experiments and numerical simulations, a techno-economic evaluation is further introduced to assess development performance from both technical and economic perspectives, enabling a more practical evaluation of different recovery strategies.

Importantly, the main novelty of this study lies in the proposal of a coupled hot-to-cold water injection conversion strategy for heavy oil reservoir development. Unlike conventional studies that primarily focus on optimizing single-stage thermal flooding parameters or maintaining constant-temperature injection conditions, this work establishes a dynamic development framework that integrates thermal viscosity reduction, reservoir flow evolution, and economic efficiency within a unified strategy. The proposed conversion mechanism explicitly accounts for the dual effects of temperature variation: the positive effect of high-temperature injection in reducing crude oil viscosity and enhancing mobility, and the negative impact of low-temperature injection in inducing potential cold-damage behavior and altering flow resistance. By introducing a controlled transition from hot-water flooding to low-temperature water injection at an optimized water-cut threshold, the proposed strategy enables a balanced trade-off between displacement efficiency and operational cost reduction. Therefore, this study extends beyond traditional parameter-optimization approaches and provides a more systematic, field-applicable development framework for heavy oil reservoirs. The results are expected to offer theoretical support and practical guidance for the efficient and economical development of similar heavy oil resources.

2. Reservoir Overview

2.1. Geological Structure and Reservoir Characteristics

The A66 block is located on the western slope of the Songliao Basin, within the Tangchi structural belt. Geographically, it lies approximately 9 km northeast of the Alashan gas field. The block's surface conditions are favorable, with relatively flat terrain and convenient transportation. The well sites are situated in cultivated areas and can be accessed directly via paved roads, providing good conditions for construction and production. The A66 well, located on the western slope of the Taikang uplift zone, is an exploratory well drilled in 1992 that has provided essential geological data for subsequent reservoir studies and development planning.

Structurally, the A66 block exhibits a west-high, east-low slope pattern, with relatively simple structural features. Faults are more developed in the western part of the block, primarily trending northwest, whereas the eastern section contains only a few small-scale faults. Minor northeast-trending faults also exist within the block, but overall structural relief is limited, resulting in a gentle topography. Overall, the block presents a relatively simple anticlinal structure, with the structural high located near the A66-2 well at an elevation of approximately -620 m. Only three major faults have been identified, with lengths ranging from 0.5 to 1.3 km and displacements of 5–18 m. In general, the structural conditions are relatively stable, with small-scale faults exerting only a limited influence on reservoir continuity and fluid flow, thereby providing favorable conditions for development [26].

From a sedimentary perspective, the A66 block was influenced by multiple sediment source systems during deposition, including the Qiqihar source in the north, the Yingtai source in the south, and short-range sources to the west. During the Gaotaizi depositional stage, the northern and southern sources dominated sediment supply, controlling the development of the sedimentary system in the study area. During this period, deltaic, near-shore lacustrine, and shallow submarine-fan depositional environments predominated. The deltaic system primarily formed the prodelta subfacies, with local areas exhibiting delta plain deposits. Near the A66 well, the S1 formation predominantly contains channel sand bodies and interdistributary bay deposits, with channels extending southwestward to the Alashan area, forming relatively continuous sheet-like sand bodies. Additionally, estuarine and distal bar deposits developed in the prodelta environment provide favorable reservoir conditions for hydrocarbon accumulation.

Stratigraphically, the A66 block comprises, from bottom to top, the Quantou, Qingshankou, Yaojia, Nenjiang, Sifangtai, and Mingshui formations, overlain by tertiary and Quaternary sediments. The main reservoir is the Sartu Formation, developed within the Nenjiang and Yaojia formations. In this study, the Sartu Formation is identified as the primary target, with an overall thickness of approximately 80 m; the measured thickness at the A66 well is 82 m, with the main oil-bearing section in the S1 unit.

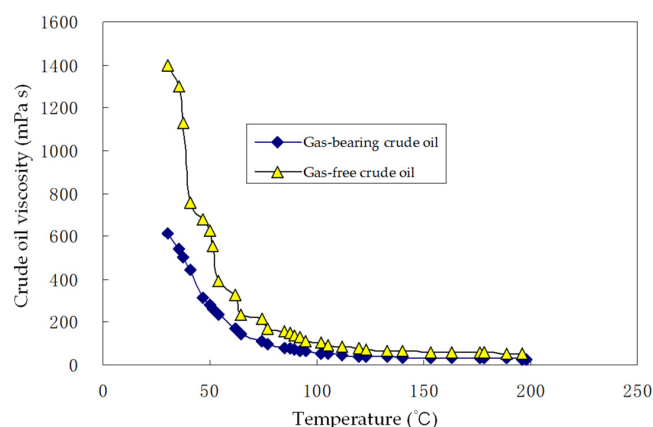
The Sartu sandstones formed in a continually expanding lake basin within the Songliao Basin, with a gradually retreating shoreline. During SI deposition, sediments were mainly derived from northern sources, leading to prodelta deposits primarily in the Alashan area and its northern regions. In contrast, most of the study area was dominated by near-shore and semi-deep lacustrine deposits. Under the influence of depositional dynamics, sand bodies trend generally northeast–southwest and are mainly concentrated from Alashan to the Erzhan area. This depositional pattern ensures relatively good lateral continuity of reservoir sands while exhibiting some heterogeneity.

Vertically, the Sartu Formation has an average thickness of approximately 75 m and can be subdivided from top to bottom into the Sa0, Sa1, and Sa2–3 units, with thicknesses of 24.7 m, 8.4 m, and 20.0 m, respectively. Each unit exhibits distinct lithological characteristics: the upper section is dominated by gray-black mudstones with thin layers of black graptolite and dark brown oil shales; the middle section consists of interbedded dark gray mudstone, silty mudstone, and gray silty mudstone; the lower section is composed of black-gray mudstone, silty mudstone, and gray silty mudstone with varying interbedding thicknesses. This multi-layered interbedding increases reservoir heterogeneity and significantly affects reservoir flow characteristics and displacement efficiency [27].

Crude oil in the A66 block is a typical heavy oil, characterized by high density, high viscosity, and elevated wax and asphaltene contents, together with a medium pour point (Table 1). The asphaltene content is 22.1%, indicating a relatively high fraction of high-molecular-weight polar components that contribute to strong intermolecular interactions and increased viscosity. Under reservoir conditions (35.6 °C and 8 MPa), the viscosity of degassed oil was measured at 1400 mPa·s, whereas the viscosity of undersaturated oil was 541 mPa·s, indicating that degassed oil viscosity is approximately 2.56 times that of undersaturated oil (Figure 1). This demonstrates the strong sensitivity of oil viscosity to dissolved gas content and temperature. A decrease in reservoir pressure or temperature can significantly increase oil viscosity, further reducing oil mobility and adversely impacting recovery. Therefore, controlling temperature to reduce oil viscosity is a critical technical approach to enhancing oil displacement efficiency in such heavy oil reservoirs [28].

Table 1. Properties of A66 crude oil.

Property	A66 Block
Oil density (g/cm ³)	0.923
Degassed oil viscosity at 50 °C (mPa·s)	409
Degassed oil viscosity at 30 °C (mPa·s)	1610
Wax content (%)	37.6
Asphaltene (%)	22.1
Pour point (°C)	15
Resin (%)	Not separately measured

**Figure 1.** Viscosity–temperature curves of degassed and undersaturated crude oil.

2.2. Well Testing and Production Overview

The A66 well, one of the primary evaluation wells in the block, provides crucial data for determining the reservoir development strategy. The perforated interval of the well is 5.2 m, with an effective thickness of 3.5 m. During the initial well testing phase, the daily oil production reached 3.64 t, corresponding to a production intensity of 1.04 t/(d·m), indicating a certain production capacity in this interval. Subsequently, in September 2004, the well entered the pilot production phase, adopting a depletion-type cold production method. During the early stage of pilot production, daily oil output increased to 5 t, with a production intensity of 1.4 t/(d·m), indicating an improvement over the testing phase and confirming that the reservoir retains development potential under natural energy-drive conditions.

Production dynamics indicate that the well is significantly influenced by edge water, with the reservoir exhibiting a certain degree of natural energy support [29]. As production continues, bottom-hole pressure gradually declines, and edge water advances into the reservoir, affecting the well's liquid production profile. In the late production stage, liquid production was controlled to reduce water cut slightly, improving overall production performance. At this stage, daily liquid production was 4.2 t and daily oil production was 2.9 t, demonstrating that the well can maintain stable production under edge-water drive conditions (Figure 2). Overall, the production behavior of the A66 well reflects the presence of natural reservoir energy while clearly exhibiting edge-water effects.

At the block scale, 31 wells have been drilled, including 29 oil wells and 2 water-injection wells. By December 2011, 29 oil wells were in production, including 25 vertical wells and 6 horizontal wells. The combination of well types has improved reservoir utilization and provides a basis for future development adjustments. As of 18 April 2012, 24 wells remained in production. At this time, the block's average water cut was 36.2%, with daily liquid production of 92.5 t and daily oil production of 59 t. Overall, the block

is in the early development stage, with relatively stable production, although reservoir heterogeneity and edge-water activity are beginning to influence production dynamics.

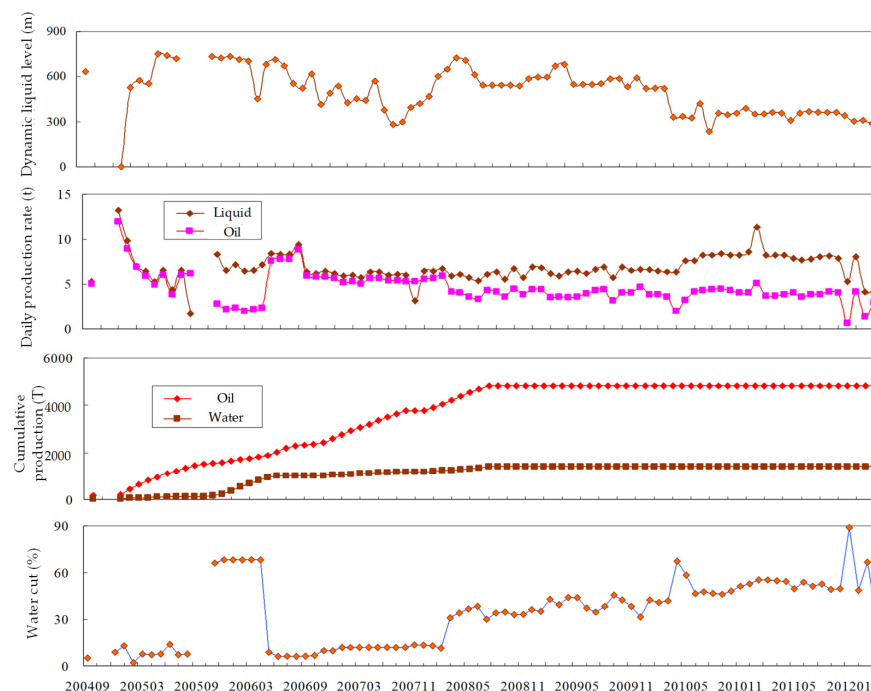


Figure 2. Production dynamic curves of the A66 well.

Spatially, water cut in oil wells is strongly influenced by structural position and reservoir lithology. Wells located on structural highs exhibit relatively low water cuts; 12 wells are producing under low-water conditions, all situated above the -630 m contour. This indicates favorable oil preservation conditions and relatively weak influence from edge-water in the high structural areas. Conversely, wells located near oil–water transition zones or close to edge-water areas exhibit higher water cuts or even full-water production. Currently, four wells are in full-water production, primarily located near the oil–water transition zone or in areas strongly affected by edge-water drive. This water distribution pattern further confirms the significant impact of edge-water drive during reservoir development.

To evaluate the natural energy characteristics of the A66 block, the industry standard “Methods for Evaluating Reservoir Natural Energy” (SY/T 5579-2008) [30] was applied, using the dimensionless elastic production ratio and the average formation pressure decline per 1% of recovered geological reserves. The dimensionless elastic production ratio is calculated as:

$$N_{pr} = \frac{N_p \cdot B_o}{N \cdot B_{oi} \cdot C_t \cdot \Delta P'} \quad (1)$$

Additionally, the average decline in formation pressure per 1% of recovered reserves is used to assess the reservoir’s natural energy replenishment capacity.

$$D_{pr} = \frac{P - \bar{P}}{100 \cdot N_p / N'} \quad (2)$$

Based on calculations, the A66 block exhibits a dimensionless elastic production ratio of 6–12, with an average pressure decline of 1.05–1.2 MPa per 1% of recovered reserves. According to the standard classification, the reservoir belongs to Class III, indicating a certain degree of natural energy, though with relatively limited replenishment capacity. Production mainly relies on elastic energy and edge-water drive.

Combining the well testing, pilot production data, and natural energy evaluation results, it can be concluded that the A66 block reservoir has an initial natural energy basis. However, as production continues, pressure declines and edge-water advancement increasingly affect development performance. Therefore, subsequent development requires appropriate displacement methods to enhance oil mobility and improve recovery. These findings provide essential engineering background and theoretical support for subsequent studies on the development of hot-water flooding.

3. Experiments, Results, and Discussions

3.1. Displacement Characteristics of the A66 Heavy Oil Reservoir

The A66 heavy oil reservoir is characterized by high colloid and asphaltene content, high oil viscosity, and poor mobility, making conventional water flooding ineffective. Hot-water flooding improves oil recovery by increasing reservoir temperature, reducing oil viscosity, and enhancing oil–water flow behavior. However, its performance is influenced not only by temperature but also by core permeability, fluid properties, and relative permeability characteristics [31].

To ensure the reliability and reproducibility of the experimental results, all core flooding experiments, injection pressure measurements, and relative permeability tests conducted in this study were independently repeated three times under identical experimental conditions. The reported results represent the averaged values of repeated measurements. The relative deviation among repeated tests was generally within $\pm 2\text{--}3\%$, indicating good experimental repeatability and low measurement uncertainty. This confirms that the observed trends in recovery factor, pressure response, and multiphase flow behavior are statistically stable and not affected by random experimental fluctuations.

In this study, natural cores from the A66 well were used to conduct systematic hot-water flooding experiments, injection pressure measurements, and oil–water relative permeability tests, providing a reliable experimental basis for parameter optimization.

3.1.1. Hot-Water Flooding Efficiency Under Different Temperatures

To investigate the effect of injection temperature on heavy oil displacement, natural cores from the A66 well were used. The cores underwent rigorous pretreatment: each core was placed in a Soxhlet extractor and continuously washed with No. 120 gasoline for more than 72 h to remove residual oil and impurities until the solvent became clear. The cores were then dried, and gas permeability was measured, while porosity and oil saturation were recorded. Core properties are summarized in Table 2.

Table 2. Natural core parameters.

Sample	Formation	Depth (m)	Diameter (cm)	Length (cm)	Gas Permeability ($10^{-3} \mu\text{m}^2$)	Sample	Formation
A66-8	K1n1	758.53	2.5	6.766	281	31.92	69.27
A66-5	K1n1	758.74	2.5	5.28	1076	30.12	68.40

To comprehensively assess the effects of temperature on recovery, seven injection temperatures (20, 40, 60, 80, 100, 120, and 140 °C) were tested in two cores with different permeabilities ($281 \times 10^{-3} \mu\text{m}^2$ and $1076 \times 10^{-3} \mu\text{m}^2$). Injection temperature was strictly controlled using a thermostatic heating system, minimizing heat loss to the core and closely simulating in situ hot-water flooding conditions. Results show that in both cores, hot-water flooding efficiency was significantly higher than that of ambient-temperature flooding, and recovery increased with temperature. This is primarily because higher temperatures reduce the viscosity of heavy oil, thereby improving its mobility in the porous medium.

As shown in Figure 3, oil recovery increases significantly with temperature, and the most pronounced improvement occurs between 20 °C and 80 °C. At 80 °C, oil recovery is high for both cores, while further increasing the temperature to 100–140 °C yields only relatively small additional gains, indicating a clear diminishing marginal effect of temperature on displacement efficiency. This behavior is consistent with the exponential reduction in heavy oil viscosity with temperature, where the sensitivity of viscosity reduction gradually weakens at higher temperatures. All core flooding experiments under different temperature conditions were independently repeated three times, and the results shown in Table 3 correspond to the mean values of these repeated measurements. The relative deviation among repeated runs was within $\pm 2\text{--}3\%$, confirming good experimental repeatability.

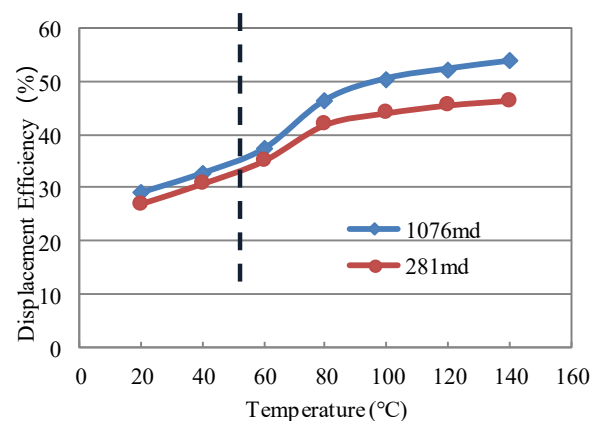


Figure 3. Oil recovery versus temperature.

Table 3. Oil recovery efficiency under different hot water temperatures (%).

Core	Temperature (°C)						
	20	40	60	80	100	120	140
A66-8	29.09	32.73	37.27	46.36	50.36	52.18	53.64
A66-5	27.06	30.79	35.09	41.82	44.00	45.45	46.36

From a purely laboratory perspective, 80 °C represents the upper range of effective thermal enhancement in the tested conditions and corresponds to the highest observed recovery level before the onset of obvious saturation in recovery improvement. However, when extending these results to field-scale application, the selection of injection temperature should not be based solely on maximum laboratory recovery, but should also consider the marginal benefit of additional heating relative to its energy cost.

In this context, although 80 °C provides a slightly higher recovery than 60 °C, the incremental improvement is relatively limited, whereas the required thermal energy input increases approximately linearly with temperature. Therefore, the efficiency of thermal utilization decreases significantly beyond 60 °C. Considering both displacement efficiency and economic efficiency, 60 °C is identified as a more balanced and practical injection temperature for field implementation in the A66 heavy oil reservoir.

Furthermore, recovery varies significantly with core permeability. Low-permeability cores (281 mD) exhibit lower recovery at all temperatures, and the difference between high- and low-permeability cores increases with temperature, highlighting the advantage of high-permeability reservoirs for fluid displacement.

Analysis of the relationship between injected pore volumes (PV) and recovery (Figure 4) indicates that recovery increases markedly up to about 1.5 PV, but stabilizes

beyond 6 PV, suggesting that additional injection in the late stage contributes little to further recovery.

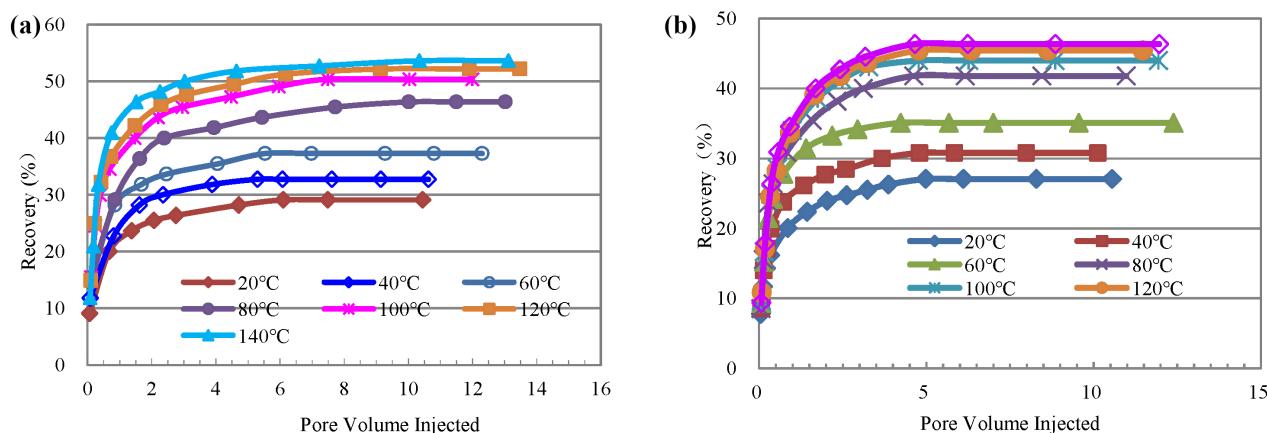


Figure 4. Oil recovery under different temperatures for (a) $K = 1076$ mD, (b) $K = 281$ mD.

In summary, injection temperature significantly influences heavy oil displacement. Moderate increases in temperature can substantially improve recovery, but excessively high temperatures offer limited additional benefit.

3.1.2. Injection Pressure and Pressure Gradient Measurement

To analyze the effect of temperature on injectivity, injection pressures and pressure gradients were measured in the two cores ($281 \times 10^{-3} \mu\text{m}^2$ and $1076 \times 10^{-3} \mu\text{m}^2$) under different temperatures. Results indicate that higher temperatures significantly reduce injection pressure, which is attributed to the reduction in oil viscosity and the corresponding decrease in flow resistance at elevated temperatures, thereby enhancing injectivity. All injection pressure measurements were repeated three times under identical experimental conditions, and highly consistent pressure–volume evolution trends were obtained, confirming good repeatability and measurement stability of the experiments.

In the high-permeability core (1076 mD), the pressure gradient decreases progressively with increasing temperature. The reported value of approximately 0.966 MPa/m at 80 °C corresponds to the stabilized stage of displacement, when the injected pore volume reaches approximately 1.0 PV and the pressure response has transitioned from the initial transient regime to a quasi-steady flow condition. At this stage, the influence of thermal front propagation and viscosity reduction has fully developed, and the pressure gradient reflects the system's stable injectivity. At lower temperatures (20–40 °C), the pressure increases continuously with injection volume, indicating greater flow resistance and a delayed establishment of a stable flow channel.

In the low-permeability core (281 mD), elevated temperatures also significantly reduce injection pressure; however, the overall pressure level remains higher than that of the high-permeability core under the same injection conditions, indicating that injectivity is strongly dependent on reservoir permeability.

During the early stage of displacement, the injection pressure initially increases with injected volume due to transient saturation redistribution. Subsequently, it decreases as thermal diffusion reduces oil viscosity and improves flow continuity. This behavior reflects the coupled effects of heat transfer and viscosity reduction during hot-water flooding. Figure 5a,b present the complete injection pressure evolution under different temperatures for both cores, showing that high-temperature conditions lead to more stable pressure responses and more favorable sustained injectivity performance.

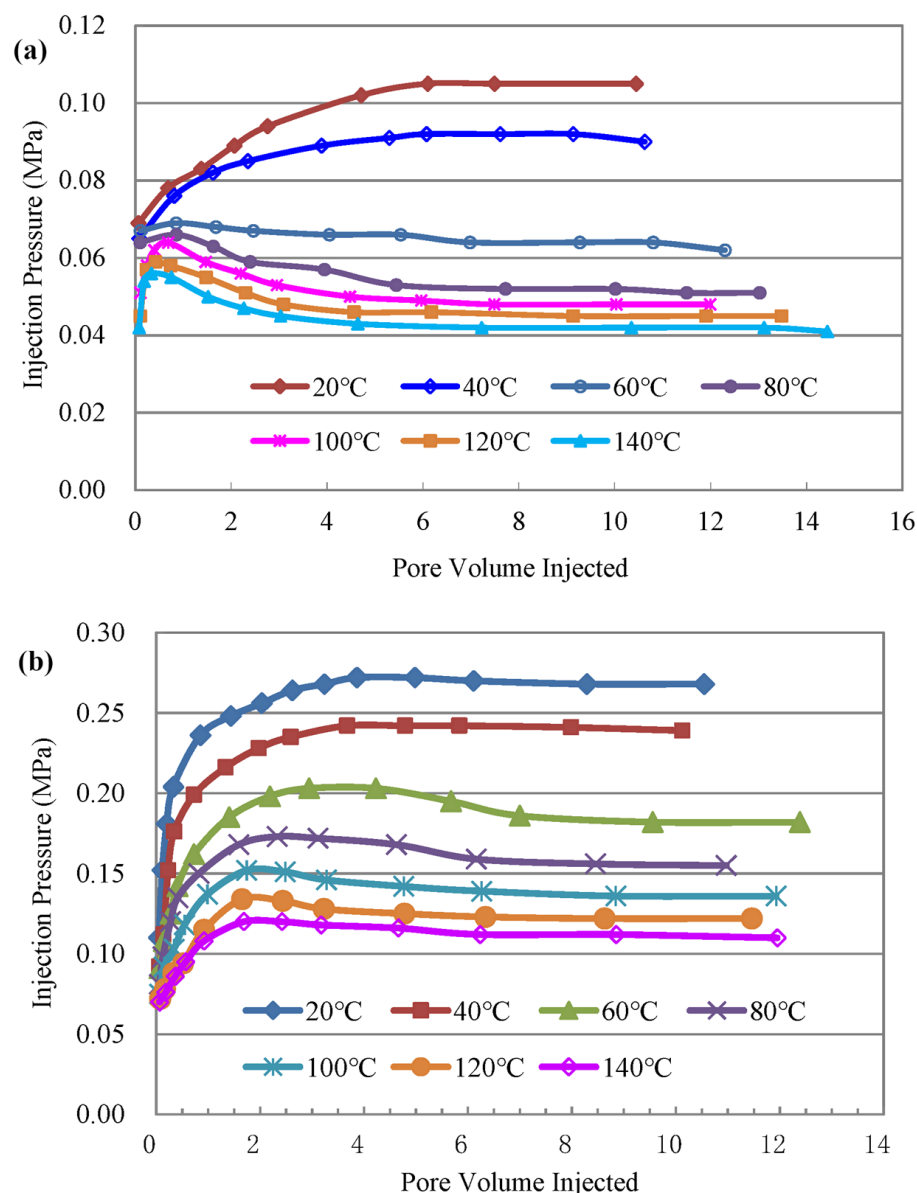


Figure 5. Injection pressure variation under different temperatures: (a) $K = 1076 \times 10^{-3} \mu\text{m}^2$, (b) $K = 281 \times 10^{-3} \mu\text{m}^2$.

3.1.3. Relative Permeability Measurements at Different Temperatures

Relative permeability is a key parameter describing multiphase flow in porous media and strongly affects displacement efficiency in heavy oil reservoirs. Pore structure, wettability, fluid properties, injection history, and temperature influence it.

The non-steady-state method (constant-rate injection) was used to determine oil–water relative permeability at 30 °C, 60 °C, and 90 °C, in accordance with industry standard SY/T 6315-2017 [32]. Three cores with similar permeability were tested (Table 4), and the data were processed using the J.B.N. method to generate relative permeability curves and water-cut–water-saturation relationships. Each relative permeability experiment at different temperatures was independently repeated three times, and the final curves were obtained by averaging the repeated measurements. The relative deviation among experimental runs was within $\pm 3\%$, indicating reliable and statistically consistent results.

Results (Figure 6) show that temperature significantly affects relative permeability curves. At 30 °C, the two-phase region is narrow, oil relative permeability declines rapidly, water relative permeability rises slowly, and water cut increases quickly, indicating rapid

progression to high-water stages and a short development cycle. At 60 °C, the two-phase region widens, water relative permeability rises faster, and water cut increases more slowly, suggesting a more stable displacement and an extended development cycle. At 90 °C, the two-phase region reaches its maximum, oil relative permeability declines more slowly, water relative permeability rises markedly, and water cut increases most gradually, indicating smoother displacement and a prolonged effective production phase.

Table 4. Core parameters for relative permeability tests.

Core	L (cm)	D (cm)	K _a (mD)	Φ (%)	T (°C)	μ _w (mPa·s)	S _{wi} (%)	S _{or} (%)	ED (%)
A66-11	8	2.5	881	31.9	30	0.68	29.9	40.6	42
A66-7	4.92	2.5	930	33.3	60	0.5	21.7	42.2	46
A66-7	4.92	2.5	930	33.3	90	0.47	19.2	40.1	50.4

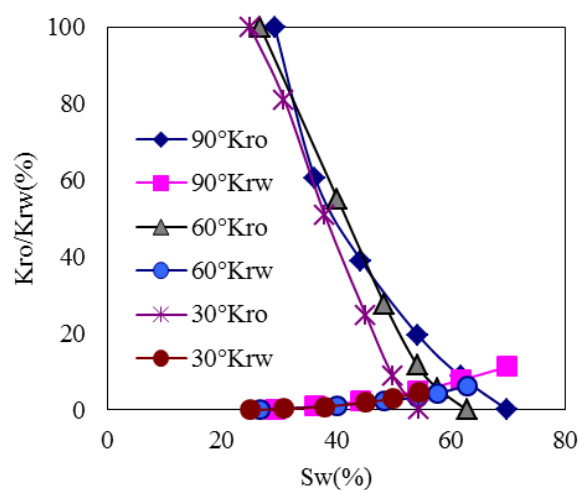


Figure 6. Oil–water relative permeability curves at different temperatures.

Overall, increasing temperature shifts relative permeability curves to the right, enhancing wettability toward water, reducing residual oil saturation, and significantly improving recovery. Mechanistically, high temperatures induce structural changes in polar components (colloids and asphaltenes) in heavy oil, weakening their adsorption on rock surfaces and increasing water film thickness in pores, forming stable flow channels. This “peeling effect” facilitates the mobilization of residual oil in dead-end pores (Figure 7).

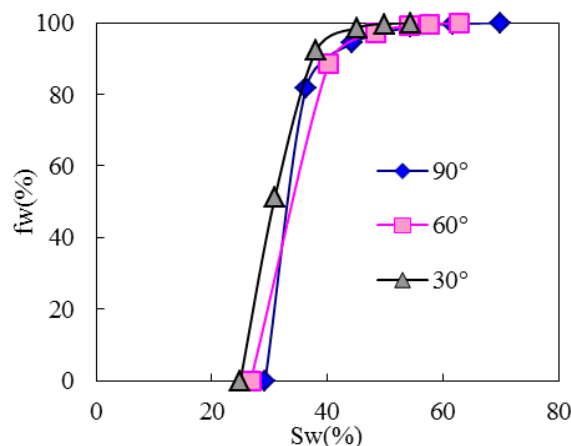


Figure 7. Water cut variation with water saturation at different temperatures.

3.2. Hot-Water Injection Method and Parameter Optimization for the A66 Block

Based on an understanding of the effects of temperature on heavy oil displacement, this study further investigates key engineering parameters in the hot-water injection process to optimize the development scheme for the A66 heavy oil reservoir. The effectiveness of hot-water flooding depends not only on temperature but also on injection volume, injection mode, and injection rate. Systematic laboratory simulations of these parameters are therefore crucial for improving recovery efficiency.

Using natural cores from the A66 block and field-sourced, degassed, and dehydrated crude oil, a series of hot-water flooding experiments was conducted to analyze the effects of different injection parameters. The experiments included optimization of injection volume, comparison of injection modes, and optimization of injection rate. Temperature, injection rate, and pressure were strictly controlled during the experiments to realistically simulate reservoir conditions and provide reliable guidance for field design.

3.2.1. Optimization of Hot-Water Injection Volume

The hot-water injection volume is one of the key parameters that affect the development performance of heavy oil reservoirs. An appropriate injection volume can not only improve oil displacement efficiency but also reduce ineffective circulation and enhance the economic performance of reservoir development. Therefore, in this study, laboratory displacement experiments were conducted to analyze the variation in hot-water flooding performance at different injection volumes, aiming to determine the optimal injection volume for the A66 block heavy oil reservoir.

In the experiments, hot water at 80 °C was used as the displacement medium. Four injection volumes—0.2 PV, 0.5 PV, 1.0 PV, and 1.5 PV—were designed for comparative analysis. During the experiments, the injection rate was maintained at 0.3 mL/min. A constant-temperature control system was employed to minimize heat loss before the injected hot water entered the core inlet, thereby ensuring that the experimental conditions could reasonably simulate the hot-water flooding process in actual reservoir development.

The experimental results are shown in Figure 8. As injected PV increased, the core's oil recovery generally increased. However, at 0.5 PV, a clear inflection point appeared in the oil recovery curve. Beyond this point, the rate of oil recovery slowed significantly as injection volume increased further. Meanwhile, the water cut curve gradually flattened. When the cumulative injection reached 2.2 PV, the water cut reached 98%, indicating that the hot-water flooding process can effectively delay the rapid increase in water cut and thus prolong the reservoir's effective production period.

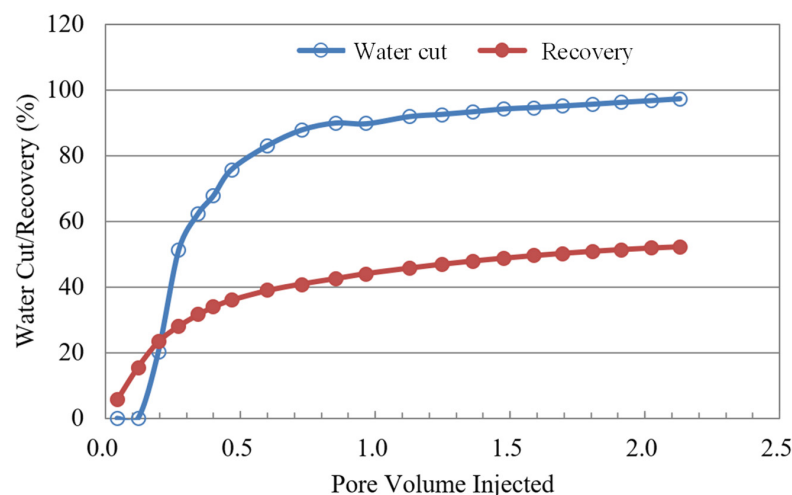


Figure 8. Variation in oil recovery and water cut with injected PV in the A66 block.

From the perspective of displacement mechanisms, during hot-water flooding, the injected hot water continuously exchanges heat with the crude oil in the core, significantly reducing the oil's viscosity. Meanwhile, the asphaltene and resin components in the heavy oil undergo structural changes and gradually disperse, thereby improving the oil–water flow conditions in the pore channels, enlarging the oil–water contact area, and increasing the sweep volume. When the injection volume is small, the thermal energy released by the hot water cannot be fully transferred throughout the core, resulting in a limited oil–water contact area and a relatively low displacement efficiency. Conversely, when the injection volume is excessively large, the surplus hot water tends to flow rapidly along already established preferential flow channels, leading to heat loss and reduced displacement efficiency for residual oil in marginal regions.

Therefore, an optimal injection volume typically exists during hot-water flooding. The experimental results indicate that for the A66 block heavy oil reservoir, an injection volume of 0.5 PV can achieve favorable oil displacement performance. Under these conditions, oil recovery can be significantly improved while reducing hot-water consumption and enhancing the overall economic efficiency of reservoir development.

To further clarify the rationale for selecting the recommended injection temperature, a technical–economic comparison between 60 °C and 80 °C is conducted. As shown in Table 7, increasing the injection temperature from 60 °C to 80 °C results in only a marginal improvement in final recovery factor (approximately 0.20–0.25%), indicating that the displacement efficiency has nearly reached a plateau in this temperature range.

However, from an energy consumption perspective, the heat input required to raise the injection temperature from 60 °C to 80 °C increases approximately in proportion to the temperature difference, resulting in a significantly higher thermal load and operational cost. Given that the viscosity of heavy oil decays exponentially with temperature, the incremental benefit of additional heating becomes progressively weaker at higher temperatures.

Therefore, the slight gain in recovery at 80 °C does not justify the substantially increased energy expenditure, especially under long-term field development conditions. This results in a clear diminishing marginal return, which makes 60 °C a more balanced and economically efficient choice for field implementation.

3.2.2. Determination of Injection Pressure and Pressure Gradient

In addition to injection volume, the injection mode of hot-water flooding can significantly influence heat distribution, mobility ratio, and oil–water flow characteristics during displacement. Therefore, this study designed several hot-water injection strategies to compare the effects of different injection modes on heavy oil displacement performance. Four injection schemes were used in the experiments: continuous injection, equal-cycle alternating injection, increasing-cycle injection, and decreasing-cycle injection. The specific designs of these schemes are presented in Table 5.

Table 5. Experimental schemes.

Scheme	Hot Water Temperature (°C)	Slug Combination Mode
Continuous injection	80	1.2 PV of 80 °C hot water
Equal-cycle injection	80/20	Alternating injection of 0.2 PV hot water/0.2 PV cold water
Increasing-cycle injection	80/20	Increasing sequence of 0.1 PV–0.3 PV hot water/cold water
Decreasing-cycle injection	80/20	Decreasing sequence of 0.3 PV–0.1 PV hot water/cold water

The results are summarized in Table 6. During the initial displacement stage (0–0.2 PV), the oil recovery of the four injection modes was nearly identical. This is mainly because,

at the early stage of displacement, a stable temperature field had not yet formed within the core. Therefore, the influence of injection mode on oil displacement performance was limited. However, when the injected volume exceeded 0.2 PV, differences among the injection schemes gradually became apparent.

Table 6. Oil recovery under different injection schemes (%).

Scheme	Cumulative Injection Volume			
	0.2 PV	0.4 PV	0.6 PV	1.2 PV
Continuous injection	23.23	33.85	38.84	46.54
Equal-cycle injection	23.57	28.55	32.70	38.67
Increasing-cycle injection	22.39	28.40	31.60	36.87
Decreasing-cycle injection	24.14	31.92	34.96	40.73

Overall, the continuous injection mode exhibited the best displacement performance. When the cumulative injection volume reached 1.2 PV, oil recovery under continuous injection was significantly higher than that of the other three schemes, with improvements ranging from 5.81% to 9.67%. This result indicates that a continuous, stable heat supply during the hot-water flooding process is more favorable for maintaining the reservoir temperature field, thereby preserving the low-viscosity state of crude oil and improving displacement efficiency.

The decreasing-cycle injection scheme ranked second in displacement performance. This is mainly because injecting a relatively large slug of hot water during the early stage of displacement can rapidly increase the core temperature and reduce crude oil viscosity, thereby establishing favorable flow conditions. In contrast, the increasing-cycle injection scheme showed the poorest displacement performance. The primary reason is that the injected hot water volume in the early stage is relatively small, resulting in limited temperature increase and an insignificant viscosity-reduction effect. Meanwhile, the unfavorable mobility ratio may promote viscous fingering along the main flow channels, causing subsequently injected hot water to flow rapidly through preferential channels and reducing the displacement efficiency of residual oil.

In addition, periodic injection of cold water in the equal-cycle scheme reduces core temperature, increases crude oil viscosity, and reduces displacement efficiency. Therefore, for the development of the A66 block heavy oil reservoir, continuous hot-water injection is more beneficial for improving oil recovery.

3.2.3. Optimization of Hot-Water Flooding Injection Rate

Displacement rate is another important factor affecting the development performance of heavy oil reservoirs. A reasonable injection rate can improve displacement efficiency and enlarge the sweep volume of oil and water; however, excessively high or low injection rates may reduce oil recovery efficiency. Therefore, this study experimentally analyzed the variation in water-flooding recovery at different injection rates to determine the optimal injection rate.

The experiment employed an artificial homogeneous core model measuring 30 cm × 4.5 cm × 4.5 cm. The displacement fluid was a simulated oil prepared by mixing degassed, dehydrated field crude oil with aviation kerosene in a specified proportion, ensuring that the fluid properties closely matched those of actual reservoir conditions. The experimental results are shown in Figure 9. As the injection rate increased, water flooding recovery generally increased, rising from 58.94% to 64.80%. However, the recovery growth rate showed a clear pattern of rapid increase followed by gradual stabilization.

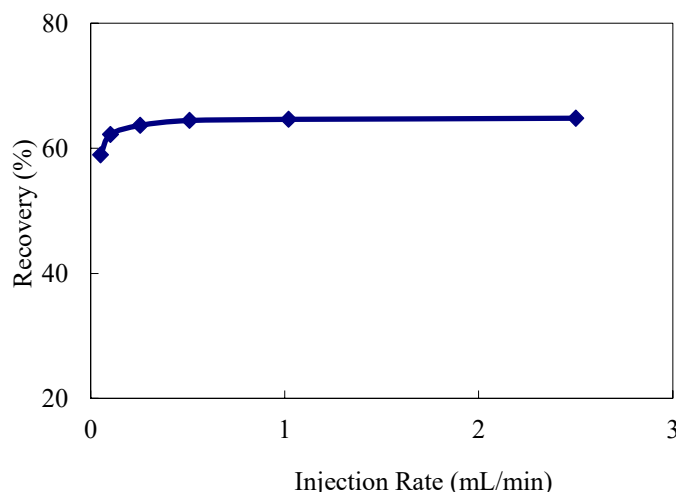


Figure 9. Relationship between homogeneous water flooding recovery and injection rate.

At low injection rates, a moderate pressure gradient facilitates the entry of the displacement fluid into small pore spaces, thereby increasing the oil–water contact area and improving the displacement of residual oil in micropores. As the injection rate increases, both the capillary number and the pressure gradient during displacement increase accordingly, helping overcome capillary forces and enhancing the mobilization of crude oil trapped in micropores. However, when the injection rate exceeds 0.051 m/d, recovery rate increases significantly. This is mainly because, under high injection rates, the displacement fluid tends to advance rapidly along established preferential flow channels, intensifying water channeling and forming ineffective circulation, thereby reducing overall oil displacement efficiency.

Therefore, from the perspective of displacement mechanisms, the injection rate has a dual influence on oil displacement efficiency: increasing it appropriately can enhance the pressure gradient and improve displacement efficiency, whereas excessively high rates may reduce sweep volume and induce short-circuiting. The experimental results indicate that, under the conditions of this study, 0.051 m/d is the optimal injection rate for hot-water flooding in the A66 block heavy oil reservoir.

By integrating the optimization results of hot-water injection volume, injection mode, and injection rate, several conclusions can be drawn. First, an optimal injection volume exists during hot-water flooding, and 0.5 PV can achieve favorable oil displacement performance. Second, continuous hot-water injection can maintain a stable temperature field and improve crude oil mobility, resulting in significantly better displacement performance than alternating injection schemes. Third, the injection rate has a dual influence on oil displacement efficiency, and under the conditions of this study, 0.051 m/d represents the optimal injection rate. Overall, by optimizing hot-water flooding injection parameters, the development efficiency of the A66 block heavy oil reservoir can be significantly improved. These findings provide important experimental support for the design of hot-water flooding development schemes for the A66 block heavy oil reservoir.

3.3. Study on the Conversion Strategy of Hot-Water Flooding in the A66 Block

Based on previous experimental studies, it has been confirmed that hot-water flooding can significantly reduce heavy oil viscosity and improve oil displacement efficiency. However, in actual field development, long-term continuous injection of high-temperature hot water not only results in high energy consumption but may also lead to heat loss and increased development costs. Therefore, during the hot-water flooding process, it is

important to reasonably determine the displacement medium temperature, the timing of injection conversion, and the injection parameters to improve development efficiency while reducing production costs.

To address this issue, this study further integrates numerical simulation and techno-economic evaluation based on laboratory experiments to systematically investigate the effects of different displacement medium temperatures, the timing of hot-water injection conversion, and injection schemes on the development performance of the A66 block heavy oil reservoir. By comparing multiple development scenarios, the study aims to provide a more scientific and practical technical basis for field reservoir development.

The numerical simulation model was developed based on geological interpretation data, well logging information, and laboratory measurements of reservoir rock and fluid properties from the A66 block. The model represents a typical injection–production well pattern unit and is used to simulate the thermal and fluid-flow behavior of heavy oil reservoirs under different development scenarios. The simulation framework employs a fully coupled thermal reservoir model, enabling the simultaneous calculation of multiphase flow and heat transfer processes.

A three-dimensional structured grid system was adopted in the numerical model. The grid was refined near injection and production wells to accurately capture steep gradients in pressure, temperature, and saturation. In contrast, coarser grids were used in the outer region to improve computational efficiency. Reservoir heterogeneity was represented by spatial distributions of porosity and permeability derived from geological interpretation and core analysis.

The reservoir fluid was modeled as a temperature-dependent heavy oil system. The viscosity of crude oil decreases exponentially with increasing temperature, based on laboratory-measured rheological data. Relative permeability curves for the oil–water system were obtained from core flooding experiments and used to describe multiphase flow behavior under different saturation conditions. Thermal processes in the model include conductive heat transfer within the rock matrix and convective heat transfer associated with fluid flow. The thermal coupling between the rock and fluid phases was fully accounted for to capture the temperature evolution during hot-water flooding and subsequent cold-water injection.

Prior to scenario simulations, a history-matching procedure was performed to ensure the reliability of the numerical model. The calibration process involved adjusting key uncertain parameters, including permeability distribution and relative permeability characteristics, to match historical production data such as oil production rate, water cut, and cumulative oil production. After calibration, the simulation results showed good agreement with field production trends, confirming that the numerical model is sufficiently reliable for predictive scenario analysis and subsequent optimization studies.

Based on the validated numerical simulation model, all subsequent scenario analyses were conducted under identical reservoir and fluid conditions, ensuring that differences in the simulation results were solely attributable to changes in injection strategy and operating parameters.

3.3.1. Optimization of Displacement Medium Temperature

The temperature of the displacement medium is one of the key factors affecting the development performance of hot-water flooding. Appropriate selection of injection water temperature can not only enhance crude oil mobility but also effectively control development costs. Therefore, in this study, factors such as reservoir heat loss, formation pressure variation, temperature field distribution, and displacement characteristics were comprehensively considered. Numerical simulation was used to evaluate development

performance under different injection temperatures. All simulations at different injection temperatures were conducted using the same calibrated reservoir model described in Section 3.3, ensuring consistent comparison.

The injection–production system is constrained by constant injection rate control for injection wells and bottom-hole pressure constraints for production wells, consistent with field operation conditions. The outer boundaries of the simulation domain are treated as no-flow boundaries, assuming that the modeled area represents a closed well-pattern development unit. Initial reservoir pressure and temperature conditions are set based on field measurements from the A66 block.

In the simulation, injection water temperatures were set to 20 °C, 40 °C, 60 °C, 80 °C, and 100 °C, with the injection rate maintained at 20 m³/d. The injection–production balance condition was preserved, and the maximum wellhead injection pressure was limited to 15 MPa. In addition, to more realistically reflect the influence of reservoir temperature variations on seepage characteristics, the model accounts for cold-damage effects through a coupled temperature-dependent viscosity formulation and a permeability-reduction coefficient, enabling a quantitative representation of both reversible thermal effects and irreversible formation damage induced by low-temperature injection.

Cold-damage effects in this study are defined as reductions in oil mobility and flow capacity induced by reservoir cooling during low-temperature water injection. The physical origin of this phenomenon primarily involves two mechanisms: the exponential increase in crude oil viscosity with decreasing temperature and the reduction in oil-phase relative permeability due to wax and asphaltene precipitation and pore-throat blockage.

In the numerical model, the temperature-dependent viscosity is expressed using an Arrhenius-type relationship:

$$\mu(T) = \mu_{\text{ref}} \cdot \exp[\alpha(T_{\text{ref}} - T)], \quad (3)$$

where μ_{ref} is the reference viscosity at reservoir temperature T_{ref} , and α is the viscosity–temperature sensitivity coefficient obtained from laboratory rheological measurements.

The irreversible part of cold damage is represented using a permeability reduction formulation:

$$k_r = k_{r0} \cdot (1 - D), \quad (4)$$

where k_{r0} is the original relative permeability, and D is the cold-damage coefficient, which increases when the reservoir temperature drops below the wax appearance temperature and partially remains after reheating to represent irreversible formation damage.

Table 7 presents the production performance indicators for different displacement medium temperatures, with and without cold damage effects. The indicators include water cut, oil recovery factor, cumulative recovery after 5, 10, and 20 years of production, and the final recovery factor at 95% water cut.

The simulation results indicate that when the cold damage effect is considered, the development performance of cold-water flooding is significantly poorer than that of hot-water flooding. During cold-water flooding, a decrease in reservoir temperature increases crude oil viscosity and reduces oil-phase permeability, resulting in lower cumulative oil production and a more rapid rise in water cut. When the cold-damage effect is not considered, the difference between cold-water flooding and hot-water flooding becomes relatively smaller; however, hot-water flooding still shows better development performance as the injection temperature increases.

Overall, variations in cumulative oil production and final recovery factor across different temperature conditions are not very significant, but increasing temperature can markedly improve oil–water flow conditions. Higher temperatures not only reduce crude

oil viscosity but also expand the displacement sweep volume, thereby optimizing the two-phase flow behavior of oil and water.

From the perspective of staged production performance, when the injection water temperature increases from 40 °C to 60 °C, the net oil production increases most significantly. However, as the temperature increases further to 80 °C and 100 °C, the increase in oil production gradually decreases. This phenomenon is mainly attributed to the diminishing marginal effect of temperature on viscosity reduction. At lower temperatures, increasing temperature significantly reduces crude oil viscosity, whereas at higher temperatures, the viscosity reduction becomes less pronounced, resulting in a smaller improvement in oil displacement efficiency.

Considering both reservoir development performance and economic efficiency, excessive injection temperatures are not recommended because the incremental improvement in oil recovery gradually diminishes at higher temperatures, whereas thermal energy consumption and operating costs increase significantly. Therefore, an injection temperature of approximately 60 °C is recommended during the early development stage of the A66 heavy oil reservoir.

Therefore, a reasonable selection of hot-water injection temperature can not only improve the oil recovery factor but also effectively delay the rise in water cut, thereby enhancing the overall economic performance of field development.

Table 7. Statistical results of displacement medium optimization.

Category	Displacement Medium		5 Years		10 Years		20 Years		Water Cut = 95%	
	Medium	Temperature (°C)	Water Cut (%)	Recovery (%)	Water Cut (%)	Recovery (%)	Water Cut (%)	Recovery (%)	Injection Ratio	Final Recovery (%)
Considering cold damage	Cold water	40	32.46	3.25	47.80	7.96	76.15	13.40	0.674	21.45
		50	30.84	4.22	46.75	9.03	74.10	14.78	0.683	23.27
	Hot water	60	28.35	5.35	47.97	10.19	74.40	15.82	0.693	24.39
		80	28.33	5.35	47.87	10.19	74.24	15.85	0.693	24.59
		100	28.30	5.35	47.63	10.20	73.89	15.90	0.704	25.09
Not considering cold damage	Cold water	40	26.58	3.53	40.18	8.80	71.63	15.19	0.674	24.33
		50	27.30	4.44	44.12	9.52	73.11	15.51	0.683	24.37
	Hot water	60	28.35	5.35	47.97	10.19	74.40	15.82	0.693	24.39
		80	28.33	5.35	47.87	10.19	74.24	15.85	0.693	24.59
		100	28.30	5.35	47.63	10.20	73.89	15.90	0.704	25.09

Note: The water flooding recovery factor refers to the recovery degree when the water cut reaches 95%. The pore volume of the injection–production well pattern control area is $286.6 \times 10^4 \text{ m}^3$.

3.3.2. Study on the Timing of Conversion in Hot-Water Flooding

During hot-water flooding development, as the cumulative injection volume reaches a certain level, the oil displacement efficiency of hot water tends to decline gradually. At this point, continued injection of high-temperature hot water contributes little to further improving the recovery factor, and its primary function shifts to maintaining reservoir driving pressure. Therefore, converting hot-water flooding to low-temperature flooding at the appropriate time can maintain displacement pressure while reducing development costs.

Based on the analysis of the relationship between injection pore volume multiples and oil displacement efficiency under different displacement media conditions, it is observed that once the injected pore volume exceeds a certain threshold, the utilization efficiency of injected water decreases significantly. Accordingly, this study proposes that after injecting 60 °C hot water for a certain period, the injection medium should gradually be converted to lower-temperature water or produced water to optimize development costs.

When adopting alternating injection of hot water and cold water slugs, the high wax appearance temperature characteristics of heavy oil reservoirs and the influence of temperature variation on oil-phase permeability must also be considered. Experimental and numerical simulation results indicate that when the reservoir temperature decreases, the oil-phase permeability declines significantly. Although some of the permeability can be restored after reheating, irreversible damage may still occur. Therefore, to avoid the formation of local low-temperature zones and potential cold damage caused by frequent injection of low-temperature fluids, it is recommended that 60 °C hot-water flooding be implemented in the early stage of development, followed by a gradual conversion to 40 °C cold water or lower-temperature hot water after the reservoir water cut reaches a certain level.

Table 8 lists the simulation results of injection–production well patterns under different conversion timing scenarios. The analysis shows that the timing of conversion has a relatively small impact on the final recovery factor, and the production curves of different schemes are generally similar. Delaying the conversion time slightly increases the final recovery factor, but the overall difference remains limited. This phenomenon is mainly related to the relatively high original formation temperature of the A66 reservoir. After low-temperature fluids are injected into the reservoir, strong heat exchange with the formation allows the local temperature to recover relatively quickly, thereby limiting the influence on displacement efficiency.

Table 8. Statistical results of optimal timing for displacement medium conversion.

Injection Scheme	Conversion Timing	60 °C Hot Water Stage		40 °C Cold Water Stage		Total		
		Injection Ratio	Recovery (%)	Injection Ratio	Recovery (%)	Injection Ratio	Recovery (%)	Development Period (Years)
60 °C hot water → 40 °C cold water	No conversion	0.693	24.39	/	/	0.693	24.39	56
	fw = 10%	0.007	0.81	0.496	20.64	0.693	24.23	52
	fw = 30%	0.057	5.71	0.446	15.76	0.693	24.30	54
	fw = 50%	0.108	9.83	0.395	11.63	0.693	24.31	55
	fw = 70%	0.165	13.05	0.338	8.50	0.693	24.35	56
	fw = 90%	0.390	19.46	0.113	1.83	0.693	24.37	56

Note: The water flooding recovery factor refers to the recovery degree when the water cut reaches 95%. The pore volume of the injection–production well pattern control area is $286.6 \times 10^4 \text{ m}^3$.

Considering both development stability and economic performance, this study recommends implementing the hot-water flooding conversion strategy when the water cut reaches approximately 10–20%. This approach can ensure development effectiveness while reducing the cost of continuous hot-water injection.

3.3.3. Optimization of Hot-Water Flooding Injection Parameters

In addition to displacement temperature and conversion timing, an appropriate injection scheme is also a key factor affecting reservoir development performance. The injection scheme primarily includes parameters such as production rate, injection–production ratio, and water-injection mode. A reasonable production rate should not only meet field production requirements but also consider the reservoir pressure-bearing capacity and the formation's seepage characteristics. Generally, the injection–production ratio should be maintained at 1.0 or slightly higher to ensure a stable fluid supply to production wells.

In this study, a development scheme was adopted in which 60 °C hot-water flooding was applied until the water cut reached 10%, followed by conversion to 40 °C cold-water injection, with an injection–production ratio of 1.0. Meanwhile, the development perfor-

mance under stable water injection and unstable water injection modes was compared and analyzed.

The unstable water injection mode periodically adjusts the injection intensity across different injection wells, causing the displacement fluid's flow direction within the reservoir to change continuously, thereby improving areal sweep efficiency. In addition, during the periodic pressure-increase stage, low-permeability layers can be activated, thereby improving vertical sweep efficiency.

Table 9 presents the simulation results for different water-injection modes. The analysis shows that under similar cumulative oil production conditions, unstable water injection schemes exhibit lower overall water cuts and better development performance than stable water injection schemes. Particularly in the late stage of development, adopting unstable water-injection schemes with larger injection-volume fluctuations can effectively enhance displacement pressure and activate low-permeability reservoirs, thereby expanding the water-flooding sweep area and further improving the recovery factor.

Table 9. Statistical results of optimal water injection schemes.

Injection–Production Scheme			10 Years		20 Years		30 Years		Water Cut = 95%	
Water Injection Mode	Daily Oil Production per Well	Production Rate (%)	Water Cut (%)	Recovery (%)	Water Cut (%)	Recovery (%)	Water Cut (%)	Recovery (%)	Injection Ratio	Final Recovery (%)
Stable injection	8.52	0.57	59.85	12.07	83.80	18.42	91.26	21.58	0.927	25.44
Unstable injection-I	7.67	0.50	59.85	12.07	83.32	17.18	89.41	19.97	0.919	25.45
Unstable injection-II	8.27	0.55	59.85	12.07	83.70	18.41	90.46	21.71	0.919	25.48
Unstable injection-III	8.27	0.55	59.85	12.07	83.80	18.42	90.43	21.72	0.922	25.54
Unstable injection-IV	8.26	0.55	59.85	12.07	83.80	18.42	90.52	21.73	0.922	25.62

3.3.4. Techno-Economic Evaluation of Development Strategies

To further evaluate the feasibility of the proposed hot-water flooding strategy, a comprehensive techno-economic evaluation was conducted for different development methods, including cold-water flooding, hot-water flooding, and steam-assisted recovery processes. The objective of this analysis is to quantify the trade-off between incremental oil recovery and associated capital and operating costs under different development scenarios, thereby providing a basis for engineering decision-making.

The economic evaluation is based on a discounted cash flow (DCF) framework with a 10-year production period. The economic indicators, including net present value (NPV), internal rate of return (IRR), and payback period, are calculated using annual net cash flow after taxation. Cash flow is calculated by subtracting capital expenditures (CAPEX), operating expenditures (OPEX), and taxes from oil revenue.

Oil price scenarios are set at 50, 60, and 80 USD/bbl (pre-tax), consistent with regional petroleum economic evaluation standards. Other economic parameters follow the A66 block engineering-economic evaluation database. Although a fixed discount rate is embedded in the evaluation system, the relative comparison between development schemes is not sensitive to small variations in discount rate assumptions, as all scenarios are evaluated under identical economic conditions.

Capital expenditures include drilling investment, surface facility construction, and thermal system infrastructure. Drilling costs are differentiated between vertical wells (114.8×10^4 CNY/well) and horizontal wells (611.88×10^4 CNY/well), while surface facility investment is taken as 166.55×10^4 CNY per well. For hot-water flooding systems, additional surface facilities are required, including heating furnaces, water treatment

systems, storage tanks, pipeline networks, and thermal insulation systems, leading to incremental infrastructure investment.

Operating expenditures consist of well operation costs and energy consumption costs associated with fluid heating and injection. In particular, the incremental cost of hot-water injection is calculated based on field-measured energy consumption parameters. Heating 1 ton of water from 5 °C to 100 °C requires approximately 12 m³ of natural gas. With a natural gas price of 0.98 CNY/m³, the heating cost is 11.76 CNY/t. In addition, pumping and circulation systems consume approximately 300 kWh/day of electricity per system, corresponding to an annual cost of approximately 6.91×10^4 CNY. Combining all operating components, the total incremental cost of hot-water injection is estimated as 20.6 CNY/t of injected water. The additional production cost is set at 3.5×10^4 CNY per well per year.

Based on the above cost structure and production profiles obtained from reservoir simulation, annual cash flow is calculated for each development scheme. The cumulative discounted cash flow is then used to determine IRR, NPV, and payback period.

Simulation results indicate that steam-assisted recovery exhibits the highest early-stage oil production; however, its high capital investment and thermal energy consumption significantly reduce its economic competitiveness. Cold-water flooding shows lower recovery efficiency and limited revenue generation. In contrast, hot-water flooding provides a balanced performance between incremental oil recovery and operating costs.

As shown in Table 10, when the oil price is 60 USD/bbl, the after-tax IRR of the hot-water flooding scheme is 22.97%, with a payback period of 3.21 years. At oil prices of 50 and 80 USD/bbl, IRR decreases and increases accordingly, demonstrating expected sensitivity to oil price fluctuations while maintaining overall economic robustness.

Table 10. Techno-economic evaluation results of hot-water flooding with viscosity reducer in the A66 block.

Oil Price (USD/bbl)	Before Tax			After Tax		
	Net Profit (10 ⁴ CNY)	Internal Rate of Return (%)	Payback Period (Years)	Net Profit (10 ⁴ CNY)	Internal Rate of Return (%)	Payback Period (Years)
50	639.67	14.69	3.75	/	5.6	4.69
60	3693.81	43.82	2.52	1559.26	22.97	3.21
80	12,949.25	179.81	1.5	8757.8	83.19	1.96

Overall, although steam flooding achieves higher recovery in early stages, its economic performance is limited by high energy demand and infrastructure costs. Hot-water flooding, therefore, represents the most balanced and economically feasible development strategy for the A66 heavy oil reservoir under the given geological and operational conditions.

A further integrated evaluation combining recovery performance and thermal energy consumption confirms that the marginal benefit of increasing injection temperature decreases rapidly beyond 60 °C. Considering both recovery efficiency and energy input, the 60 °C scenario provides the highest overall energy utilization efficiency, while higher temperatures result in disproportionately increased thermal costs with limited additional production gain. Therefore, 60 °C is identified as the optimal operational condition from a techno-economic perspective.

4. Conclusions

This study develops a comprehensive optimization framework for hot-water flooding and subsequent injection conversion in heavy oil reservoirs, focusing on the coupled effects of displacement fluid temperature, injection transition timing, and injection mode. The proposed approach integrates laboratory experiments, numerical simulations, and

techno-economic analysis to evaluate development performance and economic feasibility systematically.

The results indicate that injection temperature plays a critical role in determining oil displacement efficiency. Increasing the injection temperature significantly reduces crude oil viscosity and improves mobility, with the most pronounced improvement observed when the temperature increases from 40 °C to 60 °C. However, further increases in temperature result in diminishing marginal improvements, indicating that excessively high thermal input does not proportionally enhance recovery performance. From both technical and economic considerations, an injection temperature of approximately 60 °C is identified as the optimal condition for early-stage development.

The study further reveals that the timing of conversion from hot-water flooding to low-temperature water injection has a limited influence on the ultimate recovery factor but a significant impact on operational costs and thermal efficiency. This is attributed to the relatively rapid thermal equilibration between the injected fluid and the reservoir formation, which reduces the long-term impact of injection temperature on displacement behavior. Based on this mechanism, a transition strategy at a water cut of approximately 10–20% is recommended to balance thermal efficiency and cost reduction while mitigating potential cold-damage effects associated with abrupt temperature changes.

In addition, unstable water injection is shown to significantly improve sweep efficiency by dynamically adjusting injection intensity and flow paths, thereby enhancing both areal and vertical displacement performance compared with stable injection schemes under equivalent injection volumes.

Importantly, the main contribution of this study is not only the optimization of individual parameters but also the establishment of a coupled hot-to-cold water injection conversion strategy as a unified development framework. This strategy integrates thermal recovery, reservoir flow evolution, and economic evaluation, enabling a coordinated optimization of recovery enhancement and cost control. Compared with conventional cold-water flooding and continuous hot-water flooding, the proposed strategy achieves a superior balance between technical performance and economic feasibility.

Overall, the integrated optimization of injection temperature, conversion timing, and injection scheme provides a practical and field-applicable development methodology for heavy oil reservoirs. The findings of this study can serve as a useful reference for the efficient and economical development of similar heavy oil resources.

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