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COMPUTATIONAL ANALYSIS OF GEOTHERMA-ENHANCED HEAVY OIL PRODUCTION

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Abstract

This study seeks to research the incorporation of geothermal energy with steam injection for better recovery of heavy oil in offshore and thermally challenging reservoirs. The goal is to determine the effects of steam temperature, well spacing, and oil mobility on reservoir pressure and energy efficiency in long-term production supply scenarios. A comprehensive numerical simulation approach was applied utilizing CMG-STARS software to simulate Enhanced Geothermal Systems (EGS) with steam injection. The case study relied on Bohai NB35-2S offshore heavy oil reservoir. A number of operational parameters were tested: steam temperatures of 150°C, 200°C, and 250°C, along with well distances of 100m, 150m, and 200m. These were analyzed for their impact on oil recovery, pressure changes during production, and production stability over a simulated period of 10 years. The results indicate increased temperatures did lower oil viscosity and short-term daily oil production rates; however, these outcomes did not influence cumulative oil production. Lower temperatures (especially 150°C) sustained bottom-hole pressures and provided longer production phases, especially at closer well spacing. Wider well configurations had higher heat loss, unstable pressure, and reduced effectiveness. During sensitivity analysis, higher temperatures also increased steam-oil ratio (SOR) with operational risk, which limits long-term sustainability.

Optimal recovery was reached with a leveled moderate thermal input and compact well spacing. It presents a new hybrid geothermal-steam recovery model that addresses the particular difficulties posed by offshore heavy oil reservoirs. By integrating considerations of thermal efficiency with spatial arrangement, the research provides a valuable guideline for the design of energy-efficient and operationally resilient oil recovery systems. It contributes to the operational needs of field engineers and energy strategists in the context of enduring enhanced oil recovery (EOR) implementation.

Keywords: Geothermal energy, Steam injection, Heavy oil recovery, Reservoir simulation, Enhanced oil recovery (EOR)

I. INTRODUCTION

The unexploited reserves of heavy oil and bitumen represent a significant global resource, with estimated reserves of nearly 10 trillion barrels, three times the volume of conventional oil [18]. The increasing demand for these resources has contributed significantly to the rising global production of heavy oil. Conventional cold production methods, such as wormhole formation and foamy oil recovery, have been partially effective in extracting heavy oil. However, these techniques alone are insufficient due to the high viscosity of heavy oil, which severely limits mobility and recovery efficiency [2].

Thermal recovery methods shift the viscous flow barrier and increase recovery flow rate, effectively making them an optimal choice [13]. In addition, in Canada alone, cyclic steam stimulation in single wells has increased recovery by an additional 10-15%. Cold lake is reported to reach over 25% recovery with projection aiming for 35%. Moreover, steam flooding has the ability to recover over 30% of the original oil in various reservoirs containing oil and 1000 mPa.s oil viscosity [5]. There are other efficient techniques such as in-situ combustion. Although, SAGD is commonly known to have above 20 meters thick reservoir requirements. Nevertheless, numerous reservoirs like the one studied here with thickness between 5 and 16 meters show a broader application scope for PEG which makes them more relevant to the discussed context [8].

Although offshore fields contribute significantly to the global energy supply, the conventional offshore reserves remain predominant [14]. For example, China's Bohai offshore field has OOIP (oil resources) with approximately 85% being heavy oil. Unfortunately, oil viscosities exceeding 350 mPa.s renders production multilateral wells and cold sand production methods rather ineffective [17]. Operational data indicates that there is low single well efficiency and low recovery rates. Furthermore, previous attempts at recovery were hampered by high operational costs and the short life span of platform wells [19].

A. Introduction to EGS Steam Flooding Technology

As with, new strategies to increase the recovery factor of heavy oil offshore fields are needed. One possible approach to recovering offshore fields is through the application of Enhanced Geothermal Systems (EGS) which offer compact, high-efficiency heat sources suitable for constrained offshore platforms [15]. In this study, the hypothesis of using EGS for heavy oil recovery is tested by injecting steam generated from EGS into submerged heavy oil reservoirs, thereby enabling thermal recovery alongside energy generation [20].

II. METHODOLOGY

This study applies steam injection into Enhanced Geothermal Systems (EGS) using numerical simulation to assess the recovery of heavy oil from reservoirs. The study aims to evaluate how operational parameters such as injection temperature, well spacing, recovery, and energy efficiency could be improved.

For the purpose of detailed quantitative assessment, the CMG-STARS simulation developed by the Computer Modeling Group was utilized. This sophisticated software can simulate dynamic thermal and multiphase fluid flow processes within a reservoir. The simulation was applied to the Bohai NB35-2S heavy oil reservoir, taking into consideration relevant geological engineering data which included the reservoir depth (1100 meters), thickness (5-to-16 meters), porosity (30%), and initial oil viscosity (828 mPa·s at room temperature). These physical parameters were chosen to ensure accuracy and fidelity to actual field conditions.

In this grid model, temperature distribution, oil saturation, and fluid movement as a result of steam injection into the reservoir was simulated. Recovery performance was examined across spacing of 100m, 150m, and 200m between wells.

To assess the effect of thermal energy on the mobility of oil, steam injection was simulated at 150°C, 200°C, and 250°C. The simulations aimed to evaluate the changes in oil viscosity, bottom-hole pressure, and the volume of oil produced sequentially with steam injection over time. Continuous steam injection was done while capturing key performance indicators, which included daily oil production rates along with saturation profiles at various intervals [23].

The sensitivity analysis helped in determining the optimal temperature and spacing combinations, which resulted in the maximum oil recovery with minimum energy consumption. This integrated method allows for a complete evaluation of geothermal-steam-assisted oil recovery and the formulation of robust methods for heavy oil fields located both onshore and offshore.

A. Numerical Simulation Model

In this regards, to the numerical evaluation of processes involving geothermal-assistance steam injection, the STARS software by Computer Modeling Group was applied. A thermal fluid system containing heat transfer as well as fluid flow during steam flooding was modeled in 3D and three phases [16]. The model is particularly appropriate for the Bohai NB35-2S heavy oil reservoir, considering factors such as reservoir depth, permeability, porosity, and formation temperature [9]. To design the grid system, actual geological contours of Bohai NB35-2S reservoir were taken into account. Other essential input parameters, including reservoir depth (1100m), thickness (5-16m) and porosity (30%), were incorporated into the model. The reservoir pressure is 7MPa, and the temperature is 70 °C. The reservoir is characterized by an initial oil viscosity of 828m-Pa·s at room temperature; however, it decreases substantially with increasing temperature. This enables efficient steam injection for oil recovery.

B. Experimental Setup and Reservoir Properties

The purpose of the simulation model was to determine the effect of different well spacing on the efficiency of heavy oil recovery. In this regard, three distances were experimentally set at 100 meters, 150 meters, and 200 meters for both the injection and production wells along the wellbore. In addition, three steam injection temperatures of 150°C, 200°C, and 250°C were used to evaluate their effects towards recovering oil by reducing its viscosity [10].

This describes the purpose of this assessment of Schemes IV, C, and D along with including illustrations [12]. Schemes A and B are not necessary to Duplication purpose. As a result of the duplicate processes the outcome will not be any first primary result injection crude oil directly into the producing steam well.

The simulation makes use of software that computes continuously thermomechanical processes presented in the enclosure to the reservoir model. The enclosing reservoirs model contains poles temperature under the shell linking ducts surfaces, which are artificially kept steady by means of positive controls. These walls are purposed to refrains heat exchange with the external environment enabling analyzing as in bypass a star chamber. The software dynamically computes and systematically analyzes a multitude of countless possible designs aimed at satisfying the user's expectations that can also preclude being excludable due to their designation.

C. Steam Injection Process

For the steam flooding methodology, different extraction rates and temperatures from 150°C to 250°C were tested to find the optimum thermal condition set for oil extraction and energy consumption [7]. Thermal oil recovery was evaluated by measuring the change of temperature-injected oil effects for viscosity, pressure, and extraction efficiency. The focus remained on finding an optimal thermal condition for maximum oil output and reduced energy expenditure [22].

Using thermal and hydraulic simulations, the study set 100 m, 150 m, and 200 m as the distances between pedicle pump injectors and other production injectors. This analysis was concerned primarily with performance recovery sensitivity for well spacing. Testing these distances assisted determine the optimal parameters for interwell distances and oil recovery factors, as well as thermal energy recovery [21].

Moreover, this analysis was aimed at establishing boundary conditions for SOR and bottom-hole pressure of the production wells, in order to determine the precise impact of changing steam temperature on SOR and bottom-hole pressure. Gathering these data helped outline the specific mechanical actions performed on the reservoir and the thermal capabilities under various operational changes. The optimized conditions aimed to maximize recovery from oil reservoirs.

III. RESULTS AND DISCUSSIONS

A. Reservoir Parameters Sensitivity Analysis

This study serves as the starting point for focusing on other important factors such as optimizing specific reservoir parameters to achieve optimal results with steam flooding. This is contrary to its displacement capacity and operational efficiency, which is well-known. This work was done using a mathematical simulation approach with the aim to evaluate the effectiveness of steam flooding in heavy oil environments with respect to diverse reservoir and fluid characteristics encountered.

Analysis of steam flooding in heavy oil Environments with reservoir engineering parameters models show that critical parameters oil saturation, net to gross ratio, average permeability, average porosity and vertical to horizontal permeability ratio were major contributors to enhanced flooding outcomes.

During this optimization, numerous geological and operational conditions were tested, which included optimizing steam injection geometries within the CMG STDARS, which is an industry simulation package for reservoir energy extraction. Along with the aforementioned issue, the difficulty of bitumen's high viscosity and difficulty of heavy oil production persists through low and high steam flooding permeable formations.

Though there are variations in the reservoir's quality, the underlying physics associated with the heat transfer and fluid motion during steam flooding remains largely unchanged.

Adjustments of reservoir operating conditions along with the sensitivity analysis makes for better calibration of the reservoir model revealing how different geological features influence recovery of oil using thermal techniques. This model allows for changes in parameters, which helps to determine target systems that will increase oil mobility.

B. Optimization in Steam Injection for Heavy Oil Recovery

The availability of mobile water within reservoir fractures augments steam-based recovery techniques, including Thermally Assisted Gas/Oil Gravity Drainage (TA-GOGD) and hybrid in-situ upgrading that combines steam heating with heavy oil chemical transformations. Such integrated approaches synergistically improve calorific value and thermal recovery phases by increasing the energy balance of the system and subsurface upgrading.

Among these, steam injection is particularly prospective as a substitute for in-situ upgrading as it provides effective heating and enhances oil displacement at lower operational complexity. The idea is akin to hybrid steam-electricity co-generation systems, already utilized in the energy sector for efficiently harnessing steam and electric energy from a single source during their joint production.

It should be recognized that in algam steam injection carries out the conventional procedure of pre-heating the reservoir to 150~200°C, which is significantly lower than the temperature necessary to achieve complete in-situ upgrading, typically exceeding 320°C. Therefore, distinguishing between the advantages of thermal cracking, which lowers oil viscosity at approximately 300°C, and genuine upgrading is paramount.

The literature indicates that a grade of carbon bond breaking, one important chemical reaction in upgrading begins at temperatures slightly under 300°C. Hence, this steam-based heating may assist in the initial stages of altering viscosity and even modifying flow properties, albeit without achieving complete upgrading. Ultimately, the study underscores the importance of controlling systems for steam injection to maximize recovery and EOR in fractured or thermally responsive heavy oil reservoirs.

C. Enhanced Oil Recovery (EOR) Mechanisms in Steam Flooding

Steam flooding comes with numerous additional benefits of EOR. Many of which drastically improve oil flow and reservoir functionality, such as:

1 Hot-Water/Steam Injection – just like traditional water flooding, steam or high-grade hot water injections can assist in maintaining reservoir pressure as well as contribute energy to further displace oil towards production wells.

2 Viscosity Reduction Through Heating: The heaviness of oil rises as the temperature of the reservoir goes up. Therefore, higher temperature leads to lower viscosity, which enhances oil mobility. This phenomenon improves areal sweep efficiency, which is beneficial in accessing greater volumes of oil.

3 Improved Mobility Ratio: The smaller the ratio of oil extracted to water injected, the better. Henceforth, the thinner the oil, the higher the mobility. This means smooth and easier movement of oil within the reservoir.

4 Enhanced Vertical Sweep Efficiency: The lower the density of a liquid, the higher it rises. Thus due to its lower density, injected steam migrates into higher portions of the reservoir and in the long run, gravity ensures vertical thermal energy direction which leads to improved vertical displacement and over all layer sweep efficiency.

5 Formation Pressure Recovery: The use of hot fluids can lead to thermal expansion of fluids and rocks which can help in formation pressure restoration or sustaining it. This effect is greater with steam than with conventional heating techniques, which makes steam recovery systems greatly beneficial.

6 Changing Softer Rock Permeability As Well As Wettability: constituents, like colloids and asphaltenes, have lower likelihood to stick to the rock's surface at elevated temperatures. The hydrophilic nature of the rock also aids in lowering residual oil saturation, which increases recovery potential due to enhanced fluid displacement.

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Using these steam mechanisms makes the flooding technique efficient for obtaining heavy oil from reservoirs, where usual strategies fail because of high viscosity and low natural flow.

TABLE 1
IMPACT OF WELL DISTANCE AND STEAM TEMPERATURE ON OIL RECOVERY

Well Distance (m)	Oil Recovery Trend	Steam Temperature (°C)	Effect on Oil Viscosity	Recovery Efficiency
100	Highest recovery	150	Moderate reduction	High
150	Moderate recovery	200	Significant reduction	Higher
200	Lowest recovery	250	Very low viscosity	Highest

The information provided in Table 1 illustrates a synergistic relationship between well spacing, steam injection temperature, and recovery efficiency in heavy oil reservoirs.

At a well distance of 100 meters, the simulation showed the highest oil recovery trend overall. This operating strategy guarantees that the injected steam exerts pressure and thermal contact with the oil-bearing zones, thus contributing to the recovery and thermal efficiency of the formation. At this distance, steam at 150°C provided a moderate reduction in oil viscosity, which is advantageous for high recovery efficiency. Considered "low" in comparison to other simulations, the temperature is relatively low, but the proximity of wells maximized steam effectiveness grants surge reduction.

If growth spacing is increased to 150m, recovery became moderate. However, steam temperature was set at 200°C. The increase in temperature was proven to cause high oil viscosity, which increases the ability of the oil to freely move. As a result, this provided the scenario improvement recovery efficiency realized of steam due to the increased differential of viscosity and mobility in contrast to the scenario at 100m spacing. This approach combines equilibrium thermal energy input with effective coverage of the reservoir, making it optimal in most situations.

At the greatest distance of 200 meters, the recovery trend observed is the lowest even when the steam temperature of 250°C is used. The data suggests that even though the viscosity of the oil increases to very low values, which could result in excellent flow, the large distance between the wells (200 meters) undermines the overall effectiveness of steam sweep and thermal penetration. Hence, heat is lost before significant portions of the reservoir are reached, because effective oil displacement cannot be achieved.

To summarize, although higher temperatures increase oil mobility, oil recovery is highly dependent on the spacing of the wells. There seems to be an optimum configuration of thermal energy and layout of the wells in the steam assisted heavy oil recovery systems, which maximizes operational effectiveness.

TABLE 2
SENSITIVITY ANALYSIS OF STEAM INJECTION PARAMETERS

Well Distance	Steam Temp. (°C)	Oil Recovery	Bottom-Hole Pressure	Cumulative Oil Output	Flow Stability	Optimal Use Case
100m	150	Lowest	Moderate	Moderate	Most stable	Prolonged production phase
	200	Moderate	High	High	Less stable	Balanced recovery & pressure
	250	Highest	Highest	Highest	Least stable	Peak short-term recovery
150m	150	Low	Moderate	Low	Stable	Cost-effective, steady flow
	200	Moderate	High	Moderate	Variable	Trade-off between temp. & pressure

Well Distance	Steam Temp. (°C)	Oil Recovery	Bottom-Hole Pressure	Cumulative Oil Output	Flow Stability	Optimal Use Case
	250	High	Very high	High	Unstable	High-risk, high-reward scenarios

Table 2 gives a detailed sensitivity analysis on how changes to the steam temperatures and distances to the wells have an impact on the performance indicators in steam-assisted heavy oil extraction. The indicators include steam-oil ratio (SOR), pressure at the bottom of the borehole (BHP), cumulative oil production, flow consistency, and the most favorable operational setting for every case.

The case with a well distance of 100 meters demonstrates a very clear trend. More specifically, while steam recovery temperature remains at 150°C, the flow oil recovery gives the least values while BHP and cumalative oil output stand in moderately low values which means the abandonment point would result in the best flow stability. This enables the constant flow during the production period. Alternatively, the low-flow periods would be captured in the production phases were sharper decreases in total output are observed.

In this case, recovery rates experience moderate improvement, paired with heightened recoverable BHP pressure and output values. This makes this configuration the best to work with considering it has most relief wells pre drilled.

At this steam recovery temperature, oil recovery along with pressure and cumalative output improve drastically while BHP flow stability however, is greatly minimized. This scenario is ideal when looking for maximized rate of output for a shorter duration, although it comes at an elevated cost due to increased chance of mechanical thermal instability risks in the reservoir.

For a well spacing of 150 meters, using low temperature steam (150 degrees celsius) results in low oil recovery and output, but keeps steady flow conditions, making it suitable for lower cost operations. For a 200 degrees celsius steam, oil recovery and pressure is mid to high alongside flow volatility, indicating an energy input to performance recovery tradeoff.

At the extreme condition of 250 degrees celsius steam for 150 meter spacing, the system achieves very high bottom hole pressure, very high recovery, and unstable flow. This setup is suitable for scenarios which are high reward and high risk where maximum output is prioritized alongside the ability to take on operational challenges.

The information highlights the fact that lower temperatures and tighter well spacing will favor stability and long-term recovery, while higher temperatures and wider spacing add deviations and operational complexity. Strategic decisions have to calculate the optimal temperature regions and recovery targets to optimize reservoir performance.

TABLE 3
IMPACT OF STEAM TEMPERATURE ON OIL PRODUCTION AND PRESSURE

Steam Temp. (°C)	Effect on Cumulative Oil (SC)	Daily Oil Rate	Bottom-Hole Pressure Trend	Stable Production Achievable?
150°C	No significant change	Increased	Stable & decreased	Yes (long-term stability)
200°C	No significant change	Increased	Moderate fluctuations	Partial (less stable than 150°C)
250°C	No significant change	Increased	High/unstable	No (short-term peak output)

Table 3 analyzes the impact of different steam injection temperatures: 150°C, 200°C, and 250°C on the cumulative oil production, daily oil rate, bottom-hole pressure trends, and the potential for achieving stable long-term output.

All three temperatures have been recorded to have the same outcome impact on cumulative oil production (SC) which has been defined as ‘no significant change’. This would imply that even though higher temperatures appear to increase performance in the short term, there is no significant overall change in the total volume of oil recovered during the production cycle. Their impact is mostly in daily production rates as well as reservoir pressure movements.

The system at 150°C shows higher daily oil rates along with a gradual and stable reduction of bottom-hole pressure. These features show a favorable thermal balance that preserves the reservoir and enhances long-term production. This makes 150°C suitable for operators who want ConocoPhillips' stable volume with no risk of pressure destabilization.

At 200°C, bottom-hole pressure starts to moderately oscillate, but bottom-high oil output remains high. This middle-tier temperature increases production efficiency but also introduces periodic instability, which may be due to uneven steam delivery or slight reservoir stress. Despite not being as consistent as in the 150°C scenario, this condition is acceptable to operators who need to boost recovery while moderate control.

When evaluating the maximum oil production attainable from steam injection, it is evident that at the upper thermal limit of 250°C, the apparent daily oil production rates almost double but with very high subsurface pressure fluctuations about the bottom-hole producing zone. These results indicate a clear risk and difficulty maintaining steady and controlled production under such unstable pressure conditions. The reservoir seems to be at risk of being pushed beyond optimal operational thresholds, suggesting that such thermal regimes are not feasible for sustained production. With that said, instabilities could be exploited for short-term maximum output scenarios in situations when immediate Recovery of Oil is prioritized over long-term reservoir health.

In conclusion, all controlled parameters aid in augmenting oil recovery, but only moderate constraining temperatures of 150°C ensure a stable reliable baseline for the more continuous output needed. Sustained control and regulation of pressure while enhancing productivity from a resource, however, were not possible at higher temperatures. The extreme setting adds disabling flaws oil output burst the reservoir while compromising consistency and reliability due to the-risk of uncontrolled pressure becoming primary shadows masking true resource potential.

TABLE 4
SENSITIVITY ANALYSIS OF STEAM INJECTION IN 200M WELL MODEL (10-YEAR SIMULATION)

Parameter	150°C	200°C	250°C	Key Observations
Cumulative Oil Output	No significant change	No significant change	No significant change	Temperature variation does not significantly impact total oil recovery.
Daily Oil Production	Increased	Increased	Increased	Steam flooding boosts daily rates, but higher temperatures do not provide extra gains.
Bottom-Hole Pressure	Lowest (Stable)	Moderate Increase	Highest (Unstable)	Pressure rises sharply with temperature, risking operational challenges.
Effective Production Period	Longest (Stable flow)	Moderate	Shortest (Peak then decline)	150°C offers prolonged stability; 250°C may lead to early well/reservoir issues.
Optimal Use Case	Best for long-term production	Trade-off option	High-risk, short-term focus	Higher temperatures not justified for 200m wells due to pressure instability.

The impact of thermal input on cumulative oil recovery, daily production, reservoir pressure, and overall production efficiency in a 200 meter well spacing case was analyzed with the 150°C, 200°C and 250°C steam injection temperature simulations over a 10 year period simulation in the well shown in Table 4.

In the wider well spacing configuration, the total oil recovery is not significantly altered by increasing the steam temperature, which explains why the output remains largely unchanged for all steam injection temperatures. The assumption can be made that thermal energy contributes towards enhancing the short term mobility, but at a distance between the injectors, yield does not increase.

That said, the oil production accelerates on a daily level for every evaluated temperature level, confirming that steam injection, irrespective of the injected temperature, increases the immediate flow rates and thus, the amount of oil extracted. The compensatory effect of high temperature steam injection on daily production output is offset by its lower levels of output at lower temperature levels, highlighting diminishing returns on thermal input beyond a certain threshold.

The bottom-hole pressure trends illustrate juxtaposing scenarios: at 150 °C, pressure is low and stable, allowing for smooth and easy operation. When the temperature is taken up to 200 °C, it results in a moderate increase in pressure which introduces some variability in operations. Following this, at 250 °C, pressure transforms into high and unstable which can be suggestive of potential risks such as some degree of mechanical stress or premature reservoir failure. Indeed, these increasing pressure levels with temperature are especially troublesome, posing severe challenges to operational and safety standards, particularly with extended use in mind.

The effective temperature production period also varies. Achieving 150 °C enables the longest and most consistent production cycle. It shifts to moderate duration at 200 °C, but is characterized by rapid output spikes which rather prematurely sought the sought-after sustainability. The most potent example of this trend is high temperatures do reduce long term operational efficiency, especially in sparsely spaced wells.

To sum up, 200-meter well spacing yields best results with steam temperature set to 150 °C, providing optimal stability in pressure, output, and operational dependability. Any further increment in temperature increases risk with no significant recovery in total oil, confirming unjustifiable use of high-temperature injection to this configuration.

IV. DISCUSSIONS

The analysis foresees the impact of various steam temperatures and well spacing on the recovery performance of heavy oil using steam to yield invaluable information. As previously indicated, extraction of oil is enhanced by steam injection on account of the increased mobility of the oil resulting from lowered viscosity, hence increased production rates. However, the impact of the temperatures is mixed with well spacing and reservoir conditions.

At 100 meter well spacing, the recovery factor attained its maximum value at steam temperature of 250°C for viscosity reduction and effective areal sweep [3]. This close spacing is ensured that injected heat was in contact with the oil bearing zone was sufficient to allow displacement while contending for bottom hole pressure instability pertaining to monitoring for severe stress scenarios such as steam channeling or thermal stresses on the formation.

For 150 meter spacing, offering the most benign level of recovery with good pressure stability was 200°C steam temperature [6]. Recovery becomes well below optimum value as increased steam temperature moves towards 250°C [4]. This scenario demonstrates the highest thermal efficiency-to-stability ratio suggesting that the combination is the most operationally practical candidate for field needs where dependable output with minimal risk is required [25].

Applying high-temperature injection at 250°C did improve flow rates for 200-meter spacing but the thermal efficiency and production stability fell sharply. Increased spacing caused greater heat loss, reducing the thermal energy's useful influence range while causing bottom-hole pressures to become unstable. This resulted in loss of wells' productive lifespan and potential premature decline, highlighting the counterproductive effects of increased heat in thermally widespread well arrangements [1].

Regardless of scenario, the increase in temperature didn't greatly impact the total cumulative oil output. This supports the finding that elevated temperatures do improve short-term production rates but does not greatly influence oil recovery levels in the long term. In comparation, lower steam temperatures 150°C resulted in reliable prolonged production highlighting their appropriateness for long-term utilization, especially for thermally sensitive reservoirs.

As part of the simulation, daily oil production levels, bottom-hole pressure movements, and production stability were monitored. There was an increase in daily production with increase in temperature under all conditions, however, only the 150°C condition was able to maintain stable flow during the entire 10-year forecast period, particularly in tighter wellbore configurations [11].

The sensitivity analysis exposed additional impacts of thermal expansion and rock wettability modifications at higher temperatures; these factors tend to enhance initial displacement efficiency but may cause early pressure instability if not properly controlled. Furthermore, the steam-to-oil ratio (SOR) was observed to increase slightly with temperature, meaning more energy is required for each barrel of oil obtained, which can be detrimental to energy return on investment (EROI) during prolonged operations.

In conclusion, the optimization of steam temperature and well spacing individually has a risk of operational failure, while in unison along with thermal efficiency and production stability is necessary. Though outcome confirms the geothermal-assisted steam injection's geothermal system use strategy, it modifies the power needed input suggesting, along with well spacing needed handling design for long-term recovery.

V. CONCLUSION

The current research offers a thorough computational evaluation of the application of geothermal enhanced steam injection in the complete recovery of heavy oil from the Bohai NB35-2S field. The CMG-STARS simulations were used to determine the effects of varying steam temperatures (150°C, 200°C, 250°C) and well spacings (100m, 150m, 200m) on oil viscosity, reservoir pressure, production stability, and cumulative recovery over a ten year period.

Higher steam temperatures were shown to improve daily oil extraction by greatly reducing oil viscosity; however, there was no substantial improvement in cumulative oil production during the ten year period. In contrast, a lower temperature of 150˚C was noted to be more favourable in terms of maintaining bottom-hole pressures and supporting prolonged production periods, especially at tighter well spacings. From the analysis it was clear that moderate thermal input and compact well spacing give better results than other high and low extremes because of improved balance between thermal efficiency, oil displacement, and reservoir stability.

With broader well spacings, thermal losses and pressure instability diminish the advantages of high-temperature injection, restricting its effectiveness for prolonged recovery quantifications. In addition, the investigation reveals that higher steam temperatures increase the steam-to-oil ratio (SOR), thereby undermining energy efficiency and increasing the burden on sustainability for long-term operations. Further sensitivity analyses reveal that alterations in rock wettability and permeability at higher temperatures can accelerate recovery but pose significant operational risks if not controlled properly.

At last, the combination of steam injection with geothermal energy offers an effective technique for sustainable enhanced oil recovery. But, the combination of well positioning with injection temperature needs to be fine-tuned. The research brings forth important considerations for the design of thermal recovery processes with respect to energy consumption, output (productivity), and preservation (control) of reservoir in heavy oil fields.

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