processes

Article

Study on Thermal Chamber Expansion of VH-SAGD Process Using CO_2-Inducing Effect for Heavy Oil Reservoirs

Haojun Xie *, **Shiming Zhang**, **Guanghuan Wu** and **Wei Li**

Exploration and Development Research Institute of Shengli Oilfield, Sinopec, Dongying 257000, China; zhangshm855.slyt@sinopec.com (S.Z.); wuguanghuan.slyt@sinopec.com (G.W.); lwnd@163.com (W.L.)
* Correspondence: xiehaojun.slyt@sinopec.com or paodanpaodan@126.com; Tel.: +86-(0546)-8715430

Abstract: In heavy oil thermal recovery processes, higher pressure usually leads to low dryness and expansion difficulty for the injected steam in thermal recovery processes, which will result in lower oil recovery and more carbon emissions. This paper proposed a new CO_2-inducing method to accelerate the steam chamber expansion, based on a core flooding experiment and numerical simulation. First, the CO_2 showed significant viscosity reduction at high pressure in the PVT test. In the core flooding experiment, the CO_2 provided strong flow conductivity in porous media for the thermal flooding, as the CO_2 pre-injection restrained the steam condensation. Using the CO_2-inducing method, CO_2 pre-injection before steam built a fast flow channel in a relatively higher permeability layer and reduced the thermal injection pressure by about 1.0~2.4 MPa. As a result, the steam overlap around the injection wells became slower and the gravity drainage process was able to heat and displace the heavy oil above the channel. Furthermore, the CO_2 gas trapped at the top reduced heat loss by about 12.4%. The field numerical simulation showed that this new method improved thermal recovery by 7.5% and reduced CO_2 emissions by about 18 million kg/unit for the whole process. This method changes the conventional thermal expansion direction by CO_2 inducing effect and fundamentally reduces heat loss, which provides significant advantages in low-carbon EOR.

Keywords: heavy oil; CO_2 inducing; thermal chamber; gravity drainage

check for updates

Citation: Xie, H.; Zhang, S.; Wu, G.; Li, W. Study on Thermal Chamber Expansion of VH-SAGD Process Using CO_2-Inducing Effect for Heavy Oil Reservoirs. *Processes* **2024**, *12*, 2260. https://doi.org/10.3390/pr12102260

Academic Editor: Fabrizio Scala

Received: 29 September 2024
Revised: 14 October 2024
Accepted: 14 October 2024
Published: 16 October 2024

1. Introduction

1.1. Thermal Chamber Expansion in Heavy-Oil Reservoirs

Global heavy oil resources have reached 1.4 trillion tons, with an annual production of 653 million tons. Proven heavy oil reserves are 815 billion tons, accounting for about 70% of the world's remaining proven oil reserves, which are important for global energy supply. Due to the high oil viscosity and thermal sensitivity, thermal oil recovery by steam, such as via steam huff and puff, steam flooding, and steam-assisted gravity drainage (SAGD), is the most effective way to improve oil production and recovery [1,2].

The SAGD method was first promoted by Butler in the 1980s and industrialized in Canada from the 1990s [3,4] in areas such as Christina Lake and the Mackay River oilfields. As shown in Figure 1, SAGD uses two horizontal wells drilled in parallel in a lower position of the reservoir; the appropriate distance between the two wells is about 5 m [5]. Oil will be produced from the well located in the lower area of the oilfield, and the parallel well above that point is used for steam injection, through which a steam chamber is generated [6,7]. Using this combination, heat diffuses upwards from the upper well to the reservoir. As the reservoir temperature is increased, heat is transferred to augment the oil temperature and consequently decrease its viscosity. As a result, oil will flow down to the production well by gravity. As the steam chamber expands in the reservoir, the oil above the dual horizontal wells will be produced and oil recovery will reach up to 60~70% at ideal conditions.

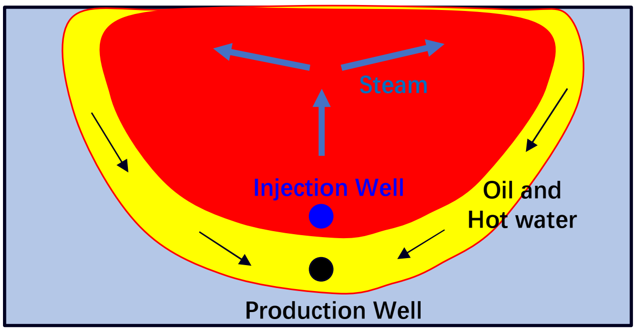


Figure 1. Dual horizontal well SAGD.

For heavy oil reservoirs buried in the range of 200 to 600 m, the oil normally exists as oil sand or bitumen such as that in the Long Lake oilfield in Canada [8]. The oil viscosity is over 10,000 mPa·s and is usually developed by SAGD.

If the heavy oil reservoirs are buried over 600 m, the steam huff and puff method is first conducted using vertical wells. Assisted with elastic energy, the steam mass injected for unit oil production (steam–oil ratio) in this period is about 0.5~1 and the reservoir pressure decreases to 2~5 MPa. However, the heating radius cannot exceed 70 m due to limited steam injection and heat loss in the formation. As the reservoir pressure decreases, the reservoir pressure becomes much lower and the steam dryness is increased to 0.7~0.8. Then, steam flooding or SAGD will take over to heat the remaining oil far from the wells and oil recovery will be improved by 20~40% [9–11]. In order to take full advantage of the original vertical wells, the VH-SAGD method (vertical and horizontal well combinational SAGD) was promoted to reduce the investment cost [12,13]. With the rapid increase in the heating area, heat loss is much greater than that in steam huff and puff; the cost is much higher for the amount of steam per unit of oil production. The steam–oil ratio in steam flooding thus decreases to 0.1–0.3 for SAGD/VH-SAGD [14–16]. Considering the formation oil viscosity, steam flooding is commonly used for oil viscosities below 10,000 cp and SAGD/VH-SAGD for oil viscosities over 10,000 cp. This has proved to be a very efficient method in many heavy oil reservoirs buried below 900 m in Canada and China [17,18].

When heavy oil reservoirs are buried by over 1000 m, the reservoir pressure after steam huff and puff maintains a high level, of 8~9 MPa, due to the high initial pressure and edge water. This leads to a high injection pressure, low dryness, and expansion difficulties for the injected steam; therefore, steam flooding, SAGD, and VH-SAGD generally cannot be adopted in deep heavy oil reservoirs.

1.2. Carbon Emission in Thermal Recovery

For reservoirs with lower thickness and higher viscosity, steam overlap can lead to higher heat loss and a lower oil–steam ratio (OSR). Steam generators are commonly used for steam generation and use crude oil or natural gas as fuel. Compared to conventional water-flooding development reservoirs, the generators emit significant amounts of carbon dioxide and are more costly. According to statistical results, thermal production, in regions such as North America and China, is greater than 130 kg/bbl of carbon [19–21], which is more than twice the level of light- and medium-crude oil production. Furthermore, SAGD, VH-SAGD and steam flooding are 40 kg/bbl higher [22,23]. Therefore, with the development of heavy oil thermal recovery in the middle and late stages, thermal recovery development costs and carbon emissions will continue to rise.

In the last 15 years, some heavy oilfields have tried to use the non-condensate gas-assisted thermal recovery method to improve oil production rates; this has proved to be an efficient way to enhance the steam–oil ratio and reduce heat loss [24–26]. Carbon dioxide and nitrogen are frequently used as a non-condensate gas. CO_2 showed significant reduction effect of oil viscosity and thermal injection at the beginning of the steam huff and puff method [27–29], for example, in Z411 extra-heavy oilfield. While nitrogen was injected to reduce heat loss to the cap rock during the middle periods of VH-SAGD or SAGD [30–32], for example, in the Du84 extra-heavy oilfield, the steam–oil ratio was increased by 0.4~0.6. Nevertheless, the high flow capacity of non-condensate gas led to thermal and fluid channeling, for example, in the NB35-2 heavy oil field [33,34]. However, non-condensate gas has never been used to induce steam flow and thermal expansion in these studies and applications.

1.3. Method Innovation Research Directiom

The economy and emission problems have led to a 17% decrease in international heavy oil trade since 2016. At the same time, international oil demand and production have continued to rise over the past three years. The continuous decline in heavy oil production has further increased pressure on international energy supply and demand. Therefore, reducing carbon emissions and the cost of heavy oil thermal flooding to increase heavy oil production and recovery will have an important impact on improving the international crude oil supply and demand balance.

Sedimentary facies of most heavy oil reservoirs are fluvial or have a fluvial delta face of continental deposits, which have a positive rhythm with a high-permeability layer in the middle of the longitudinal section [22,34]. However, steam overlap is a main function during the SAGD/VH-SAGD process. If a rapid thermal flow channel can first be built in the higher-permeability layer between the injection and production wells, it could slow down the steam overlap effect and heat loss to the cap rock.

Therefore, this study evaluated the viscosity reduction and flow conductivity of CO_2 in multi-thermal flow with a core-scale experiment that showed a significant effect on thermal injection pressure and flow resistance. Thus, a CO_2-inducing VH-SAGD method was proposed to build a horizontal rapid flow channel that can delay the steam overlap around the injection well. The steam-assisted gravity drainage works along the whole area between the injection and production wells, resulting in reduced heat loss and carbon emissions. This method offers an economic new method for deep heavy oil thermal recovery.

2. Experimental

2.1. Fluid Property Test

Considering the high pressure of the reservoir, high temperature during the thermal recovery process, the steam phase change, and carbon dioxide dissolution in oil, the flow resistance of different thermal fluids was first evaluated by a core flooding experiment.

The S2 heavy oil reservoir in Shengli Oilfield of Sinope China (Dongying, China), which is buried under 1200 m and has strong edge water, was selected for the research case. Using a stock tank oil sample taken from the production well, the carbon dioxide dissolution experiment was conducted at different pressures and temperatures with PVT instruments (manufactured by Huabao Ltd., Yangzhou, China). Then, the bubble-point pressure of the CO_2 and the oil viscosity were measured, as shown in Figures 2 and 3. For ordinary heavy oil reservoirs with pressures of 2~5 MPa, the CO_2 solution (GOR) is about 10~37 sm^3/sm^3 at 60 °C, and the oil viscosity can be reduced by 59~85%. With the reservoir pressure increased to 8~9 MPa, the GOR can be improved to 55~60 sm^3/sm^3 and the viscosity reduction would reach 70~95%.

On the other hand, the temperature has an obviously negative effect on the GOR due to the heating precipitation. If the steam heating zone temperature increases to 150 °C at 2~5 MPa, most CO_2 would diffuse from the oil phase to the gas phase and the GOR would decrease to 1~5 sm^3/sm^3. Then, the viscosity reduction and carbon storage would be significantly reduced. For a deep heavy oil reservoir with a higher pressure of 8~9 MPa, the CO_2 GOR would maintain at 25~29 sm^3/sm^3 at 150 °C. The CO_2 still has a considerable viscosity reduction and carbon storage effect in these conditions; therefore, CO_2-assisted thermal recovery development is more suitable for deep heavy oil.

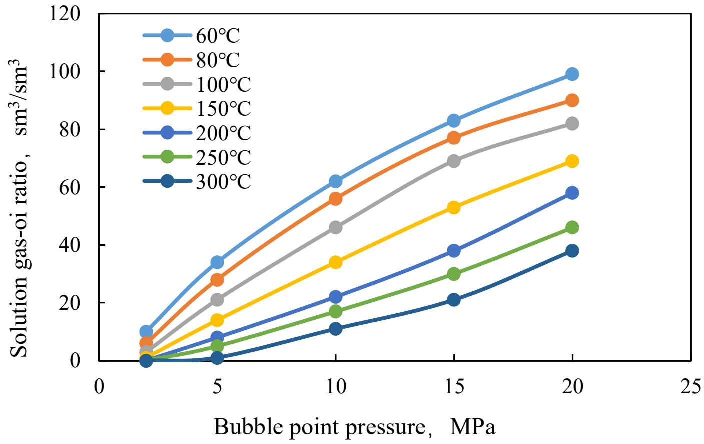


Figure 2. Bubble-point pressure of CO_2 and oil at different temperatures.

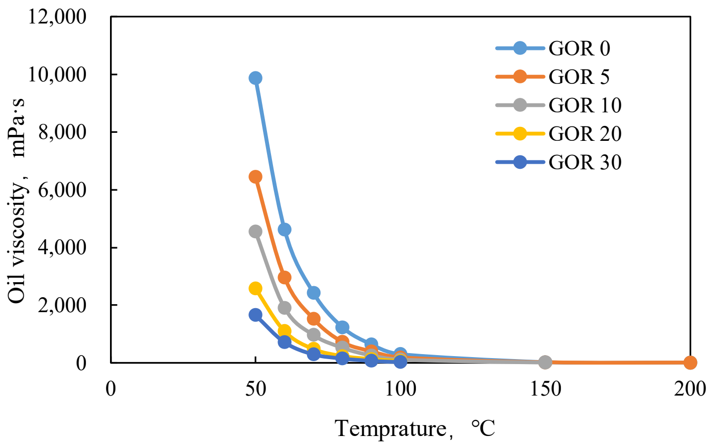


Figure 3. Oil viscosity with solution CO_2 at different temperatures.

2.2. Thermal Flooding Experiment

The fluid distribution and phase have a great influence on flow resistance, while the gas phase and flooded channel usually leads to steam channeling. In order to evaluate the flow capacity of different fluids at different water saturation heterogeneities after steam huff and puff, the flow resistance for different thermal fluids was tested by a core flooding experiment.

The multi-thermal fluid flow experimental diagram is shown in Figure 4. First, the sand-pack with different water saturations (Sw) was manufactured. The porosity of the sand-pack was about 35% and the bulk density was about 1.7 g/cm^3; therefore, the pore volume per unit mass of sand could be calculated. Based on the water saturation and pore volume, the volume of water and oil was calculated. According to the design quantity, the dry sands and water were mixed and fully stirred. Then, the heavy oil was added into the wet sand and fully stirred again. Finally, the mixture was filled into the sand-pack tube and compressed so that the sand-pack with different water saturations (Sw) could be manufactured.

An oven was used to maintain the reservoir temperature (50 °C) and pressure (9 MPa) of the sand-pack. Second, the liquid CO_2 and purified water were injected into the steam generator over 9 MPa. The flow rate of CO_2 and water was controlled precisely at 0.00~5.00 mL/min for different thermal fluid flow experiments by an ISCO A260D (manufactured by Teledyne, Lincoln NE, USA) micro pump. Then, the CO_2 and water were heated to the temperature of the multi-thermal fluid of the gas phase with 100% dryness. Third, as the multi-thermal fluid flowed through the sand-pack, the flow pressure gradient was measured with a differential pressure sensor between the inlet and outlet.

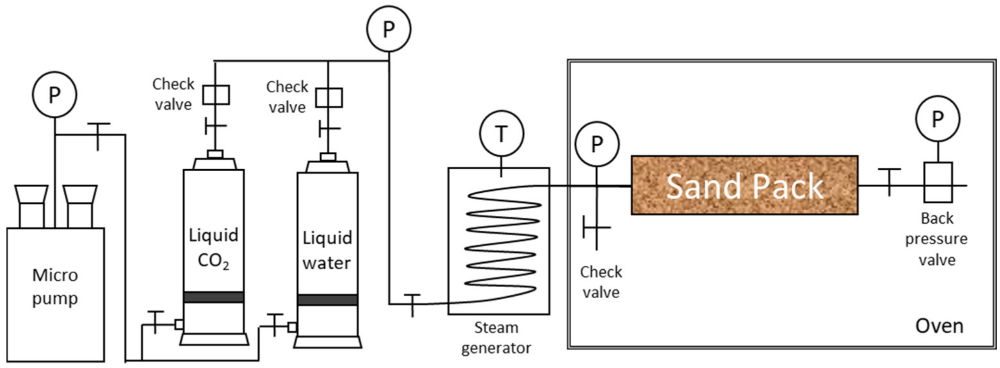


Figure 4. Multi-thermal fluid flow experimental diagram.

2.3. CO_2-Inducing Effect

Using the fluid flow experiment at the core scale, the dynamic changes of flow resistance for steam are shown in Figure 5. Considering that the reservoir temperature will recover to the initial reservoir temperature at the end of the steam huff and puff application, the sand-pack was placed at the initial reservoir temperature at high pressure. Thus, the oil viscosity was about 9871 cp, which meant that it was difficult for the oil to flow through a porous medium. At the beginning of the thermal fluid injection at connate water saturation (Sw = 0.25), the heat had not been injected into the core and it was difficult for the oil to flow through the sand-pack. The steam at the inlet transformed to the liquid phase (hot water) and the pressure gradient increased slowly. Between 40~80 min, the pressure gradient began to grow swiftly and reached a maximum value of 5.5 MPa/m. Then, the hot water flowed into the sand-pack at high pressure. After the peak value was reached, the injected steam or condensate water heated the oil in the porous media and the pressure gradient dramatically declined to 0.2 MPa/m due to the reduction in oil viscosity.

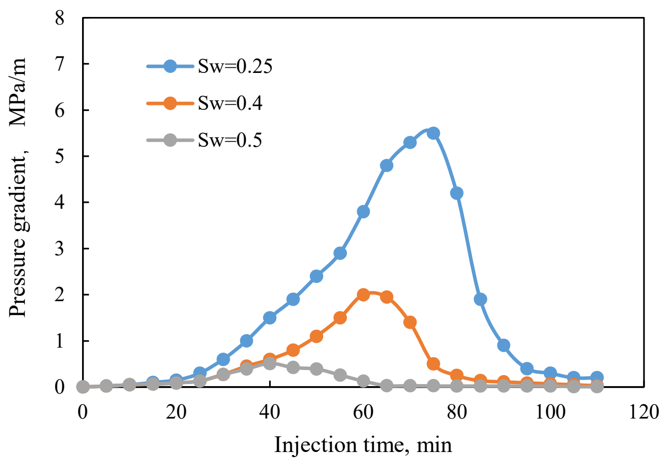


Figure 5. Pressure gradient of steam flow in sand-pack at different water saturations.

If the water saturation increases to 0.4~0.5, the water phase in the porous media of the sand-pack would have an initial flow capacity at reservoir temperature. Then, the multi-thermal fluid could flow through those pores at a lower pressure. Therefore, the maximum pressure gradient would decrease to 0.51~1.95 MPa/m, and the stable flow pressure gradient after the peak value would be 0.01~0.03 MPa/m. Therefore, formation produced by steam huff and puff would have higher water saturation and flow ability for the steam.

Furthermore, the flow resistance for different thermal fluids was evaluated and is shown in Figure 6. For single CO_2 gas injection, the oil dissolved at reservoir temperature and reduced the oil viscosity by about 65% at the beginning. Then, the maximum pressure gradient would be1.7 MPa/m lower than steam in connate water saturation conditions (Sw = 0.25). Since the CO_2 gas phase has greater flow mobility than liquid and the increase in water saturation (Sw = 0.4) would offer initial flow capacity, the CO_2 max pressure gradient would decrease to 0.45 MPa/m, which is 70% lower than single steam.

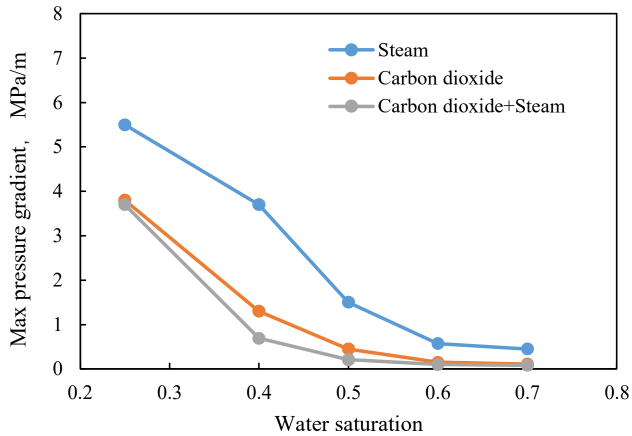


Figure 6. Maximum pressure gradient of multi-thermal fluid flow at different water saturations.

If we injected steam after the CO_2 slug, the steam would flow through the CO_2-induced channel and heat the oil in the sand-pack. The maximum pressure gradient could be further reduced to 0.21 MPa/m. Therefore, the CO_2 pre-injection can induce a rapid flow channel in the porous media for the steam, which can reduce the steam injection pressure and improve the dryness significantly.

3. Numerical Simulation

3.1. Reservior Characters

The sand layer group of S2 consists of five layers with edge water; the average thickness and physical properties for single layers are shown in Table 1. The sand layer group is a compound rhythm with higher permeability in the middle layer 3#, and there is no obvious and continuous interlayer. After years of steam huff and puff, the average oil saturation has been reduced from 0.68 to 0.48~0.58; however, the average pressure decreased slowly from 11 Mpa to 9 MPa because of edge water incursion. Due to the steam overlap, the average oil saturation of top layer 1# is 0.49, especially around the production well. Under the combined influence of higher permeability and edge water incursion, the average oil saturation of middle layer 3# is 0.48, according to the well-logging interpretation results, which was the lowest in the sand layer group. Considering the water saturation and permeability, the 3# layers could form a rapid flow channel for multi-thermal fluid flow with CO_2 and steam.

Table 1. Average thickness and physical properties for single layers of S2.

Layer	1#	2#	3#	4#	5#
Average Thickness, m	13	12	9	6	7
Average Porosity	0.337	0.337	0.355	0.342	0.334
Average permeability, mD	3453	3403	4560	3604	2416
Average Oil Saturation	0.49	0.52	0.48	0.58	0.57

3.2. CO_2-Induced VH-SAGD Method

At a high reservoir pressure, conventional SAGD using a double horizontal well cannot be adopted since the steam would transform to hot water and the steam chamber expansion rate is too low. In the meantime, the original vertical well for steam huff and puff could not be used for the SAGD process and drilling new horizontal wells would significantly increase the investment cost. Using the original vertical injection well and a new horizontal production well, VH-SAGD could reduce the investment cost and improve the steam flooding effect at high pressure.

However, conventional VH-SAGD at high reservoir pressures could result in a higher injection pressure and a lower steam injection rate, which would aggravate the steam overlap around the injection well and cause huge heat (over 40%) losses to the cap rock. As shown in Figure 7, gas flow to the top is the main cause of steam overlap and heat loss. The vertical flow rate must be controlled and the horizontal flow rate must be improved to reduce steam overlap. As CO_2 can reduce oil viscosity and build a rapid flow channel, it can be injected before the steam to reduce the thermal injection pressure. As shown in Figure 8, the injected steam after CO_2 flows along the rapid flow channel and the heat is then transported from the injection well to the production well. The steam channel is generated in the middle layer 3# of the formation; afterwards, the steam heats the oil layer over the steam channel rather than the cap rock to reduce heat loss.

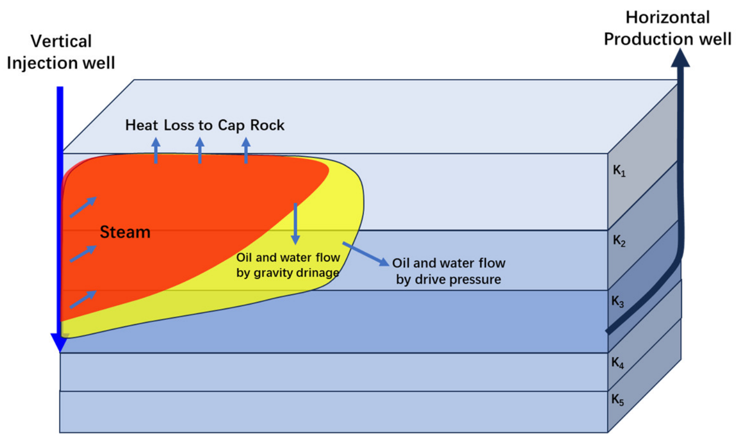


Figure 7. Conventional VH-SAGD steam chamber and heat loss to the cap rock.

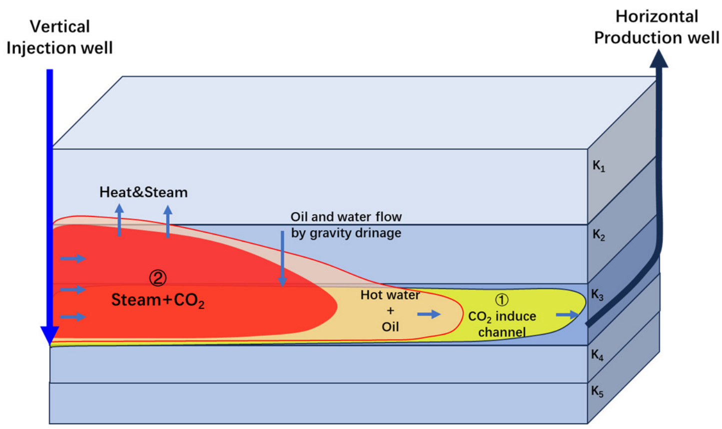


Figure 8. Vertical and horizontal well combination VH-SAGD using the CO_2-inducing method.

3.3. CO_2-Induced VH-SAGD Model

In order to evaluate the VH-SAGD steam chamber expansion and heat utilization ratio, a typical well group model was built for the S2 reservoir using CMG-STARS software (version 2020.10). The horizontal and vertical well groups are shown in Figure 9 and the injection and production parameters are shown in Tables 1 and 2. To make full use of the original vertical well, the new horizontal production wells were placed between the vertical well lines; therefore, the producer–injector spacing was set to 40 m. Considering the CO_2-inducing effect, the horizontal well segment and vertical well perforated interval were placed in middle layer 3#. For conventional VH-SAGD, the steam was injected in the vertical well to build the heat connection and steam chamber. For CO_2-induced VH-SAGD, the CO_2 was pre-injected at 5000 sm^3/day for 5 days to build the fast flow channel. Then, the steam was injected with a CO_2 (500 sm^3/day) slug. The multi-thermal fluid injection maximum pressure was limited to 14 MPa to guarantee steam dryness; the production minimum pressure was limited to 8 MPa to avoid edge water flooding.

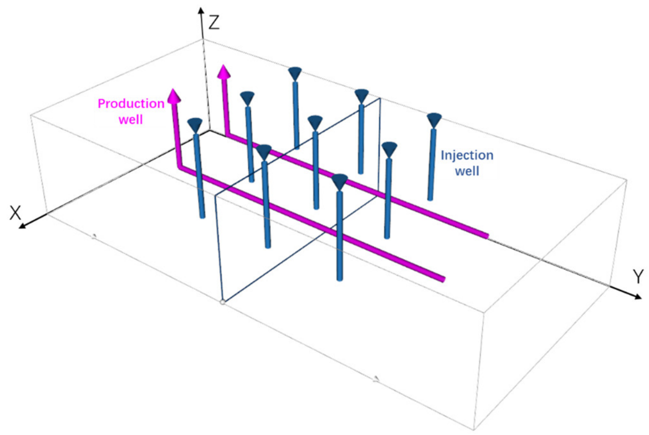


Figure 9. Three-dimensional structure of VH-SAGD injection–production well group.

Table 2. Injection and production parameters design for VH-SAGD.

Parameter	Value
Oil in place	135×10^6 m^3
Initial reservoir average pressure	9 MPa
Horizontal well length	300 m
Injection–production well ratio	9:2
Single-well liquid production rate	300 m^3/day
Producer–injector spacing	40 m
Single-well steam injection rate (water equivalent)	≤350 m^3/day
Single-well CO_2 injection rate	500~5000 sm^3/day
Bottom-hole pressure of production well (water equivalent)	≥9 MPa
Bottom-hole pressure of injection well (water equivalent)	≤14 MPa

4. Results and Discussion

4.1. Steam Chamber Expansion

Due to the high permeability and water saturation of 3#, the CO_2 has a strong flow capacity, according to the abovementioned experiment. As shown in Figure 10, the pre-injected CO_2 flows to the production horizontal well rapidly through middle layer 3#, and the CO_2 gas saturation in layer 3# can reach 0.01~0.03 in 5 days.

In order to restrain the edge water incursion from the left side, the minimum horizontal bottom-hole pressure (BHP) was controlled at 9 MPa. In Figure 10, the CO_2 gas was injected at a relatively high pressure (BHP 13~14 MPa in Figure 11) and flow rate to build the rapid flow channel in about 5 days. The total volume of CO_2 injected was about 2500 m^3 at reservoir conditions. This had no influence on the edge water; therefore, the CO_2 gas could flow uniformly from the vertical well to the horizontal wells on both sides.

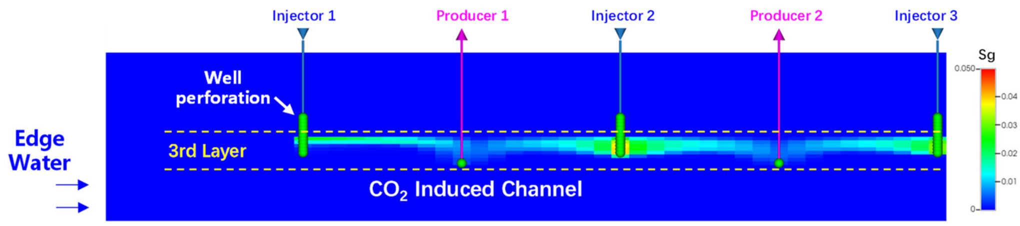


Figure 10. Gas saturation of CO_2 pre-injection after 4 days.

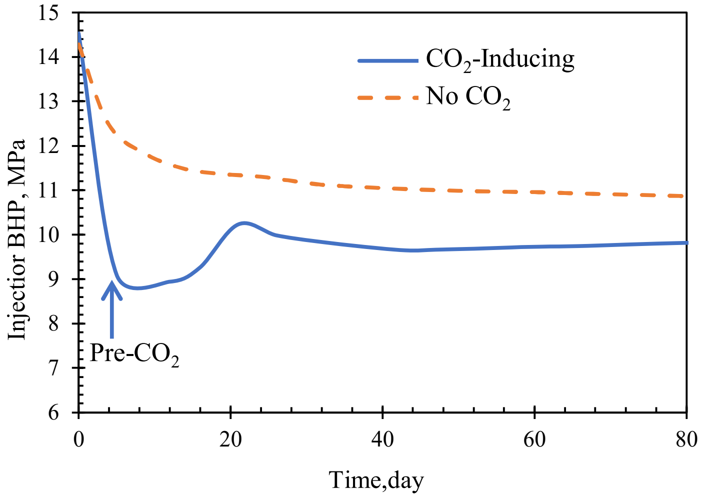
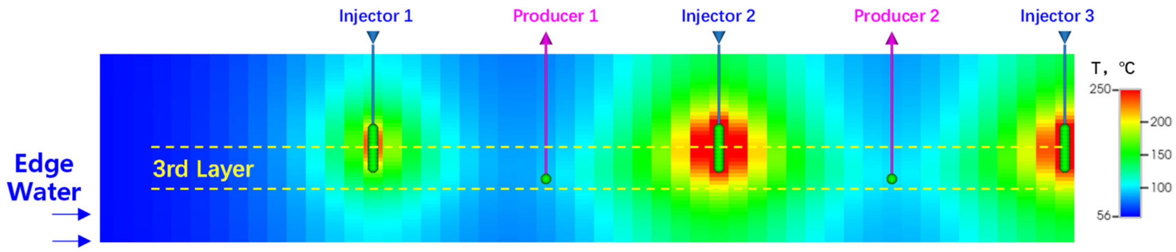


Figure 11. Well bottom-hole pressure of injectors for different methods.

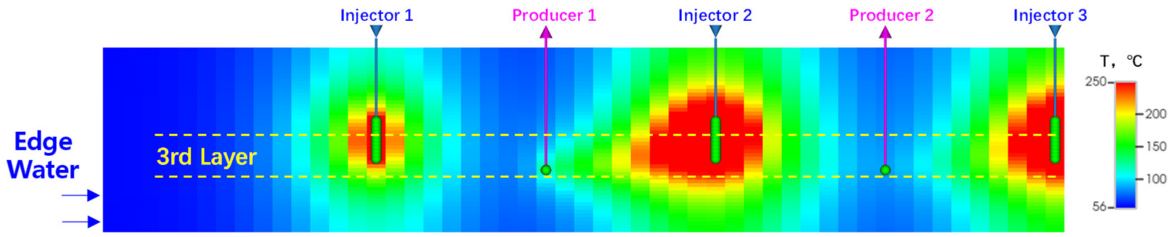
As a result of the thermal fluid flow capacity difference, the bottom-hole pressure of the injectors had obvious differences. For conventional VH-SAGD, the steam injection pressure would slowly decrease from 14 MPa to11.3 MPa (shown in Figure 11), since the initial water saturation was higher than the connate water saturation. However, the CO_2 injection pressure directly decreased to 8.9 MPa in 5 days, which was 2.4 MPa lower than that of steam. Then, the multi-thermal fluid injection pressure of the steam and CO_2 slowly increased to 10.3 MPa because condensate hot water has a higher flow resistance than the gas phase. It can be seen that the CO_2 reduces the injection pressure by about 1.0~2.4 MPa in the primary stage, which enhances the steam dryness and injected heat quantity. With the continuous injection of thermal fluid, the temperature of the thermal swept area increases rapidly and the flow resistance in the reservoir decreases. Therefore, the injection pressure values of the different VH-SAGD methods would become closer after 60~80 days.

Reservoir pressure is the key factor for steam chamber expansion; therefore, steam flooding, SAGD and VH-SAGD are normally conducted at pressures below 5 MPa. If conventional VH-SAGD was carried out at a higher pressure over 9 MPa, the steam chamber volume would be compressed, as shown in Figure 12a. The steam overlap at the injection well results in strong heat transport in a vertical direction, and significant amounts of heat would be lost from the top layer 1# to the cap rock. The high-temperature area (≥250 °C) was only 10 m long when the hot water reached the horizontal production well after 240 days, as shown in the red cell in Figure 12a. The hot water flowed in most areas; however, the heat release by liquefaction cannot heat most areas in the formation.

In contrast, the CO_2-inducing effect enhances the horizontal flow velocity and reduces the steam partial pressure; thus, the steam can travel a greater distance. It can be seen from Figure 12b that the high-temperature area (≥250 °C) can reach up to 24 m after 180 days, which is 12 m further and 60 days faster than conventional VH-SAGD. The steam chamber preferentially expands in the horizontal direction in middle layer 3#; then, the steam will heat layers 1# and 2# l rather than the cap rock. With the continues injection of thermal fluid, the condensed hot water and heated oil in layer 1# and 2# will flow down to layer 3#, which is then produced by the horizontal production well.



(**a**) Conventional VH-SAGD at 240 days



(**b**) CO_2-induced VH-SAGD at 180 days

Figure 12. Temperature distribution on the vertical section for different methods.

However, the thermal chamber tends to expand to the left side in both conditions. In the continuous steam injection stage shown in Figure 12, the injection pressure decreased to 9.5~11 MPa to ensure the dryness of the steam (as shown in Figure 11). The minimum horizontal bottom-hole pressure (BHP) was still controlled at 9 MPa to restrain the edge water incursion from the left side. Thus, the pressure difference between the injection and production well decreased from 4~5 MPa to 0.5~1.5 MPa, and the steam and thermal chamber expanded in both vertical and horizontal directions. The pressure of the thermal chamber was still a little higher than the edge water (9 MPa) on the left and the right side was a closed boundary; therefore, the middle thermal chamber (around Injection Well2) expanded and was slightly offset to the right after several months.

4.2. Thermal Recovery Results

Based on the well group simulation of VH-SAGD, the thermal utilization factor, oil production rate, and oil steam ratio were analyzed by year, as shown in Figures 13 and 14. Due to the rapid expansion speed in the horizontal direction, the single-well oil production rate in the first year was 9 m^3/d (about 23.7%) higher than that of conventional VH-SAGD. This advantage would last about five years, and then decrease to the same value with conventional VH-SAGD after 7 years, when the steam chamber occupies the most areas in the well group. Under the effect of steam overlap, the steam denudation process would be slow in conventional VH-SAGD, and the oil production rate and decline rate would be relatively lower.

After ten years of VH-SAGD, the oil recovery of CO_2 diversion VH-SAGD would increase to 57.2%, which is 7.5% higher than that of conventional VH-SAGD. Heat loss to the cap rock would be reduced by 12.4%. More heat would be used for heating oil in the formation for CO_2-diversion VH-SAGD; the oil–steam ratio would be 0.036~0.043 higher. Therefore, this method would save about 40 kg steam for one ton of heavy oil production, which means that 2.6 sm^3 of natural gas would be saved, with CO_2 emissions reductions of 5.4 kg. Considering the whole process of VH-SAGD in S2, CO_2 emissions reductions of about 0.8 million kg/well and 16 million kg/unit over ten years would be achieved by reducing fuel consumption. At the same time, about 27% of CO_2 gas would be stored in the reservoir according to the numerical simulation, which means that the storage amount is about 1.13 million Nm^3(about 2.25 million kg) for this unit. Therefore, the CO_2 emissions reductions would reach about 18 million kg/unit with the VH-SAGD process.

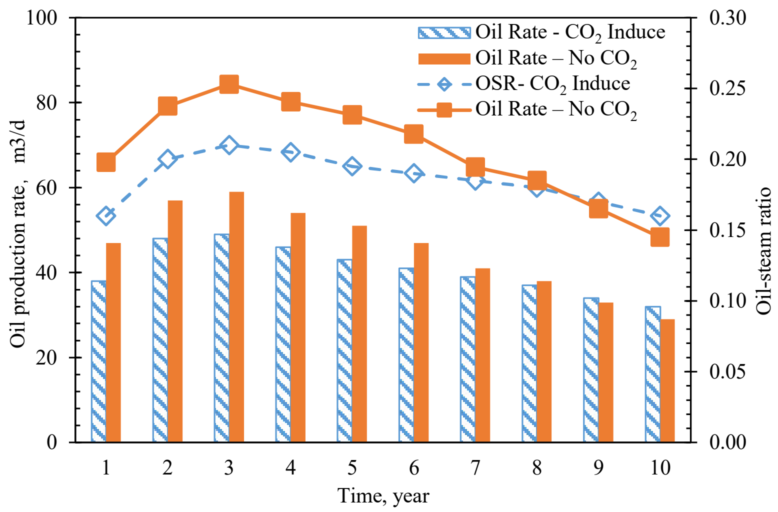


Figure 13. Average oil rate and OSR of production well for different VH-SAGD methods.

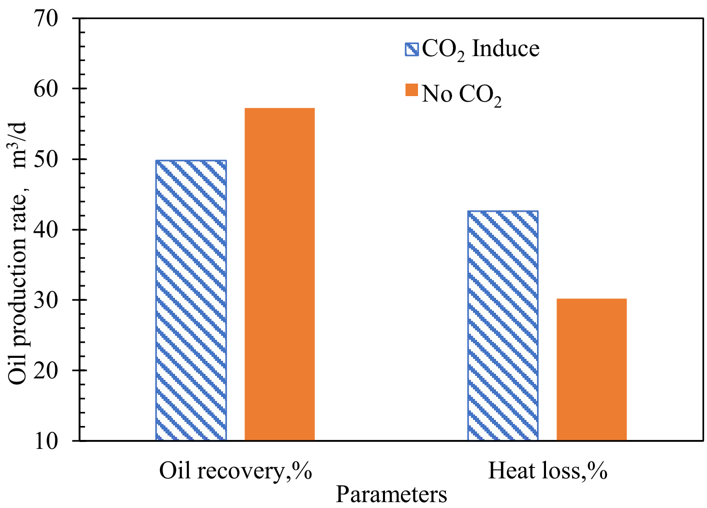


Figure 14. Oil recovery and heat loss for different VH-SAGD methods.

5. Conclusions

In this paper, a CO_2-inducing VH-SAGD method was promoted and represented for the first time. By transforming the disadvantage of CO_2 channeling to the advantage of the inducing effect, the conventional steam expansion direction was changed. Thus, it restrained the steam overlap, accelerated the thermal chamber expansion speed and enhanced the oil recovery. Moreover, it reduced the steam consumption and achieved partial CO_2 storage, which offers great advantages in low-carbon EOR. The main findings are summed up as follows:

- The CO_2 dissolution and viscosity reduction are relatively higher in deep heavy oil reservoirs. Combined with high flow capacity, the CO_2 pre-injection could reduce the steam injection pressure by about 1.0~2.4 MPa, which can help to improve steam dryness and heat injection;
- The CO_2 pre-injection is able to build a horizontal rapid flow channel in a relatively higher permeability layer, which can accelerate thermal expansion between injection and production wells. This can also slow down the steam overlap around the injection well;

- For deep buried heavy oil reservoirs, using the CO_2-induced VH-SAGD method could increase oil recovery by 7.5% and the oil–steam ratio by 0.036~0.043 over conventional VH-SAGD;
- Considering steam boiler fuel savings and CO_2 storage, the new method could reduce CO_2 emissions by 18 million kg/unit in ten years. It offers a more economical and environmentally friendly method for heavy thermal recovery.

Author Contributions: Conceptualization, H.X. and G.W.; methodology, S.Z.; software, H.X.; validation, W.L.; formal analysis, H.X.; investigation, H.X.; data curation, H.X.; writing—original draft preparation, H.X.; writing—review and editing, H.X.; supervision, G.W.; project administration, G.W. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by the National Natural Science Foundation of China (grant no. U20B6003) and Sinopec Research Project (grant no. P23055).

Data Availability Statement: The original contributions presented in the study are included in the article; further inquiries can be directed to the corresponding author.

Conflicts of Interest: Authors Haojun Xie, Shiming Zhang, Guanghuan Wu and Wei Li were employed by the Sinopec. The Sinopec had no role in the design of the study; in the collection, analyses, or interpretation of data; in the writing of the manuscript, or in the decision to publish the results.

References

1. Butler, R.M. *Thermal Recovery of Oil and Bitumen*; Prentice Hall: Englewood Cliffs, NJ, USA, 1991.
2. Zhao, D.W.; Wang, J.; Gates, I.D. Thermal Recovery Strategies for Thin Heavy Oil Reservoirs. *Fuel* **2014**, *117*, 431–441. [CrossRef]
3. Butler, R.M. Rise of Interfering Steam Chambers. *J. Can. Pet. Tech.* **1987**, *26*, PETSOC-87-03-07. [CrossRef]
4. Butler, R.M. SAGD Comes of Age. *J. Can. Pet. Technol.* **1998**, *37*, 9–12. [CrossRef]
5. Butler, R.M. Some Recent Developments in SAGD. *J. Can. Pet. Technol.* **2001**, *40*, 215–218. [CrossRef]
6. Liu, H.; Cheng, L.; Huang, S.; Jia, P.; Chen, M. Evolution Characteristics of SAGD Steam Chamber and Its Impacts on Heavy Oil Production and Heat Consumption. *Int. J. Heat Mass Transf.* **2018**, *1*, 579–596. [CrossRef]
7. Ji, D.; Xu, J.; Lyu, X.; Li, Z.; Zhan, J. Numerical Modeling of The Steam Chamber Ramp-Up Phase in Steam-Assisted Gravity Drainage. *Energies* **2022**, *15*, 2933. [CrossRef]
8. Kerr, R.; Birdgeneau, J.; Batt, B.; Yang, P.; Nieuwenburg, G.; Rettger, P.; Arnold, J.; Bronicki, Y. The Long Lake project–The first field integration of SAGD and upgrading. In Proceedings of the SPE International Thermal Operations and Heavy Oil Symposium, Calgary, AB, Canada, 4–7 November 2002; p. SPE-79072.
9. Carpenter, C. Horizontal Steam Injectors in The Kern River Field. *J. Pet. Technol.* **2018**, *70*, 82–83. [CrossRef]
10. Cui, G.; Liu, T.; Xie, J.; Rong, G.; Yang, L. A Review of SAGD Technology Development and Its Possible Application Potential on Thin-Layer Super-Heavy Oil Reservoirs. *Geosci. Front.* **2022**, *13*, 101382. [CrossRef]
11. Speight, J.G. *Enhanced Recovery Methods for Heavy Oil and Tar Sands*; Gulf Publishing Company: Houston, TX, USA, 2009.
12. Liu, S.; Wang, X.; Gao, Y.; Yang, L.G.; You, S.J. SAGD Process with The Combination of Vertical and Horizontal Wells in Super-Heavy Oil Reservoir. *Pet. Explor. Dev.* **2007**, *34*, 234–238.
13. Chen, S.; Xiang, H.; Li, B.; Xu, B. Geomechanical Dilation Assisted VHSD Process in Altered-Stress Mature Oil Sands Reservoir: Geomechanical Studies and Field Experiences. In Proceedings of the ARMA US Rock Mechanics/Geomechanics Symposium, Santa Fe, NM, USA, 26–29 June 2022.
14. Dong, X.; Liu, H.; Chen, Z.; Wu, K.; Lu, N.; Zhang, Q. Enhanced Oil Recovery Techniques for Heavy Oil and Oil Sands Reservoirs After Steam Injection. *Appl. Energy* **2019**, *1*, 1190–1211. [CrossRef]
15. Prats, M. The Heat Efficiency of Thermal Recovery Processes Resulting from Non-Uniform Vertical Temperature Profiles. In Proceedings of the SPE Latin America Petroleum Engineering Conference, Caracas, Venezuela, 8–11 March 1992; p. SPE 23744.
16. Das, S. Improving the Performance of SAGD. In Proceedings of the SPE International Thermal Operations and Heavy Oil Symposium, Calgary, AB, Canada, 1–3 November 2005; p. SPE-97921.
17. Nasr, T.N.; Law, H.S.; Beaulieu, G.; Golbeck, H.; Korpany, G.; Good, W.K. SAGD Application in Gas Cap and Top Water Oil Reservoirs. *J. Can. Pet. Technol.* **2023**, *42*, 32–38.
18. Peng, S.; Yuan, A.; Jiang, H.; Zhang, S. Cyclic Preheating Test in SAGD Horizontal Wells of Liaohe Oilfield. In Proceedings of the SPE International Oil and Gas Conference and Exhibition in China, Beijing, China, 8–10 June 2010; p. SPE-130948.
19. Guan, W.; Jiang, Y.; Guo, E.; Wang, B. Heavy Oil Development Strategy Under The "Carbon Peaking and Carbon Neutrality" Target. *Acta Pet. Sin.* **2023**, *44*, 826–840.
20. Oil and Gas Journal Group. IHS CERA: Oil Sands GHG Emissions Lower Than Perceived. *Oil Gas J.* **2010**, *37*, 108.
21. Hannouf, M.; Assefa, G.; Gates, I. Policy Insights to Accelerate Cleaner Steam-Assisted Gravity Drainage Operations. *Energies* **2022**, *15*, 86. [CrossRef]

22. Le Ravalec, M.; Morlot, C.; Marmier, R.; Foulon, D. Heterogeneity Impact on SAGD Process Performance in Mobile Heavy Oil Reservoirs. *Oil Gas Sci. Technol.* **2009**, *64*, 469–476. [CrossRef]
23. Li, H.; Wang, Q.; Wu, Y. Current Status and Development Direction of Low-Carbon Exploitation Technology for Heavy Oil. *Energies* **2023**, *16*, 2219. [CrossRef]
24. Govind, P.A.; Das, S.; Srinivasan, S.; Wheeler, T.J. Expanding Solvent SAGD in Heavy Oil Reservoirs. In Proceedings of the SPE International Thermal Operations and Heavy Oil Symposium, Calgary, AB, Canada, 20 October 2008; p. SPE-117571.
25. Zhao, Q.H.; Cheng, H.Q.; Yang, X.C.; Liu, B.X.; Chen, N. Experimental Technology and Application of Multiple Thermal Recovery Development in Heavy Oil Reservoir. In *International Field Exploration and Development Conference*; Springer Nature: Singapore, 2022; Volume 16, pp. 3675–3687.
26. Guo, E.; Jiang, Y.; Gao, Y.; Wang, H.; Wei, Y. Study on Thermal-GAS EOR Method in Depth Extra-Heavy Oil Reservoir in China. In Proceedings of the SPE EOR Conference at Oil and Gas West Asia, Muscat, Oman, 21–23 March 2016; p. SPE-179799.
27. Telmadarreie, A.; Trivedi, J.J. CO_2 Foam and CO_2 Polymer Enhanced Foam for Heavy Oil Recovery and CO_2 Storage. *Energies* **2020**, *13*, 5735. [CrossRef]
28. Shen, D.; Zhang, Y.; Zhang, X.; Wu, S.H.; Li, C.T. Study On Cyclic Carbon Dioxide Injection After Steam Soak in Heavy Oil Reservoir. *Acta Pet. Sin.* **2005**, *26*, 83.
29. Wang, C.; Liu, P.; Wang, F.; Atadurdyyev, B.; Ovluyagulyyev, M. Experimental Study on Effects of CO_2 and Improving Oil Recovery for CO_2 Assisted SAGD in Super-Heavy-Oil Reservoirs. *J. Pet. Sci. Eng.* **2018**, *165*, 1073–1080. [CrossRef]
30. Li, Z.; Lu, T.; Tao, L.; Li, B.; Zhang, J.; Li, J. CO_2 and Viscosity Breaker Assisted Steam Huff and Puff Technology for Horizontal Wells in A Super-Heavy Oil Reservoir. *Pet. Explor. Dev.* **2011**, *38*, 600–605. [CrossRef]
31. Li, S.; Yu, T.; Li, Z.; Zhang, K. Experimental Investigation of Nitrogen-Assisted SAGD In Heavy-Oil Reservoirs: A Two-Dimensional Visual Analysis. *Fuel* **2019**, *1*, 116013. [CrossRef]
32. Yuan, Z.; Liu, P.; Zhang, S.; Li, X.; Shi, L.; Jin, R. Experimental Study and Numerical Simulation of Nitrogen-Assisted SAGD in Developing Heavy Oil Reservoirs. *J. Pet. Sci. Eng.* **2018**, *1*, 325–332. [CrossRef]
33. Tang, X.; Ma, Y.; Sun, Y. Research and Field Test of Complex Thermal Fluid Huff and Puff Technology for Offshore Viscous Oil Recovery. *China Offshore Oil Gas* **2021**, *23*, 185–188.
34. Hein, F.J. Geology of Bitumen and Heavy Oil: An Overview. *J. Pet. Sci. Eng.* **2017**, *154*, 551–563. [CrossRef]