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Review

Green Energy Sources Reduce Carbon Footprint of Oil & Gas Industry Processes: A Review

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Abstract

In recent years, the oil and gas sector has been moving towards green production methods to achieve net-zero emission goals. Governments and corporations have started large-scale initiatives to deploy advanced technologies to reduce carbon footprints and prevent global warming. Herein, we have explored the emerging techniques and methods used in reducing the effects of gas emissions in the oil and gas industry. The transition process from hydrocarbons to renewable energy resources, including solar thermal applications for EOR, thermal energy extraction from hydrocarbon reservoirs, hydrogen generation strategies, and CO_2 EOR and storage applications, has also been discussed. Literature information and publicly available data have paved the way to provide the theoretical background, the rationale of use, screening and selection criteria, challenges, and workarounds for these novel energy sources. Systems to integrate green methods into oil and gas processes appear in detail, from screening to implementation. Then, the technical information for integrating these resources under multiple conditions that affect the system's efficiency, such as weather, seasonal temperature changes, wind, and solar exposure, have been investigated. Moreover, added benefits of such incorporation strategies, such as improved economics with minimal effects on capital intensiveness or other burdens on the overall economy, have also been addressed. The transition from fossil fuels to renewable and greener energy resources provided the underlying motivation for this study.

Keywords

Green energy sources; reducing carbon footprint; oil & gas industry; energy extraction in fluid production & fluid circulation; hydrogen generation; carbon sequestration

1. Introduction

Global warming prompted by gas emissions is in a critical stage that could cause significant environmental consequences. The main target of scientists, governments, and countries is to keep the global temperature increase below 1.5°C, as suggested by UNCC [1]. Hydrocarbon burning is the primary source of global warming. Thus, for example, emerging trends for transportation systems have increasingly relied on electric vehicles and hybrid systems. This trend signals a global U-turn from hydrocarbons to renewable energy sources, such as wind, solar, hydro, geothermal, and nuclear. However, the energy transition will not be as rapid as once expected. For example, Matek and Gawell [2] point out that most renewable energy resources are not currently capable of constituting a power baseload. This reality implies that they might not meet the energy requirements of heavy industries unless the technology for batteries used in energy storage is significantly more mature.

Out of all the greener energy sources, nuclear and geothermal have the most significant potential for achieving baseload power. However, oil products continue to help produce almost all equipment, tools, and goods needed for most human activities. Thus, cutting off oil production cannot be achieved in a brief time, but the rise in the usage of renewables will directly affect the increase of oil production soon. These dynamics have made National Oil Companies (NOCs), governments, and large private oil companies appear more prominently in the energy transition stage, as Lu et al. [3] articulated, through diverting new energy investments from hydrocarbons to renewables. Some examples of this participation by actors in the energy transition process are using renewable energy to complement hydrocarbons, developing hybrid systems, and supplying power to offshore platforms.

Innovative technologies have appeared to mitigate hydrocarbon-based gas emissions in the oil and gas industry. Some get directly used for CO_2 storage, while others complement practices like reservoirs' Enhanced Oil Recovery (EOR), as discussed by Temizel et al. [4]. For example, depleted hydrocarbon wells offer prospects for heat extraction with the goal of electricity generation and direct-use applications. In contrast, solar thermal energy used for heavy oil recovery is an emerging technique for EOR applications. Moreover, solar radiation-based energy can generate steam for thermal oil recovery. This method is currently in a developmental stage, being applied in natural gas deficiency regions. Still, technical and economic merits dictate their applicability across different areas.

Hydrocarbon wells get depleted in their lifetime. A new trend to support their life for longer has been to retrofit these wells by extracting heat from the geothermal gradient of specific regions. Given the availability of prospective wells of this type, the cost of these projects is relatively smaller than hydrocarbon projects. Indeed, the design of the heat exchanger and operating parameters, such as the circulation rate of working fluid and the type of heat exchanger, play an essential role in the performance of the process [5]. Moreover, Mirabolghasemi et al. [6] find support for other variables like the geothermal potential of the formation, well depth, and other working fluid circulation parameters.

On-site hydrogen generation in heavy-oil recovery processes and unconventional reservoirs is an innovative process that significantly reduces the cost of generating hydrogen while utilizing an environmentally friendly method. Additionally, in-situ hydrogen generation through the gasification of bitumen reservoirs is a new concept advanced for clean energy production. This process includes a water-gas shift reaction to produce energy from depleted heavy oil reservoirs, converting the remaining hydrocarbon into hydrogen fuel cells within the reservoir. The gasification of bitumen underground enables operators to sequester the CO_2 produced on-site. At the same time, this process requires less energy to have both energy production and CO_2 sequestration simultaneously. Alberta, Canada, is the most famous region for hydrogen generation from bitumen gasification, as Kapadia et al. [7] articulated.

Meanwhile, geological sequestration of CO_2 has shown to be one of the most effective methods for emission mitigation. Physical trapping is associated with stratigraphic, structural, and hydrodynamic trapping. In contrast, as Mukherjee and Dutta [8] suggested, geochemical trapping entails mineralization and solubility. Despite their promise, large-scale field applications of carbon trapping follow various economic and technical evaluations that need close scrutiny. Therefore, CO_2 storage remains a challenging topic requiring extensive experimental and simulation-based studies. According to the International Energy Agency or IEA [9], carbon capture and storage (CCS) technologies are considered an essential part of the strategy for gas emission mitigation. That said, CO_2 injection only for storage purposes is economically challenging, a reality that has prompted governments and operators to consider CO_2 sequestration as a complementary tool to EOR projects. CO_2 is also used as an injected gas in huff-n-puff for shale-oil production projects. CO_2 has five to ten times more adsorption capacity than methane (CH_4), replacing CH_4 in shale gas reservoirs. Thus, methane production can ease CO_2 sequestration.

In this work, we assess the emerging techniques applied to mitigate the effects of gas emissions in the oil and gas industry. The study includes a comprehensive examination of the energy transition process from oil and gas to renewables through solar thermal applications for EOR, CO_2 storage applications, and in-situ hydrogen generation strategies. As a path forward, we evaluate green applications regarding their technical and economic perspectives.

2. Solar Thermal Applications for Heavy Oil Recovery

Steam generation from solar energy for thermal EOR processes is an emerging technology with significant economic and environmental considerations. This method is needed, especially in gas-burning steam generation applications. Solar steam generation is now in play in California and the Middle East. California's emissions regulations allow solar steam generation at a lower cost than other methods. At the same time, the scarcity of natural gas in the Middle East makes solar energy more attractive than conventional steam generators. Therefore, discerning the viability of using solar energy to generate a steam alternative to traditional steam generators becomes imperative. Various simulations, experiments, and field applications help assess the applicability of these methods.

Solar steam generation has the potential to be a large-scale energy source for thermal EOR. The optimal solar configuration depends on several parameters, such as land availability, local environmental conditions, and reservoir injectivity. The solar steam generator is unavailable based on seasonal variations and daylight performance. Figure 1 shows a glass house that works with trough technology, integrating solar steam into EOR processes. Kundalamcheery and Chintala [10] advanced the glasshouse parabolic trough collector (GPTC) technology to avoid damage from windy and dusty climates.

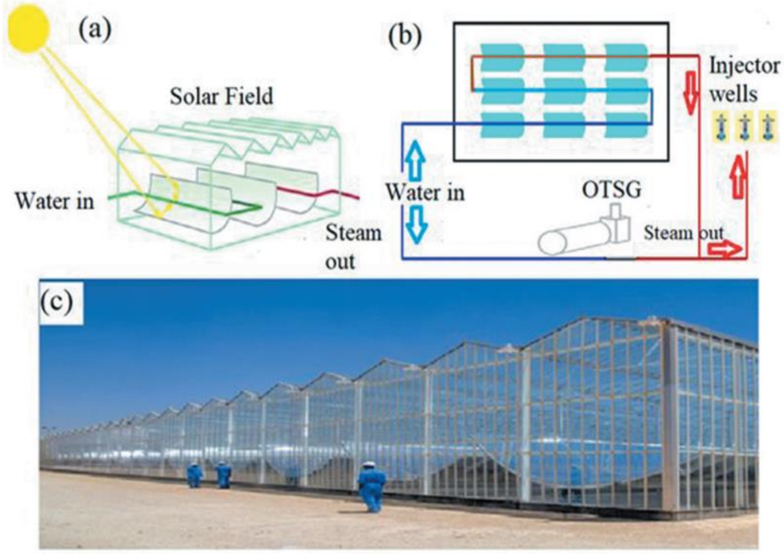

Figure 1 Glass house enclosed trough technology; (a) Working principle, (b) Integration of solar steam with once-trough steam generator (OTSG) and injector wells, (c) Live plant photograph [10].

The authors used a live plant in the Sultanate of Oman as a case study, ultimately uncovering that the energy received from the Sun was in the range of 4.8 to 6.15 MW, while the valuable energy for steam generation to be used in EOR processes was between 2.42 and 3.21 MW. They found that the reflectivity of the collector surface, the absorptivity of the receiver tube surface, and the transmissivity of the glasshouse, among other factors, can affect the overall energy performance. Finally, the quantity and quality of steam are inextricably linked to the solar irradiance received; therefore, such costly projects can only work in regions where the Sun radiates the most.

Meanwhile, Venezuelan heavy oil reservoirs are treated with steam injection to increase oil recovery. Yegane et al. [11] studied solar steam-generated steam injection in Hamca, a Venezuelan extra-heavy oil reservoir. Instead of using the steam generator for extra-heavy oil reservoirs, the authors proposed a solar steam generation system. A commercial thermal simulator helped evaluate the performance of the steam injection process during five years of production. In conclusion, this work proposed steam generators to utilize mainly solar and fossil fuel energies to compensate for the energy needed for steam generation at night. Nevertheless, they found that the 100% solar method without nocturnal steam injection yielded the highest NPV, a method that turned out to be a green EOR process.

Solar steam generators have steadily replaced fuel-fired steam technologies, partly due to regulations incentivizing more environmentally friendly processes. The work of Winslow [12] reported different combustion sources in California (Figure 2), showing that more than half of combustion originates from steam generation. This shift was promoted by a regulation passed in 2006 through the Global Warming Solution Act, which helped initiate one of the first greenhouse gas (GHG) reduction programs.

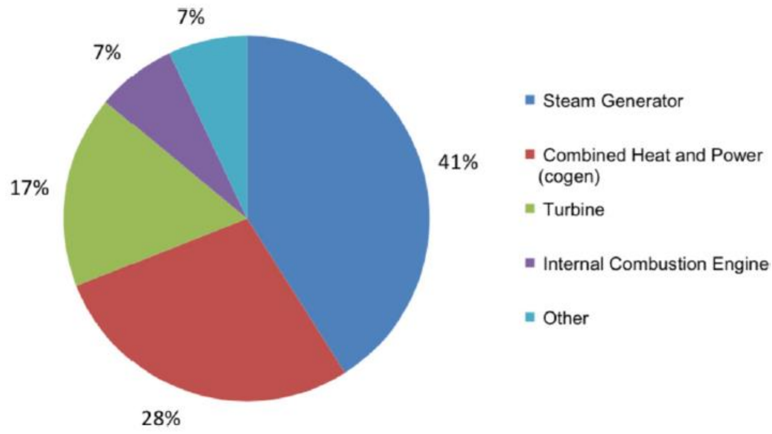

Figure 2 Combustion Sources in California Oil & Gas Production [12].

In a typical solar steam generator project, meeting the following considerations is vital:

- The solar blocks require placing close to injectors to minimize thermal heat loss across the steam pipes.
- Pipe diameters need optimization processes to support steam quality at flow lines.
- Steam pressure at different injection points needs monitoring to ensure steam headers operate within the design boundaries.

To quantify the performance of the solar-generated steam injection for added oil recovery, researchers have relied on varying reservoir simulation tools. For example, Sandler et al. [13] performed a simulation-based study to delineate the economics and a life-cycle assessment of the solar-generated steam for oil recovery, using the San Joaquin Valley in California as a case study. The simulation results with continuous but variable rates were then compared with those from the Tulare Sand steam flood project's baseline project. The authors reported that the observed daily cyclic fluctuations in steam injection rates have no significant impact on recovery. However, the system with no natural gas backup showed seasonal variation explained by solar radiation changes. Financial results show that all-natural gas cogeneration and 100% solar fraction scenarios had the most significant and nearly equal NPV of \$12.54B and \$12.55B, respectively, between 1984 and 2011.

Meanwhile, Agarwal and Kovscek [14] evaluated the viability of a solar thermal steam generation system with natural gas backup for thermal EOR using coupled geomechanical reservoir simulation methods. They investigated the role of geomechanics during continuous steam injection with variable rates. Rock deformation occurs due to stress variation related to steam injection. Then, van Heel et al. [15] studied the impact of daily and seasonal cycles in solar-generated steam on oil recovery. They used analytical modeling and thermal reservoir simulations to investigate the recovery factor of the process. Additionally, the study showed that one could ignore the impact of a daily cycle in steam injection in a fractured reservoir with a fracture spacing larger than one meter. Furthermore, the authors found that the oil recovery does not change with the injection rate if the cumulative amount of steam is the same for fractured and non-fractured reservoirs, as Figure 3 displays.

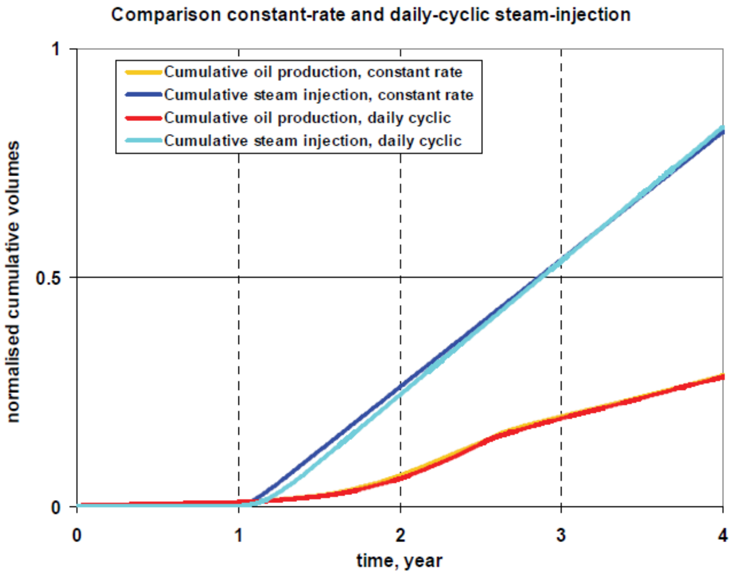

Figure 3 Comparison of constant and cyclic steam injection [15].

The Athabasca region in Alberta, Canada, offers a limited natural gas environment for bitumen recovery. Kraemer et al. [16] proposed mid-temperature steam generation processes to stimulate an oil-sand formation, wherein solar radiation supplies steam generation. They studied the feasibility of the cyclic steam injection in terms of both technical and financial viewpoints, with the schematic of the proposed recovery system featured in Figure 4.

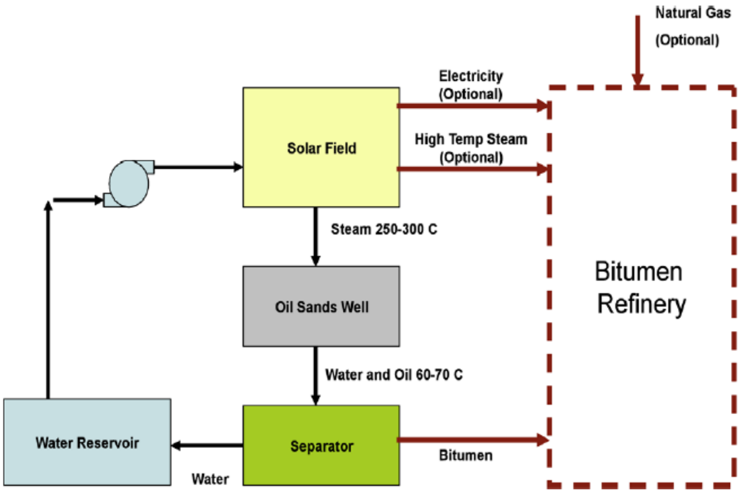

Figure 4 Schematic of proposed recovery system [16].

Solar-generated steam injection projects are economical and environmentally friendly, mainly when deployed in remote areas with a deficiency of natural gas for steam generation via a conventional generator. Operational issues and geographical factors such as drill sites, terrain suitability, and field development plans might affect solar EOR operations. Afsar and Akin [17] present a pilot solar collector system project, which Figure 5 shows. Their findings show that normal insolation of the field location was insufficient to maintain a continuous steam injection.

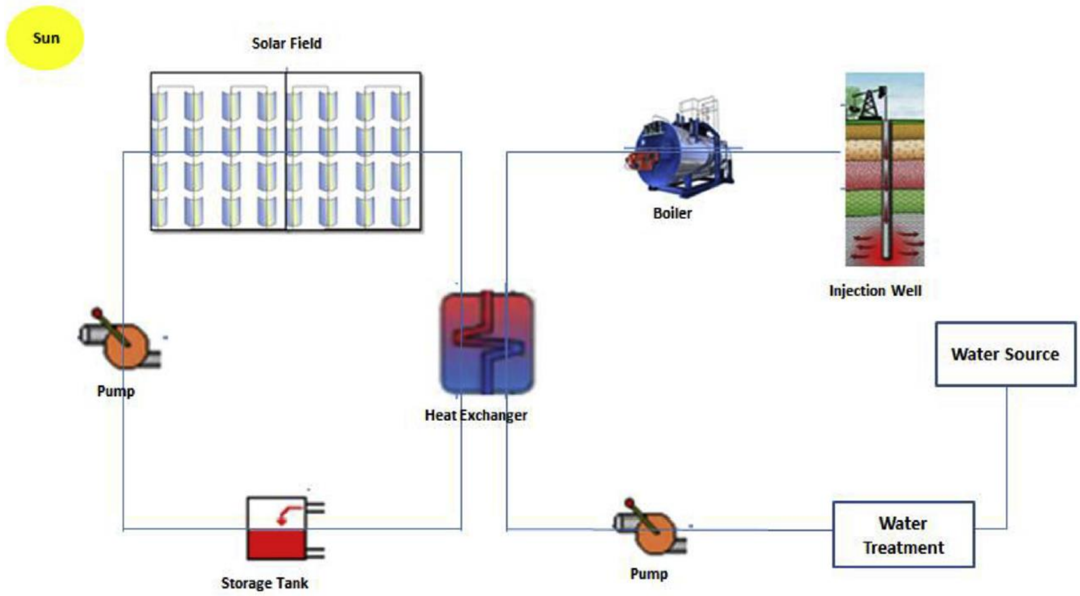

Figure 5 Solar-generated steam injection model [17].

2.1 Pilot Solar Steam Generation for EOR Applications:

The application of solar steam generators has been around for the last several decades. ARCO Solar constructed one of the first pilot projects in California in 1983, with a 1 MW thermal solar steam generation capacity. Meanwhile, the world's first commercial solar EOR installation came from Glass Point Solar for Berry Petroleum in California. After this, Chevron Corp. and Bright Source Energy commissioned a 29 MW thermal steam facility at Coalinga Field, California. The main challenges of these projects at the time were the economic and practical aspects of solar thermal EOR in an oilfield environment.

Due to its large, heavy oil reserves, the literature has found that Oman is one of the most convenient locations for thermal EOR methods. As noted previously, the live plant examined by Kundalamcheery and Chintala [10] show the promise of GPTC methods. In turn, simulations can also theorize the potential of a region and a particular method in achieving EOR with steam injection techniques. Qureshi et al. [18] analyzed the solar potential for the northern field of Pakistan using the TRNSYS software. Examining three different scenarios of injection, one for 12 hours, one for 18 hours, and one for 24 hours, the authors found that all scenarios outperform the burning of natural gas to produce steam.

Solar thermal applications may encounter some obstacles. Here are some relevant items to consider:

- Need tons of water for operation, a problem in desert areas.
- A high amount of radiation and large spaces are needed for solar thermal applications. Solar radiation is not efficient in all regions around the world. Besides, occupying large spaces might be considered a high environmental footprint.
- Solar thermal applications involve hundreds of massive mirrors, which might negatively

impact animal wildlife.
- Although molten salts in tanks provide thermal storage, solar systems are inefficient due to the lack of solar radiation at night.
- High capital costs and expensive maintenance costs are the most significant drawbacks of solar thermal plants.

3. Thermal Energy Extraction During Fluid Production and Circulation

This section features some examples of thermal energy extraction opportunities during fluid production involving oil and gas wells. All produced fluids from deeper horizons offer this potential. Then, we explore the prospect of thermal energy extraction by techniques like reverse circulation, fluid down the annulus, and up the tubing.

3.1 Fluid Production

During oil or gas production, the heat-flow rate associated with the fluid-flow rate can provide a significant opportunity to harness thermal energy. Bhamidipati [19] performed a study on power generation from waste heat coming out of oil and gas wells. Figure 6 displays the main findings. The study focused on the abandoned Volve field in the North Sea, where the author explored the theoretical potential of the site during its active period. Figure 7 shows the basic features of the Volve field as well as the historical performance of one of its wells.

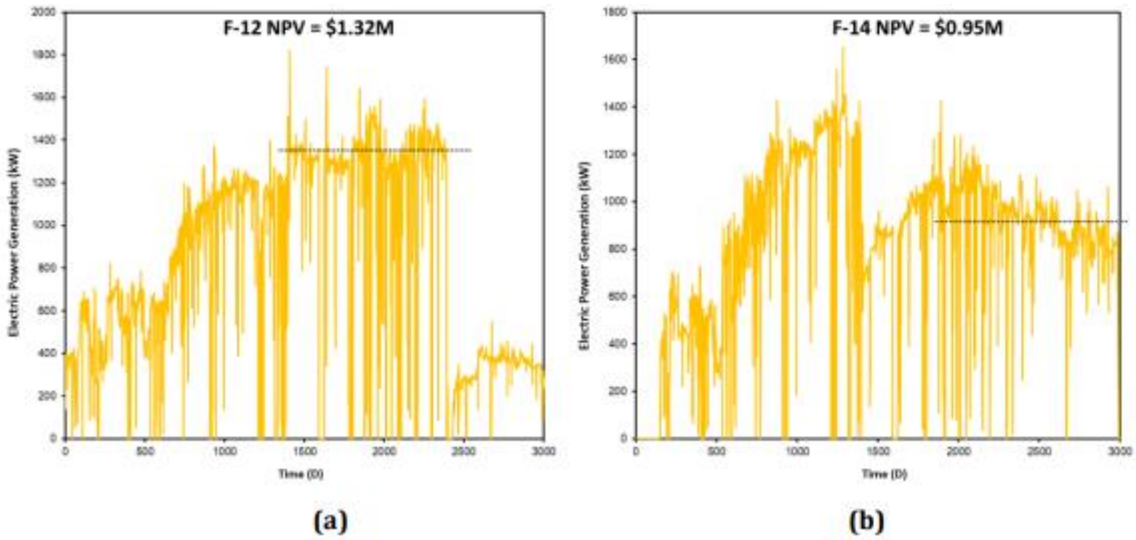

Figure 6 Power generation from produced fluids (a) F-12 well, (b) F-14 well [19].

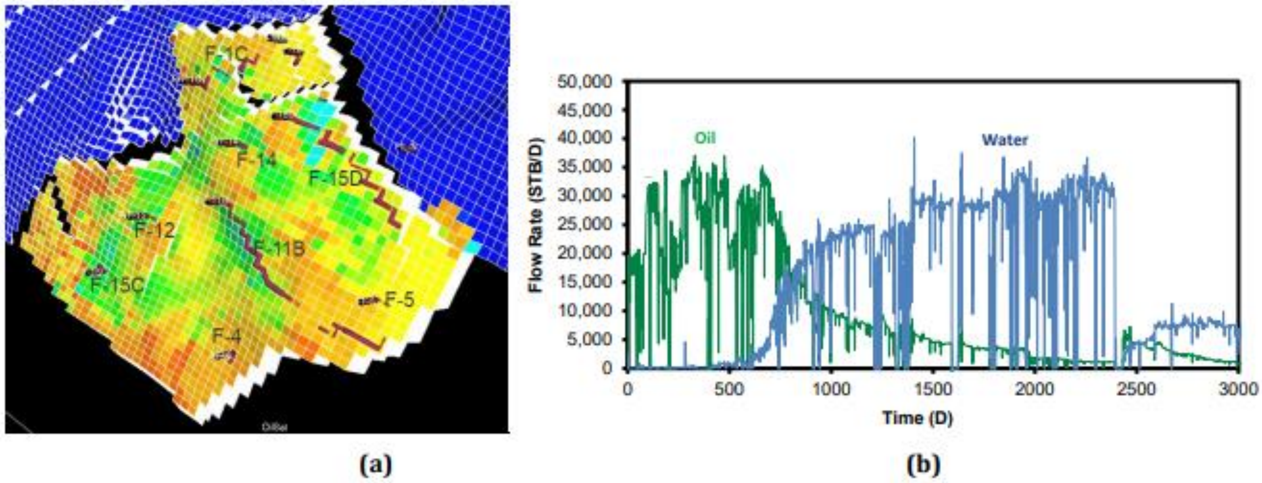

Figure 7 Volve field's numerical model (a), the historical performance of F-12 well (b) [19].

Additionally, the temperature of the reservoir is around 106°C. Given these conditions, a binary power plant using an organic Rankine cycle could convert thermal energy into electricity with about 10% efficiency. A schematic of this sort of plant appears in Figure 8 [20]. Ultimately, the study found that the electric power generation potential from the Volve field is 3.1E5 MWh, corresponding to the electricity consumption of about 29,843 homes.

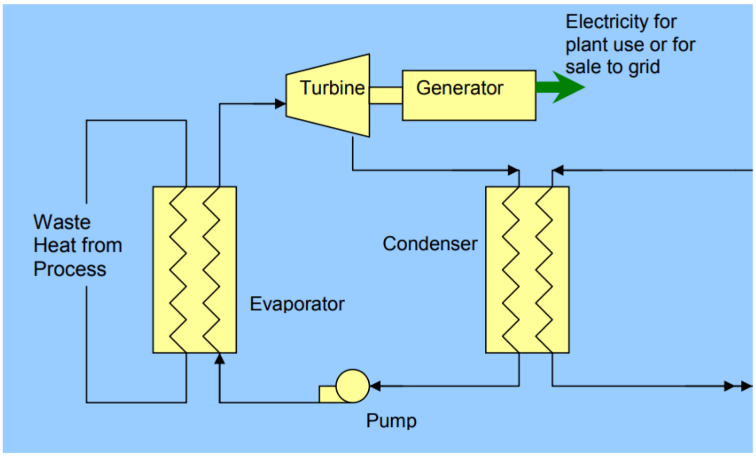

Figure 8 Binary power-plant schematic [20].

Let us point out that gas wells also provide a similar opportunity for energy extraction from produced fluids. The following paragraphs illustrate how one can explore the potential value proposition upfront. This first field example is from an Australian deepwater prospect involving four gas wells, as Kabir et al. [21] discussed. A coupled analytical reservoir/wellbore modeling approach allowed the reproduction of the measured temperatures at different depths in each wellbore. Figure 9(a) illustrates the importance of the actual temperature of the source rock that dictates the flowing-temperature gradient, in this case, up to the mudline for dry-gas wells. Even though the production of Well-3 is much higher than the three others and occurs at a much higher rate, the fluid's origin becomes the focal point in delivering the energy to the wellhead. In other words, Well-4's gas provides the highest temperature, given its depth showing the highest geothermal gradient, as Figure 9(b) exhibits.

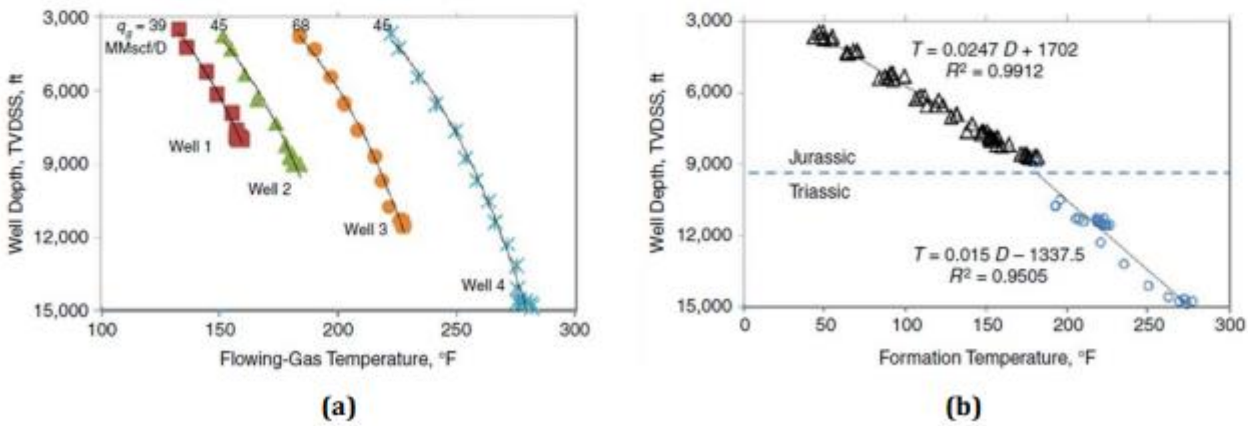

Figure 9 Flowing temperature gradients tied to energy source or reservoir depth (a), estimating geothermal gradient with estimated formation temperatures at various depths (b) [21].

Moreover, Figure 10(a) depicts the depth-wise temperature recordings for Well 3, and later modeling shows the span of temperature traverse associated with each rate, ranging from 15 to 68 MMscf/D. The associated vertical wellbore temperature recordings and the modeling results appear in Figure 10(b). Accordingly, the validation approach with a coupled model paves the way for exploring thermal energy extraction for meaningful energy conversion from each interval. Therefore, we can investigate thermal energy extraction and transformation to power or direct usage from a project's inception to maturity. Additionally, Xu et al. [22] show further improvement in coupled reservoir/wellbore modeling for gas.

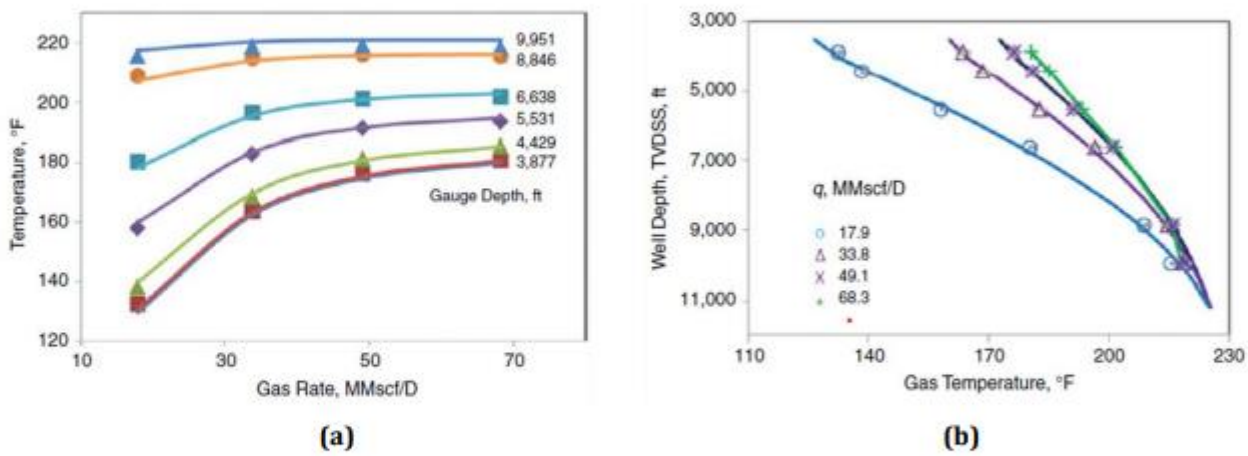

Figure 10 The increase in fluid temperature at each depth reflects increased production rates (a) and transient temperature profiles at various rates for Well 3 (b) [21].

Many abandoned oil and gas wells and actively producing high water-cut wells collectively offer a potential source of clean energy production in countries like the United States. For example, Dahlheim and Pike [23] reported that 823,000 oil and gas wells co-produce hot water with their hydrocarbon output. These wells can generate 3 GW of electricity annually without any CO_2

emissions. A project funded by the National Energy Technology Laboratory (NREL) of the U.S. Department of Energy was among several endeavors featured in this study. The article concluded that this technology becomes attractive when the cost of power is 0.10 US$/kWh or higher.

As we can see, Organic Rankine Cycles (ORC) are one of the most recent technologies using low enthalpy temperatures for electricity generation. The technical and economic perspective of ORC is essential. Eyidogan et al. [24] investigated ORC technologies from the point of view of their technical and financial considerations. The authors used a case study to find that the ORC's payback period for a 1 MW biomass power plant is 2.7 years.

3.2 Fluid Circulation

The high volume of oil extraction from the reservoir increases water cut and rapid oil depletion. Once exhausted, the wells are abandoned or used for water injection. Thus, a new retrofit concept from depleted oil wells for heat extraction is advanced, with its own environmental and economic considerations. Oil wells typically have low reservoir temperatures, suitable for direct heat applications, such as district heating. These projects' technical and financial evaluation is vital to delineate the heat potential and technological developments applied for heat extraction. The work of Nian and Cheng [25] evaluated geothermal heating from abandoned oil wells. They presented a new geothermal heating system using abandoned oil wells with a comprehensive model combining heat transfer and building energy transport, as Figure 11 illustrates. Findings show that the abandoned oil wells could keep the building temperature around 26°C with a water flow rate of 20 m^3/h, while the maximum heating area could reach 11,000 m^2.

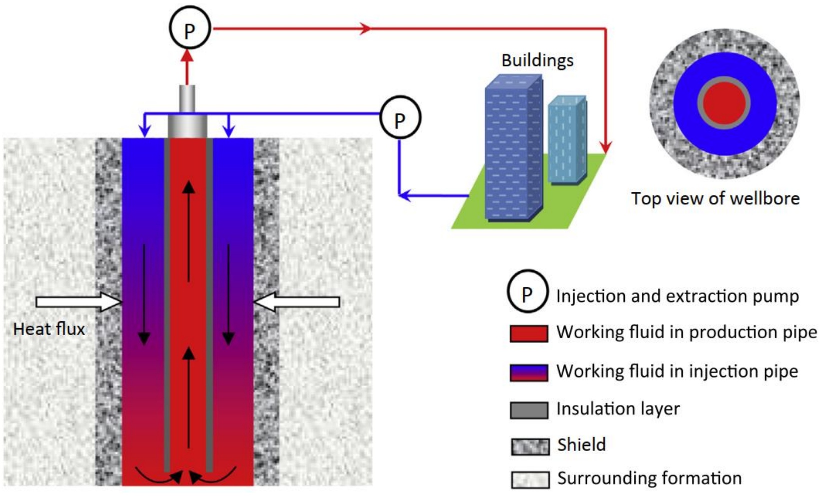

Figure 11 Schematic view of geothermal heating from abandoned oil wells [25].

A feasibility study of geothermal heat extraction is essential to assess if the projects proposed are economically practical. Gharibi et al. [26] used a 3D numerical model of a heat exchanger to evaluate the viability of the geothermal heat extraction from abandoned wells using a U-tube heat exchanger. The sensitivity analyses of the parameters such as mass flow rate, insulation length, fluid inlet temperature, and pipe diameters provided an understanding of their effect on heat extraction. Ultimately, they found that the extracted thermal energy can lead to either electricity generation or direct applications, depending on the fluid temperature.

Likewise, estimating the heat flow rate from the fluid flow rate is critical in designing a downhole heat exchanger. Al-Saedi and Kabir [27] presented a simplified analytical model for fluid flow rate and provided a specific heat flow rate by incorporating the Joule-Thompson effect. Similarly, Sharma et al. [28] provided further insights into exploring the new prospects with designed wells to generate hot water for direct use to meet various industrial needs. Also, generating thermal energy at a higher temperature (greater than 80°C) for indirect use is possible for power generation. More recently, Al-Saedi et al. [29] proved the efficacy of a cyclic circulation strategy to preserve near-wellbore geothermal gradient for improving energy extraction efficiency.

As Figure 12(a) shows, the stepwise circulation strategy minimizes the change in the near-wellbore formation temperature. The resultant bottomhole fluid temperature and heat flow rate to ensure a stable wellhead fluid temperature range, as shown in Figure 12(b), leads to an improved power generation strategy. In contrast, continuous fluid circulation generates a precipitous decline in wellhead fluid temperature, leading to a severe decline in power output, requiring a long shut-in period. Lastly, the work of Nian and Cheng [25] showed that a four-month circulation period requires an eight-month shut-in period to recoup the initial formation temperature due to excessive cooling. Also, as Figure 13 shows, the geothermal gradient dictates the power output, regardless of the flow/shut-in periods.

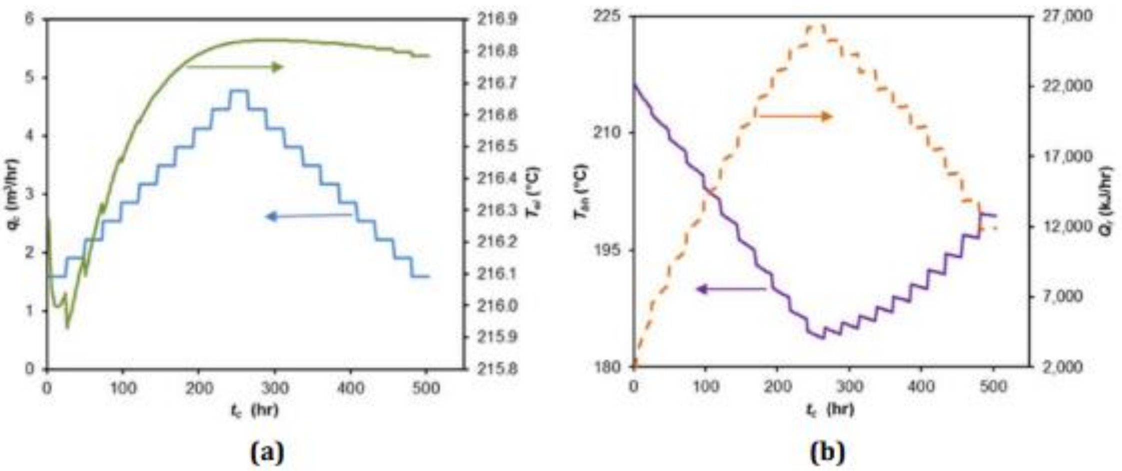

Figure 12 Stepwise fluid-circulation rate profile triggers minimal changes in T_{ei} (a), and enhanced therm. energy output (b) [29].

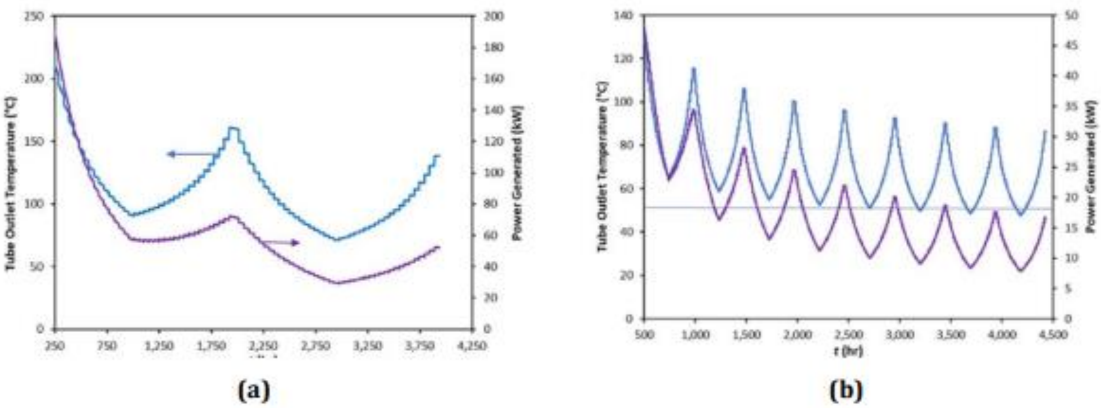

Figure 13 A high-geothermal system (0.055°C/m) generates more power (a) than in a low-g_T system (0.033°C/m) (b) [29].

Depleted CO_2 reservoirs are also potentially had significant energy to recover through hot water production. Aydin and Merey [30] proposed a new method of supplying energy production from gas wells using Electrical Submersible Pumps. The authors used Monte Carlo simulations to assess the potential of geothermal energy production from depleted gas fields, as shown in Figure 14. The Dodan CO_2 field study showed that 4.80 MW of thermal power is possible over 30 years.

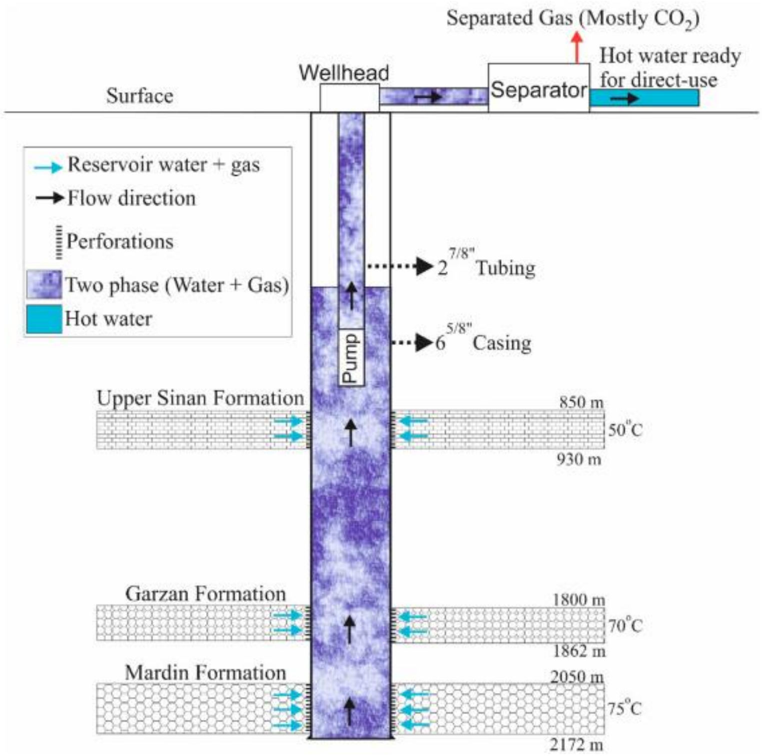

Figure 14 A wellbore scheme for geothermal energy extraction from the Dodan CO_2 field production interval [30].

Furthermore, a closed-loop heat exchanger can significantly aid heat extraction from abandoned oil and gas wells. Kohl et al. [31, 32] explored this concept numerically and experimentally by testing coaxial and double pipe heat exchanger designs. In their earlier work, they found that the heat exchanger plant Weissbad yielded much lower temperatures than expected after the first two years of operation, primarily due to design and construction drawbacks. Meanwhile, in their 2002 work, using data simulations from the history of the production of the borehole heat exchanger (BHE) plant at Weggis, the authors concluded that low use could increase so that production could reach up to 200 kW. One can reach this goal by improving the conditions of the central pipe and a better accounting of the heat transport in the rock matrix.

Likewise, Harris et al. [33] studied the implications of the heat extraction of geothermal energy by using numerical methods. They proposed to install heat exchangers in abandoned vertical oil and gas wells to solve the cost of drilling. As for practical solutions, single vertical well heat exchangers may be a viable choice, as shown in Figure 15. However, their proposal for creating two adjacent directionally drilled wells connected to produce a continuous loop saves piping costs and decreases heat and frictional losses.

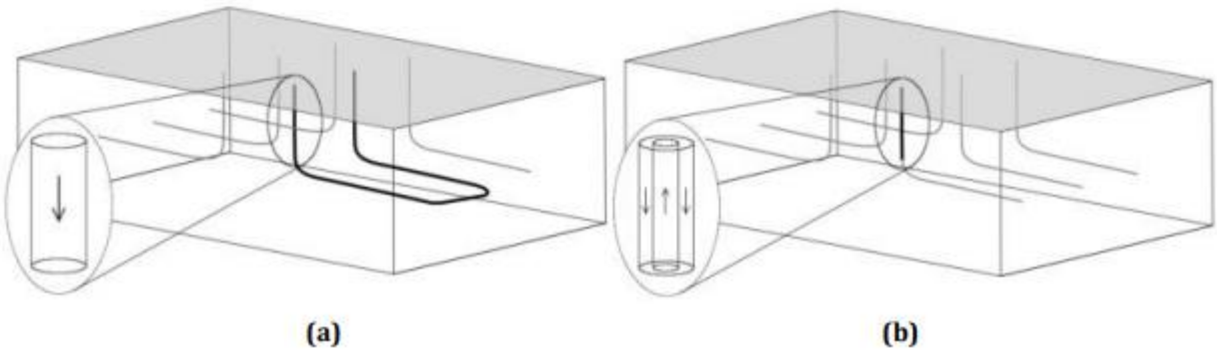

Figure 15 (a) Directionally drilled well with double pipe heat exchanger in vertical section vs. (b) Connected directionally drilled wells with continuous loop [33].

Despite the various advantages of extracting thermal energy from oil and gas wells, the fluid-circulation method has a few drawbacks in repurposed wells. That is because both well depth and the formation's geothermal gradient are vital parameters. Here are some relevant items to consider:

- A small wellbore diameter and depth of conventional oil and gas wells might restrict the size of downhole heat exchangers.
- Geothermal regions are restricted to the ring of fire and tectonically active areas. Therefore, an average geothermal gradient may not be applicable for shallow-depth wells for power generation but may be suitable for direct use in various industries.
- Heat extraction is limited with wellbore surface area in the reservoirs with low water production.

4. Hydrogen Generation from Flaring Gases and In-Situ Hydrogen Generation in Heavy Oil Recovery Processes and Unconventional Reservoirs

Flaring gases causing gas emissions relate to crude oil extraction. This gas is burned, especially in offshore regions where limited infrastructure exists. According to Global Gas Flaring Data published by The World Bank, around 144 bcm of natural gas (or 382 million tonnes of CO_2) emissions occurred in 2021. Most flared gases are from Iraq, Iran, the USA, Algeria, and Venezuela. Methane pyrolysis is a process of converting methane into hydrogen and solid carbon. H_2-Industries proposed using ISO container tanks to store clean hydrogen produced from flare gas [34].

In-situ hydrogen generation by gasifying bitumen reservoirs is a new concept developed for clean energy production. This process includes a water-gas shift reaction to produce energy from depleted heavy oil reservoirs by converting whatever remaining hydrocarbon is left in the reservoir into hydrogen fuel cells. For example, Kapadia et al. [35] investigated the potential of hydrogen generation from in-situ combustion of Athabasca bitumen, relatively dirty fuel and feedstock oil, in Alberta, Canada. The authors found that production is low under temperatures below 200°C, regardless of well pressure. Therefore, temperature is a more critical factor for hydrogen generation.

In addition to generating a clean energy carrier, the gasification of bitumen underground also enables operators to sequester CO_2 in the reservoirs. Plus, these processes coinciding requires less energy than performing them separately. Hallam et al. [36] reported the continuous hydrogen generation (20 mol%) resulting from an in-situ combustion pilot at Marguerite Lake, Alberta, Canada. Figure 16 shows that fossil fuels can generate hydrogen at different efficiencies based on pressure, temperature, and catalysts. Partial oxidation of the hydrocarbon produces hydrogen in the absence of catalysts, while the un-catalysts process appears preferable for reservoirs that are difficult to carry catalysts in tiny pores.

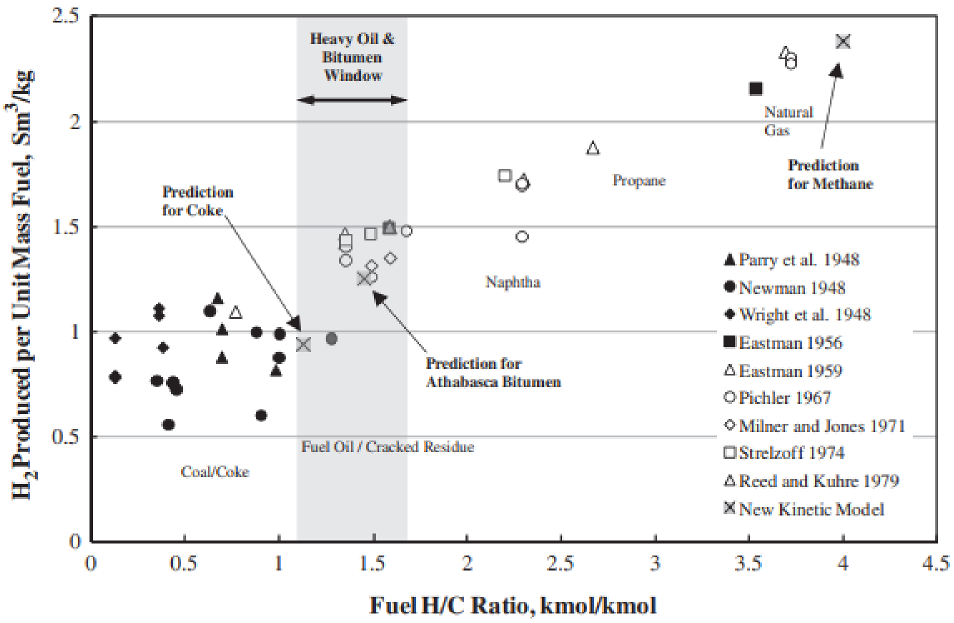

Figure 16 Hydrogen generation yield from various fossil fuels [36].

Kapadia et al. [37] studied the process design for in-situ bitumen gasification for Canada's Athabasca deposits. Most of the bitumen is converted into synthetic crude oil using hydrogen in these processes. In turn, the required hydrogen produces from steam through reforming methane and through in-situ gasification of bitumen. This latter procedure is more efficient and environmentally friendly than the former, yet in-situ bitumen gasification requires an optimization process of hydrogen generation and bitumen production. The authors discussed a field-scale pilot run at Marguerite Lake, where more than 20 mol% of the produced gas was hydrogen. They performed a numerical study on the steam-oxygen cyclic injection process. Figure 17 shows the temperature changes at the end of each injection phase during the steam oxygen cyclic injection. During this process, the steam zone temperature reaches 450°C and moves outward from the injection well. The study found that the energy produced per unit invested for the in-situ gasification process was more significant than the conventional recovery process, with less than half the water usage.

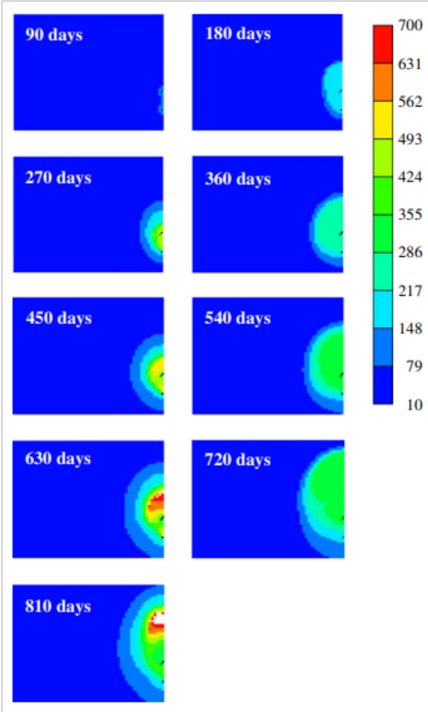

Figure 17 Temperature distributions at the end of each injection period [37].

Additionally, Kapadia et al. [7] estimated the heavy oil and bitumen reserves in Alberta, Canada, to be about 1.7 trillion barrels. The produced oil sands and bitumen get converted into synthetic oil with a specific gravity of 31 to 33 ^{o}API, a process that requires hydrogen obtained through steam reforming methane. The authors offered in-situ hydrogen generation as the potential energy-efficient and environmentally friendly method, reporting that 21 MMm^3 of hydrogen becomes necessary for upgrading 125,000 m^3 of bitumen per day in the oil sands.

In-situ conversion of hydrocarbon reserves into hydrogen can be a breakthrough for the accumulation, storage, and production of commercial hydrogen as a clean energy resource. Surguchev et al. [38] proposed a novel concept, including injection of steam and air, as well as nano-sized super-active catalysts for on-site hydrogen generation in hydrocarbon reservoirs, leading to its storage. The main feature of a nano-sized super-active catalyst is that it has much higher activity than traditional heterogeneous catalysis. The schematics of the proposed method appear in Figure 18. This application aims to avoid energy usage needed for reducing carbon emissions and CO_2 handling processes, such as compression and transportation.

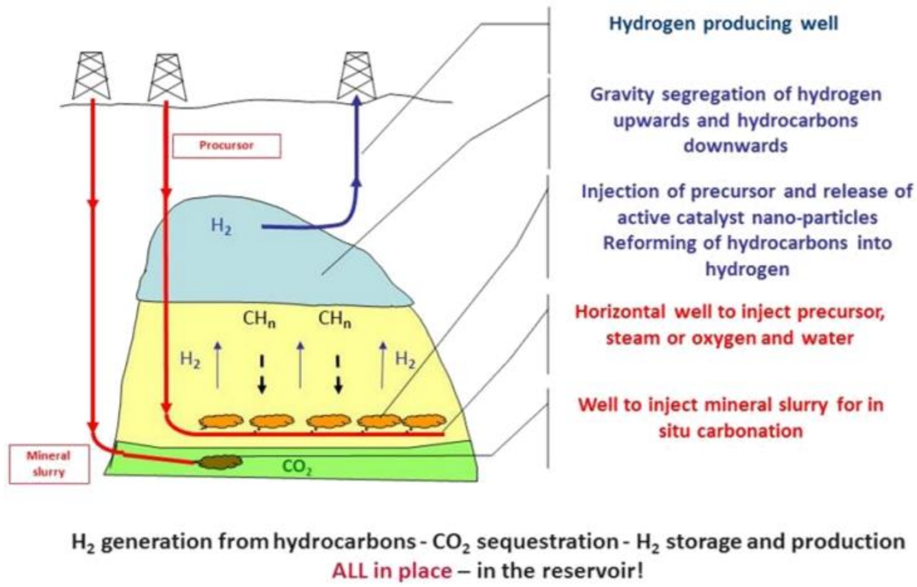

Figure 18 Schematics of the proposed in-situ steam reforming [38].

According to the authors, generally, 20-30% of the initial gas in place remains unrecovered from the reservoir. This in-place gas corresponds approximately to 15-20 billion Sm^3 methane, translating into 1 to 2 million tons of potential hydrogen production. The steam reforming and catalytic cracking reactions for this experiment appear below:

$$CH_4 + H_2O = CO + 3H_2 - 206\frac{kJ}{mol}$$

$$CO + H_2O = CO_2 + H_2 + 41\frac{kJ}{mol} \qquad \text{(steam reforming)}$$

$$CH_4 \rightarrow C + 2H_2 - 75\frac{kJ}{mol} \qquad \text{(catalytic cracking)}$$

The challenges of the in-situ hydrogen generation could be listed as follows:

- In-situ hydrogen generation is not efficient in low-temperature reservoirs.
- The steam injection might be inefficient in deep reservoirs due to energy loss to surrounding formations during the injection.
- Catalytic processes are limited in the choice of feedstock to gaseous, sulfur-free hydrocarbons with a low-boiling point.

5. CO_2 EOR and Storage

Underground CO_2 injection has different applications, such as CO_2 underground storage for emission mitigation, EOR, and hybrid applications. The geological sequestration of CO_2 forms one of the most effective methods for emission mitigation. However, CO_2 storage stays a challenging subject that calls for comprehensive examination through simulations based on historical data and experimental frameworks. Large-scale field applications need displaying to assess the more novel economic and technical considerations.

Various physical and geochemical mechanisms trap CO_2. Physical trapping is associated with stratigraphic, structural, and hydrodynamic trapping. Meanwhile, geochemical trapping entails mineralization and solubility. Both solutions are essential within the strategy for gas emissions mitigation. Recently, Zapata et al. [39] explored the plume dynamics and related storage efficiency over long-term injection and post-injection periods spanning 300 years. Given that the economic viability of CO_2 injection for storage purposes continues to lack support in most settings, governments and operators consider CO_2 sequestration complementary to EOR projects.

A recent and promising carbon mitigation process is the sequestration of CO_2 in geological formations, such as abandoned oil and gas reservoirs, non-mineable coal seams, and deep saline aquifers. Flow simulation of CO_2 in the reservoirs could improve our understanding of the gas behavior in the geological units. The work of Abdelaal and Zeidouni [40] seeks to predict the ultimate storage capacity of sites to store carbon in deep saline aquifers, highlighting injection rate and pressure data as the most optimal predictors of storage capacity. Results confirm that estimated capacities consistently match the estimated values.

Earlier, Hassanzadeh et al. [41] advanced a simple algorithm to compute pressure, volume, and temperature (PVT) data in deep aquifers for geological storage. They found that their black-oil simulator performs better than compositional reservoir simulators because the former provides fast and accurate representations for all the PVT data without the computation-intensive costs of the latter. A real-world application appears in the work of Goodarzi et al. [42], who revisited the feasibility of carbon injection into the Nisku Formation saline aquifer in North America. This study used factors like recorded well-log, well-test, and laboratory measurements to build porosity, permeability, thermal, mechanical property, and profiles for stress. In the end, proper characterization of wells assists in the efforts to retrofit reservoirs to store CO_2 in the most efficient way possible.

Preliminary assessments of the CO_2 storage potential in geological formations include experimental and field measurements and simulation-based studies. Oil reservoirs, considered for enhancing recovery techniques like gas injection, are also good options for CO_2 storage. Geologic characteristics of the formations and working mechanisms during gas injection are critical optimization factors for such expensive projects. Moreover, the possibility of CO_2 leakage is vital to the likelihood of a successful carbon storage strategy; thus, storage security is another vital consideration when examining the potential storing of CO_2 in depleted wells [43]. Relatedly, Zulqarnain et al. [44] highlighted the importance of fault structure heterogeneities as potential challenges to successfully storing CO_2 in a depleted well.

Similarly, Mao et al. [45] discussed the relevance of temperature analysis as a thermal signal for carbon leakage inside a reservoir. When CO_2 leaks due to a drop in pressure inside the well, we observe the Joule-Thomson effect. Then, a preliminary analysis for carbon storage performed by Zhang et al. [46] used the CCS pilot test performed at the H-59 block in the Jilin Oilfield as a case study. The authors found that a successful calculation of the adequate carbon storage capacity requires an increasingly better understanding of two variables: the coverage factor of the well pattern and the sweep coefficient of CO_2 within the well pattern. Including these two factors in their model, the authors estimated tons of storage capacity for the H-59 block.

Additionally, a vital field application of carbon storage during EOR CO_2 injection appears in the offshore regions of the Gulf of Mexico. Koperna and Ferguson [47] investigated the potential for integrated EOR and storage projects in the Gulf, estimating that these ventures could recover up to 5.8 billion barrels of domestic oil while also storing 1.7 million metric tons of carbon dioxide. Due to the prohibitive costs of offshore gas storage projects, joint EOR strategies appear a requirement. Regarding these dynamics, Aschehoug and Kabir [48] reported a field study involving the production of CO_2 with natural gas, followed by surface separation and sequestration into an aquifer. They showed that the fault breach occurred due to excessive injection in a confined space. Meanwhile, for safe disposal of CO_2 and wastewater in saline aquifers or depleted reservoirs, the studies of Phan et al. [49] and Gogri et al. [50] offered practical guidelines for prognosis with real-time surveillance data.

Moreover, the huff-n-puff process is a widely applied production technique put into practice at the Eagle Ford and Bakken shale sites in the U.S. As expected, numerical simulations and experimental studies precede large-scale field applications. Sun et al. [51] studied the application of huff-n-puff in Bakken shale with a discrete-fracture model using CO_2 as an injection gas. The study analyzed sensitivity by varying operating parameters such as cycles, injection rates, and soaking time. The production enhancement changed between 1.3% and 5.9%. Therefore, understanding the molecular diffusion of CO_2 in the reservoir to maximize production from huff-n-puff projects becomes essential.

In addition, Zhang et al. [52] studied gas diffusion in the huff-n-puff during soaking. High permeability and high CO_2 injection rates favor the huff-n-puff process. Earlier, Yu et al. [53] focused on the CO_2 molecular diffusion influences on the performance of huff-n-puff. They reported that tight oil formations with lower permeability, longer fracture half-length, and more heterogeneity favor the huff-n-puff using CO_2. Oil recovery increased with a rise in the number of cycles. They found that the lower reservoir permeability is more helpful for incremental oil recovery from the huff-n-puff application. In addition to numerical simulations, experimental studies were promising for using CO_2 as huff-n-puff gas.

Likewise, Phan et al. [54] showed that cyclic CO_2 injection in unconventional oil reservoirs could occur due to molecular diffusion, as seen in Figure 19. They noted that the early cycles might not yield much incremental recovery, given the low diffusion of CO_2. However, at later times, such as after six years or 14 cycles, when the CO_2 mole-fraction increases over 60%, the incremental oil recovery is about 6%. Over this cyclical period, CO_2 can diffuse into about 90% of the hydraulically fractured stimulated volume.

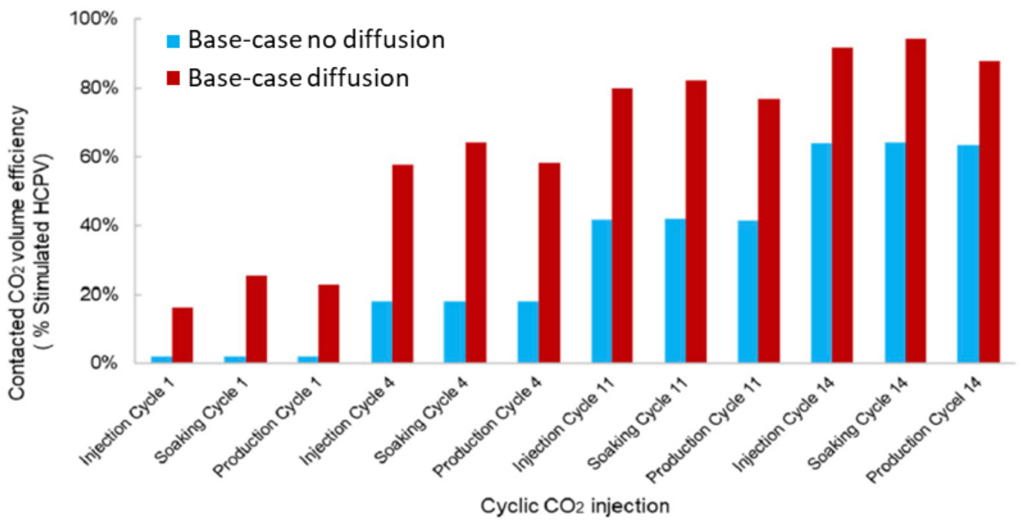

Figure 19 CO_2 diffusion efficiency into the rock matrix of the SRV [54].

As noted previously, Sun et al. [51] studied the effects of CO_2 diffusion on the performance of huff-n-puff projects. Their reservoir system involved fractal and micro-seismic models. The gas expansion appeared as a critical parameter affecting depletion in the reservoir during huff-n-puff. This outcome means that huff-n-puff is more effective when the pressure is below the bubble point. Similarly, Zhou et al. [55] reported a heavy-oil recovery factor, as high as 38%, with the huff-n-puff application using CO_2. The first three cycles appeared to provide the main contribution to oil production.

In turn, Zuloaga et al. [56] studied the performance of CO_2 huff-n-puff using a field-scale numerical compositional reservoir model in the Middle Bakken formation. Matrix permeability turned out to be the most critical parameter, followed by the well pattern and the interaction between fracture half-length and the number of wells. Similarly, Ma et al. [57] conducted an experimental study to reveal the effects of the parameters such as cycle number, permeability, and production pressure during CO_2 huff-n-puff in an ultra-high-pressure tight oil reservoir. Using the nuclear magnetic resonance method, they analyzed the distribution of remaining oil production in different pore sizes. The cumulative oil production increased logarithmically, while the oil recovery cycle decreased as cycles increased.

Also, Wu-Xue et al. [58] studied the role of contact surface area on the miscibility of CO_2 in crude oil. They used large-scale simulation experiments of the CO_2 huff-n-puff to understand the influences of various parameters on oil recovery. They targeted the miscibility of CO_2 in crude oil with multi-fracturing operations. They found that the optimum amount of time for injection was one year, and the optimum soaking time was 30 days. Iino et al. [59] performed an optimization study about CO_2 and field gas injection EOR in unconventional reservoirs using a fast-marching method-based flow simulation, which uses synthetic data to calibrate the double-porosity model. A tornado chart quantified the influences of parameters on incremental oil recovery, as seen in Figure 20.

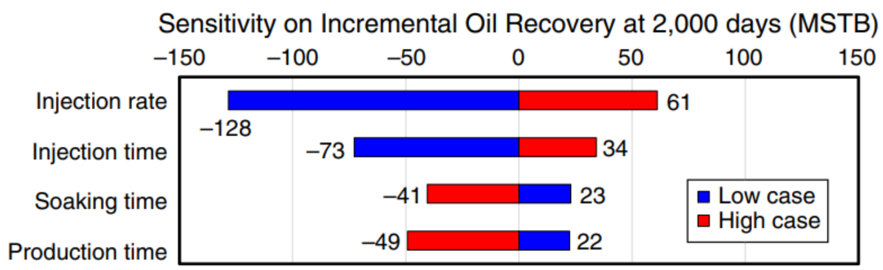

Figure 20 Sensitivity analysis on incremental recovery (hydrocarbon-gas huff 'n' puff) [59].

After optimization, CO_2-enhanced oil production and sequestration in shale reservoirs become a hybrid application. The storage mechanism includes solution, capillary trapping, adsorption, and residual trapping. Mohagheghian et al. [60] reported that carbon dioxide has 5 to 10 times more adsorption capacity than methane, meaning CO_2 can replace CH_4 in shale gas reservoirs. The authors developed a numerical model to simulate multi-component gas flow in shale matrix blocks. The developed model was employed to investigate CO_2 sequestration coupled with methane production. The results were promising, especially for storage applications, far more significant than additional methane recovery. Maximum storage of 90% of the total injected CO_2 was observed in the shale reservoir, wherein 55% of CO_2 got trapped as the adsorbed phase.

Tayari et al. [61] studied the techno-economic CO_2 storage techniques in depleted unconventional natural gas-bearing shale formations. Long-term CO_2 sequestration costs in depleted shale gas formations appeared to be significant cost drivers. The study focused on the transportation of CO_2 from industrial point sources in the Marcellus shale to CO_2 injection. The critical costs relate to CO_2 transport, separation, injection, and monitoring of CO_2 storage. In addition, some of these calculations have the potential for economies of scale, so overall costs should get reduced when spread over multiple wells.

In turn, Figure 21 illustrates two field examples of CO_2 retention capability involving two miscible gas floods. One involves a Carbonate reservoir in West Texas [62], as shown in Figure 21(a), and the other in a sandstone reservoir in Prudhoe Bay, Alaska [63], in Figure 21 (b). RMI represents a site's response after underground gas injection for EOR purposes. The pattern flow efficiency for the first set of wells suggests a 60% CO_2 retention in the reservoir, with the rest produced with oil. This outcome implies that the aggregated ratio of recovery of the wells stabilizes, not dropping at the rate observed at the beginning after a certain amount of CO_2 is injected back into the formation.

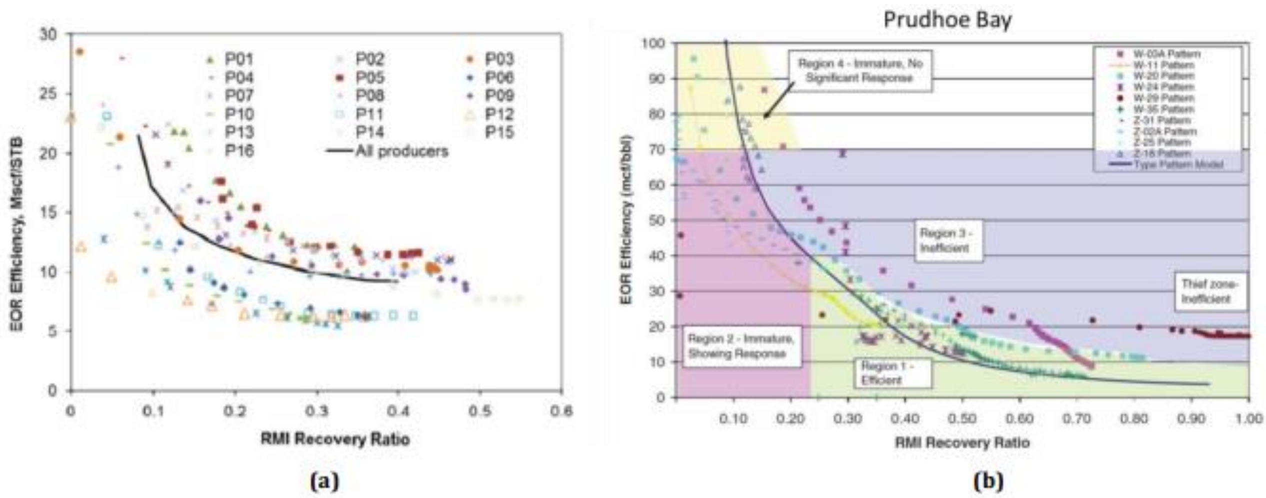

Figure 21 RMI (Returned Miscible Injectant) recovery ratio suggests CO_2 retention in WAG floods in West Texas (a) and in Prudhoe Bay, Alaska (b): (a) about 60% in a miscible gasflood [62] and (b) 30% in the set of wells analyzed by [63].

Meanwhile, although a thief zone appeared in the Prudhoe Bay water alternating gas (WAG) flood, Region 1 shows about a 30% CO_2 retention in this sandstone reservoir. Analysis of surveillance data, such as the capacitance-resistance model offering injector/producer connectivity and the modified-Hall plot showing flow obstacles in injectors, provide clues about the ongoing performance.

Chu et al. [64] used a novel approach for CO_2 sequestration in shale reservoirs. The new method includes flow, diffusion, and adsorption processes of CO_2 in shales. The Laplace transform, followed by Stehfest numerical inversion for a semianalytical solution, evaluated the wellbore pressure and storage capacity. While exploring the CO_2 storage capacity of Bakken shale, the authors found that CO_2 storage capacity is inversely proportional to the storage ratio.

Miscible huff-n-puff cycles in core-flood experiments and numerical modeling showed that the oil recovery factor (RF) ranged from 31 to 56% in Eagle Ford shale, as summarized by Syed et al.

[65]. The same study also showed that miscible huff-n-puff cycles lead to 60% oil RF in the Bakken play; higher permeability led to this outcome. However, some of the reported field trials produced mixed results. Another numerical flow simulation study by Syed et al. revealed that increased cycles (up to four) and injection over 50% pore volume lead to about 6% trapped CO_2 volume [66]. In this context, citing different studies, Du and Nojabaei (2019) presented experimental study results of oil recovery ranging from 8 to 48% for the Bakken and 56% for the Eagle Ford rock samples with CO_2 huff-n-puff. However, most simulation studies showed the oil RF to be about 10 to 15% in these two plays [67].

Enhancing methane recovery with CO_2 injection from shale reservoirs might address the problem of clean energy and environmental considerations related to hydrocarbon production. Displacing CH_4 with carbon is a solution for CO_2 sequestration in shale formations. Pentyala et al. [68] analyzed the feasibility of methane displacement by CO_2 during EGR from calcite-rich shale. They used van der Waals' corrected density calculations to analyze the thermodynamic feasibility of the displacement of CH_4 by CO_2. They found that the adsorption of CO_2 is one and a half times stronger than the adsorption of CH_4 over a representative calcite surface, which is favorable for CO_2/CH_4 displacement.

Louk et al. (2017) reported a successful field study in the Chattanooga Shale formation in Tennessee, wherein over 50% of the CO_2 remained in this gas-condensate reservoir during the 17-month flowback phase [69]. A review study by Du and Nojabaei (2019) reported that the enhanced gas recovery in Marcellus and Barnett shale plays occurs with CO_2 huff-n-puff injection, which is superior to flooding or continuous injection. Besides increasing the gas recovery by over 35%, most injected CO_2 remains sequestered in these simulation studies.

Although CO_2-EOR storage is an effective method for both additional oil production and CO_2 sequestration, it also involves challenges:

- CO_2 storage in oil reservoirs is not implemented if it does not relate to EOR application due to the high project costs.
- CO_2 gases might leak across the permeable faults to the surface due to over-injection, leading to the fault breach.
- CO_2 injection might create an overpressured zone resulting in surface deformations like surface tilting.

6. Energy Transition

Global warming driven by gas emissions has reached a critical stage that could have severe consequences for the environment if the current path does not alter significantly. The main target of scientists, governments, and countries is to keep the global temperature elevation below 1.5°C. Hydrocarbon burning is one of the primary sources of global warming. Thus, new targets have pushed the giant hydrocarbon companies and countries to divert new investments to renewables rather than to new hydrocarbon projects. Additionally, renewable sources like wind and solar can generate upstream, downstream, and midstream energy. This momentum implies that the world is in an energy transition stage from hydrocarbons to renewables. A report from oil and gas giant BP [70] states that the global energy demand will increase by around a third by 2040, with industry and buildings constituting three-quarters of that surge. The fastest-growing energy source will be renewable energy, supplying about half of the energy demand, as Figure 22 suggests.

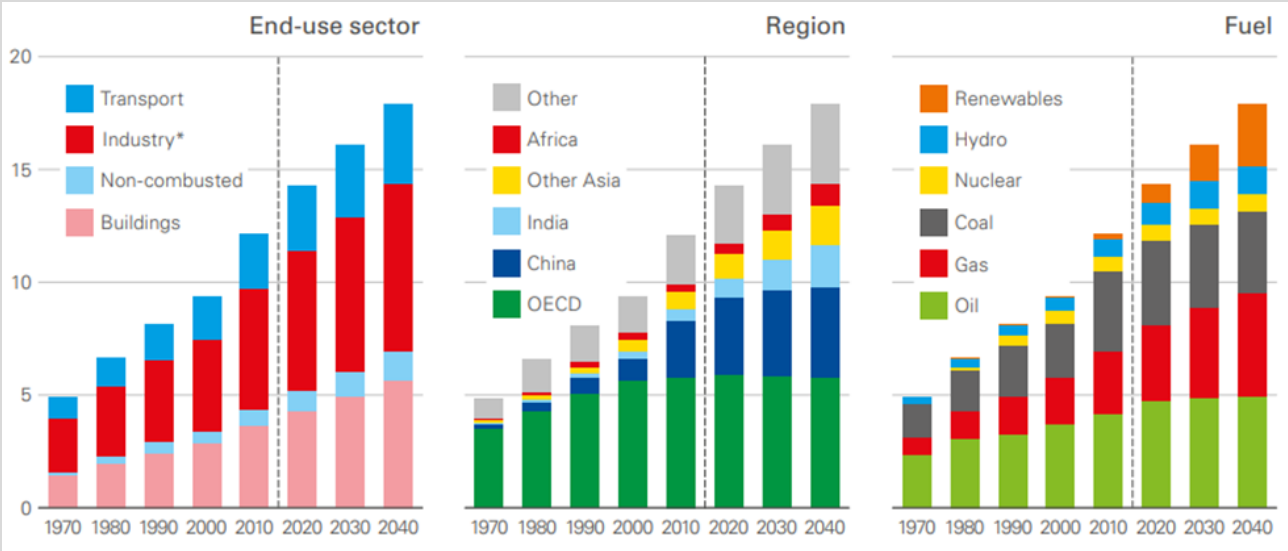

Figure 22 Primary energy demand by sectors, regions, and fuels [70].

Given these developments, several forwarding paths involving governments, private actors, and the citizenry appeared. First, National Oil Companies (NOCs) should adopt their investments in energy transitions, given that the 2019 IEA report [71] suggested that the NOCs operate more than half of the global hydrocarbon wells. However, many NOCs did not appear positioned to adapt to changes in global energy dynamics, at least in the short term [70].

Then, Feder [72] reported one of the essential pieces of evidence for various energy transition strategies from companies. The study highlighted the turning of oil and gas companies to renewables to power their operations, focusing on reducing greenhouse gas emissions, thus changing their brand recognition from oil companies to energy companies [73]. In addition to energy efficiency and reducing flaring, oil and gas players started powering their upstream, downstream, and midstream operations with zero-carbon sources, as Figure 23 exemplifies. Field-based renewable installations appear dependable and cost-effective while having a lower environmental impact than fossil fuel installations.

Figure 23 Power supply to offshore oil platform using wind energy [72].

Similarly, solar energy applications are increasingly complementary to oil and gas industry processes. Temizel et al. [4] evaluated these developments, concluding that solar energy can help generate heat and electricity in the oil regions while treating produced water and refining oil. In this context, Islam et al. [74] presented a list of CCS/CCUS projects started by oil majors, where we highlight the Sleipner and Snøhvit projects led by Eni, which store over a million tons of CO_2 a year. The Quest facility, advanced by Royal-Dutch Shell, converts heavy bitumen into synthetic crude, and the Net Zero Teeside project by B.P. seeks to capture carbon from one of the heaviest polluting industrial clusters in the world.

Likewise, the work of Canbaz et al. [75] examined the status of renewable resources and oil and gas under global supply and demand dynamics. The study reported that renewables in the oil and gas industry are more complements than competitors, opening the door to these technologies working in tandem, as opposed to against each other. An example of the tangible contribution from wind energy in decarbonization processes appears in the work of Chung-Lau and Piriyev [76], who explored floating, production, storage, and offloading (FPSO) units deployed in West Africa and the novel processes to power many of these processes through wind energy. Despite current technology challenges, these processes have the potential to decarbonize several activities that currently utilize fossil fuels. Figure 24 illustrates the complementary work wind turbines perform for offshore sites.

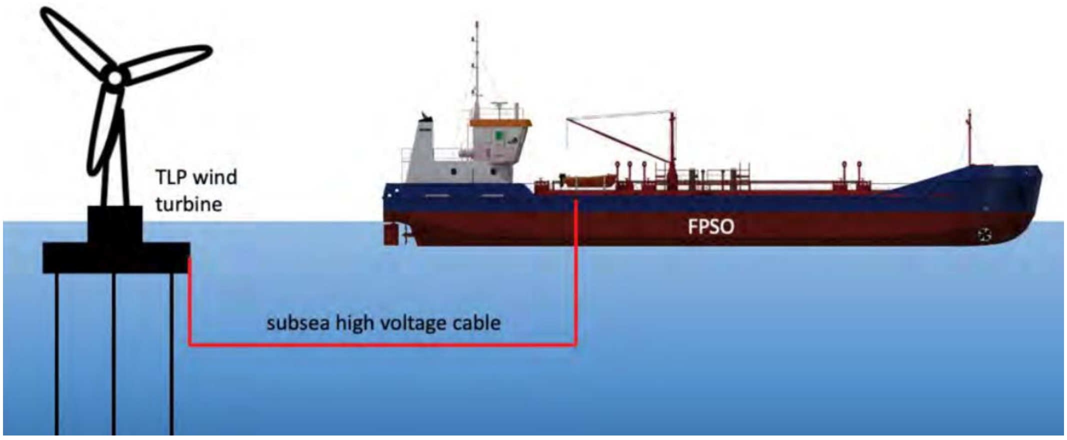

Figure 24 Offshore wind turbine for FPSO power supply [76].

In a similar vein, the work of Ezgi [77] introduces us to novel technologies like ocean thermal energy conversion (OTEC), where the Sun's power can be captured from ocean waters to provide continuous energy for offshore platforms that work with hydrocarbons. This technology provides a 24-hour cycle of energy from the Sun because the temperature difference between the surface level and the bottom of the ocean (where the closer to the surface, the warmer the water) can provide energy for electricity generation. The author extensively reviews the literature to find the best working fluid, with ammonia (R-717) having the highest electrical performance. Ultimately, this means that ammonia is a suitable energy carrier with ample potential to be explored in future research.

Lastly, Azzarone and Monti [78] presented hybridization examples of renewable resources complementary to oil and gas upstream assets. Some crucial examples are photovoltaic (PV) modules-based energy supply to electrical submersible pumps (ESPs), concentrated solar power (CSP) for steam generation for EOR application, and offshore oil and gas platforms wind farms. As we can see, the prospects for joint energy generation and hybrid projects that decarbonize the oil and gas sector are promising, which boosts the likelihood of a successful energy transition process. To that end, techno-economic studies must focus on specific sectors to gain an in-depth understanding. A recent study by Hong (2022) provides a techno-economic analysis of carbon capture, utilization, and storage or CCUS in various sectors [79].

Overall, we considered a set of technologies that rely on green processes to reduce or reutilize the carbon dioxide produced by energy generation processes. Table 1 summarizes the main methods explored in this work and the mechanisms that allow for a significant carbon footprint reduction. Understanding the main contribution of these technologies to a cleaner environment can help expand their reach to be used across industries.

Table 1 Summary of technologies explored and their mechanisms contributing to a CO_2 footprint reduction.

Technology	Factors Contributing to CO_2 Footprint Reduction
Solar thermal applications for EOR	• Steam generation from renewable sources instead of fossil fuels. Promising in hot climates with deficient natural gas availability. • More hydrocarbon recovery from already explored sites, slowing exploration, and excessive drilling of new sites.
Thermal energy generation from/after hydrocarbon production processes	• Creation of energy from fluid flow dynamics in conventional oil and gas recovery processes replaces energy obtained from fossil fuel combustion. • Once depleted, reservoirs can become heat extraction sites, replacing energy produced from fossil fuels.
On-site hydrogen generation	• Gas flaring converts residual gases into hydrogen through pyrolysis, lowering residual elements from fossil fuel combustion and reducing the industry's carbon footprint. • Bitumen gasification separates remaining hydrocarbons inside wells, producing clean hydrogen while sequestering CO_2 in place.
Geological sequestration and CO_2 injection	• Performed emission mitigation and EOR. Emission mitigation implies less carbon released into the atmosphere, whereas in EOR, enhanced recovery and sequestration become feasible. • Huff-and-puff strategies that seek improved recovery restart production of a site after injecting CO_2 that gets sequestered.

7. Summary

Global warming has severely affected the climate, the environment, and society; these effects have been felt more in recent years. The production and use of hydrocarbons and the associated carbon emissions are significant contributors to global warming. For this reason, the oil and gas industry, governments, and international organizations have been seeking ways to minimize dependency on hydrocarbons and enhance methods to generate green energy alternatives. This study presented recently developed and implemented strategies for greener energy to fight against the threat of a changing climate. The procedures and key points discussed throughout the context can be summarized as follows:

- Thermal solar-based steam generation is an innovative method of eliminating the combustion of natural gas through steam generation in thermal-enhanced oil recovery (EOR) processes. Steam generation has been an environmentally friendly method to complement EOR applications. Several operating companies installed the first commercial solar EOR projects in California. The main challenges associated with solar thermal EOR are intermittent energy flows, with the Sun only being available to supply energy during part of the day and related economic and practical limitations.
- Heat extraction by fluid circulation in depleted oil or gas wells is a popular retrofitting method from the viewpoints of the environment and the economy. This class of geothermal projects benefits from the favorable geothermal gradient of wells, only adding retrofitting expenses. Although attractive in concept, only meticulous feasibility studies can reveal its technical and economic applicability and investment worthiness, so the technology is in development.
- In-situ hydrogen generation by gasification of bitumen reservoirs is a recent concept for clean energy production. It involves a water-gas shift reaction to produce energy from depleted heavy oil reservoirs by converting the remaining hydrocarbon from a well into hydrogen fuel cells. The gasification of bitumen enables easy sequestration of CO_2 and allows simultaneous energy production with carbon sequestration. A few examples of this process in Alberta, Canada, a location with rich bitumen reserves, have shown the promise of this method.
- Geological sequestration of CO_2 is a highly effective method to mitigate carbon emissions. The captured and stored CO_2 can also aid EOR from shale reservoirs. Overall, CO_2 injection into oil reservoirs reduces the oil viscosity and increases the reservoir pressure, leading to production enhancement. In contrast, the storage of CO_2 is still particularly challenging, requiring extensive experimental and simulation studies and large-scale field assessments to find its economic viability. From an economic viewpoint, in most cases, CO_2 storage gets integrated into ongoing EOR and EGR projects for better efficiency.

The energy transition is the current trend that NOCs, private sectors, and countries are trying to diversify their energy sources by assessing various economic and environmental considerations. Renewable energy sources, like wind, solar, hydrothermal, and geothermal, have evolved to complement hydrocarbons. Because of this, we have seen the development of methods to utilize renewable energy sources more efficiently in the last few decades, giving rise to the increased contribution of renewables to a nation's energy needs. Incentives are in place to increase the share of green energy worldwide, and governments and major oil and gas industry operators are making due investments.

Author Contributions

All authors contributed to the manuscript as section writers. Cenk Temizel, F. Bahar Hosgor and Hakki Aydin wrote Sections 2, 3 and 4, respectively. Cengiz Yegin wrote the introductory section and partially contributed to the summary. Shah Kabir wrote Sections 5 and 6. Cengiz Yegin led the organization and formatting of the manuscript .

Competing Interests

The authors have declared that no competing interests exist.

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