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Conversion of Abandoned Hydrocarbon Structures into Geothermal Wells for Sustainable Energy Production in Sedimentary Basins

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Abstract

Geothermal energy has gained increasing attention in recent years as a sustainable and renewable energy source that can be utilized for electricity generation, heating and cooling spaces, and various industrial uses. This heightened interest is due to its numerous advantages, including minimal environmental impact, consistent power output, low greenhouse gas emissions, and global availability. These factors collectively position geothermal energy as a significant contributor to global energy production in an eco-friendly manner. However, a significant challenge in geothermal exploration is the high initial investment required for drilling geothermal wells. To address this challenge, novel approaches involve repurposing abandoned petroleum wells for geothermal extraction employing open and closed-loop systems.

These repurposing approaches could generate income, reduce emissions, and preserve infrastructures. These strategies avoid the high costs and uncertainties of drilling new deep geothermal wells, which have historically presented challenges. Abandoned hydrocarbon wells often have suitable geothermal conditions, making energy repurposing an attractive option. It's crucial that repurposing aligns with local energy needs, existing infrastructure, and technological feasibility and knowledge.

Geological context and well's temperature profiles are key factors in estimating their potential in terms of heat transfer and energy production. The thesis conducts a comprehensive literature review to explore existing geothermal closed-loop applications of energy extraction from abandoned petroleum wells worldwide. Additionally, it presents case studies that underscore the significance of working fluid properties, well and pipe geometrical characteristics, and significant parameters in optimizing geothermal energy production.

Table of contents

1. Introduction

As the world's energy demand continues to rise, governments are shifting their focus away from traditional energy sources towards newer, more environmentally friendly options. Geothermal energy, a prominent renewable resource, is gaining attention in this global transition.

Mature oil fields gradually produce large amounts of water alongside oil. As these fields age, managing water resources becomes more expensive, while the revenue from oil decreases. This water typically has temperatures ranging from 65 to 150°C [1]. Combining this warmth with the abundant water volume could offer opportunities for generating electricity or providing heat to nearby areas. Tapping into the geothermal energy within these oil fields could extend their usefulness and offer a sustainable energy source.

Considering the above, this thesis centers on innovative ideas-transforming abandoned hydrocarbon wells into productive geothermal energy sources. Drilling new geothermal wells requires significant financial investment. In this case, repurposing existing abandoned oil wells into geothermal wells represents an innovative and resourceful approach in order to meet our energy needs. This concept comes from a combination of factors, such as, the diminishing profitability of petroleum wells, the need for sustainable energy sources, and the recognition of the necessity for novel solutions to balance economic viability and environmental responsibility.

The exploration and analysis begin from a systematic overview, starting with general energy trends and the role of geothermal energy within the spectrum of renewable resources. We delve into the intricacies of geothermal energy, providing insights into its applications for both generating electricity and providing heating (geothermal energy - direct use), while also examining the classification of geothermal resources. This sets the stage for a more in-depth exploration of the synergy between geothermal and oil fields.
In the subsequent chapters, we narrow our focus to the core of our thesis — the conversion of abandoned or disused oil wells into geothermal energy reservoirs. We investigate the methods and technologies applied for extracting geothermal energy from these geological contexts, with a particular emphasis on the closed-loop system. Within this context, we clarify the variables that significantly affect the performance of coaxial wellbore heat exchangers (WBHE), including the properties of the working fluid, the injection temperature, the well's external geometry, the insulation material of inner tube.

Performing a comprehensive analysis conducted in distinct cases, we derive valuable insights. Notably, we find that the heat capacity of the working fluid plays a pivotal role in shaping temperature profiles and energy production. Moreover, we underscore the critical role of insulation materials, with thermal conductivity emerging as a paramount property in minimizing cooling during upward flow. Maintaining a low injection temperature, relative to subsurface conditions, is revealed as an essential factor that enhances overall extraction efficiency.

2. Global energy transition

The shift towards achieving net-zero carbon emissions involves a multifaceted process where the gradual phasing out of fossil fuels is coupled with the adoption of sustainable and renewable energy sources, alongside efforts to enhance energy efficiency. To address the environmental concerns associated with fossil fuel power plants, a substantial number of them, averaging annually 62 GW of electricity generation capacity, were decommissioned during 2021 and 2022 according to International Renewable Energy Agency (IRENA) 2023 report [1]. To replace decommissioned plants effectively, a significant increase in renewable energy capacity is required. While sources like variable hydropower, solar, and wind energy are valuable contributors, they are not yet capable of completely substituting these decommisioned fossil fuel facilities. Geothermal energy stands out as a valuable component in the global energy transition due to its steady and high plant capacity factor.

Since 2015, renewable energy sources have been the primary drivers of global growth in new electricity generation capacity. In 2022, the capacity of renewable energy sources expanded by 257 gigawatts (GWe), reaching a total installed capacity of 3,064 GWe. This represented a 9% increase compared to the previous year, according to IRENA report in 2022 [2]. Renewables accounted for approximately 80% of all newly installed electricity generation capacity in 2022, with nearly 90% of that coming from solar and wind power. While geothermal electricity witnessed a modest growth rate of approximately 3% between 2000 and 2020, it is expected to accelerate as the new technologies mature and gain wider adoption.

In terms of the composition of renewable energy sources, hydropower remains the largest, contributing to 40.1% of the total installed renewable electricity capacity. Solar energy follows closely behind at 27.7%, with wind power at 26.9%. Bioenergy accounts for 4.7% of the capacity, while geothermal represents 0.5%, and marine energy contributes just 0.02% (Table 1).

Type of power	Installed capacity (GW_e)	Share of total installed renewable electricity capacity (%)
Hydropower	1 230.0	40.1
Solar energy	849.5	27.7
Wind energy	824.9	26.9
Bioenergy	143.4	4.7
Geothermal energy	16.0	0.5
Marine energy	0.5	0.02

Table 1. Total installed renewable electricity capacity [1]

Approximately half of the world's energy consumption is attributed to heating and cooling, with a significant portion of this energy sources from the combustion of fossil fuels. This heating and cooling sector contributes to approximately 40% of greenhouse gas emissions within the energy industry. In 2022, renewable energy sources accounted for a mere 40.4% of the total global energy used for heating and cooling, with geothermal heat contributing just 0.3%, as it is shown in the figure below (Figure 1).

Given the adverse environmental impact of fossil fuel-based heating and cooling, it is expected that solar, thermal, bioenergy, and geothermal technologies will gradually play a larger role in providing heat for various applications [1][3].

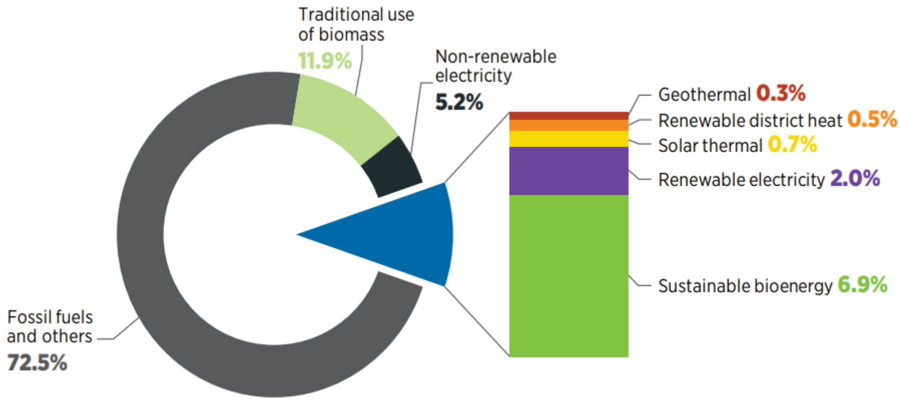

Figure 1. The distribution of energy sources used for heating and cooling in the final energy consumption [3]

Distinctive geographical features, varying geological conditions, differences in electricity markets, national policies, and facilitative frameworks have influenced diverse trajectories in the utilization and development of renewable energy resources across different regions.

Oceania

In the renewable energy world, Oceania has emerged as a frontrunner, witnessing a substantial increase in the share of renewables. Over the decade from 2013 to 2022, the region experienced a remarkable surge, with renewables rising from 21% with 24,051 MW to an impressive 40% with 54,620 MW [2]. Australia played a pivotal role, contributing to a 13% growth in total renewable energy generation from 40,410 MW to 45,516 MW in 2022 alone. This surge can be largely attributed to the escalating adoption of solar PV (photovoltaics) with 17% increase from 22,867MW to 26,789MW, and wind energy, which saw a remarkable rise from 8% of total renewable energy with 8,950 MW to 22% with 10,134 MW during the same period [4]. The other main contributor to the total renewable energy share of the region is New Zealand with 8,066 MW in 2022 [2]. Shares of the remaining countries of the region are nearly negligible compared to the main contributors.

On the other hand, the share of geothermal energy in the Oceania region increased by 18% during the period from 2013 to 2022, comprising only 2% of the total renewable energy, with the only contributor of the region being New Zealand with the current 1273 MW [2]. In New Zealand, geothermal energy satisfies 22% of the national electricity demand. Although substantial resources have been identified, and various companies are in advanced stages of exploration, there is currently no operational commercial production of geothermal energy in Australia.

Asia

The total renewable energy capacity in the Asia region, as reported by IRENA - Renewable Capacity Statistics [2], reached 1,630,282 MW in 2022. The predominant contributors to the region's renewable energy landscape include hydropower, wind and solar energy. Notably, hydropower leads with a capacity of 619,681 MW, followed closely by solar energy at 597,573 MW, and wind energy at 425,674 MW. However, despite our focus on geothermal energy, it occupies a comparatively very smaller share, standing at only 4,711 MW in 2022.

Shifting our focus to China, the powerhouse of renewable energy, the nation achieved a historic milestone in 2021 by surpassing 1 terawatt (TW) of installed renewable energy capacity.

China's dominance was evident as it accounted for a staggering 43% of the total global additions in 2021. Solar power played a significant role with 306,973MW, representing 31% of global solar PV additions with 53,009MW in 2021 [2]. Moreover, China took the lead in bio-power, hydropower with 413,500MW, solar PV with 392,436MW, and wind power with 365,964MW, showcasing its comprehensive influence across diverse renewable energy sectors [2][5].

However, in the global landscape of renewable energy, geothermal power faced a setback in 2022, with capacity additions dropping by one-third compared to 2021, totaling only 0.2 GW which is much less compared to other main renewable energy source additions [4]. Despite this decline, the Asia-Pacific region is home to seven countries operating geothermal plants, contributing to 37% of the world's installed geothermal electricity capacity with total 4,711MW [2]. Notably, three countries from the region, China, Indonesia and Philippines rank among the top 10 geothermal electricity-producing countries globally.

China, with an installed capacity of 40.6 GWth, stands out as a global leader in ground-source heat pumps and geothermal district heating, accounting for 38% of geothermal heating and cooling utilization worldwide [1]. Despite being one of the leading countries in geothermal energy capacity, China's utilization of its full geothermal potential remains suboptimal, especially given its expansive territory and abundant geothermal resources.

The considerable number of abandoned oil wells, exceeding 76,881 as of 2016 [6], further emphasizes the untapped potential. It becomes evident that China has room for significant improvement in harnessing geothermal energy. The conversion of these abandoned oil wells into geothermal wells represents a strategic opportunity, offering a pathway to enhance and expand China's geothermal energy sector.

India possesses significant geothermal potential, estimated at 10 GW [7]. However, the country's primary renewable energy sources currently include solar PV with 62,804 MW, hydropower with 52,002 MW, and wind power with 41,930 MW. Despite its vast geothermal potential, the contribution of geothermal energy to the overall renewable energy share in the country remains at zero. According to a 2020 report from the Ministry of Petroleum and Natural Gas [8], the total number of oil wells since the minitry's inception is 20,562, with 13,348 of them abandoned. These abandoned wells represent a valuable opportunity for geothermal energy extraction, presenting a practical avenue for India to diversify its renewable energy portfolio and tap into its untapped geothermal reserves.

Indonesia emerges as a geothermal energy hotspot, boasting the world's largest estimated potential of 29,000 MW according to the Asian Development Bank. The nation has set an ambitious target to achieve a geothermal production capacity of 5000 MW by 2025. In this endeavor, both hydropower and geothermal power are expected to contribute 25% to the country's power supply [9]. As many of Indonesia's oil and gas resources near the end of their financially feasible operating lifespan, over 100 unused platforms and over 20,000 inactive wells, both onshore and offshore, await decommissioning and abandonment [10]. Leveraging these inactive wells presents a significant opportunity for Indonesia to play a crucial role in fulfilling its government's plan for sustainable and diversified energy sources.

North America

North America stands out as a renewable energy powerhouse, bestowed with some of the world's most abundant wind, solar, geothermal, hydro, and biomass resources. According to the International Renewable Energy Agency [2], the total Renewable Energy Capacity in the North American region reached 489,226 MW in 2022, marking a substantial increase from 272,514 MW in 2013, nearly doubling its previous share. The primary contributors to the region's renewable energy portfolio are hydropower and wind energy, along with solar energy, boasting capacities of 200,085 MW, 163,469 MW, and 126,443 MW, respectively, in 2022.

Conversely, despite the region's rich geothermal potential, its contribution to the overall renewable energy share is relatively low, standing at 3,712 MW in 2022 with marginal growth [2]. The primary geothermal energy reserves are nestled between Mexico and the USA. Despite their substantial geothermal potential, both countries underutilize this renewable energy source in comparison to other alternatives. However, IRENA analysis shows that Mexico could reach 4.5GWe of capacity by 2030. In the United States, geothermal energy comprises only 0.4% of the national electricity output in 2022 [1]. Notably, both nations are home to a vast number of abandoned oil wells, estimated at 3.5 million orphaned and abandoned wells in US according to government data [11].

The conversion of these abandoned oil wells into geothermal wells presents a transformative opportunity. This shift could significantly contribute to the growth of geothermal energy, which has seen a comparatively modest growth rate of 1.4% annually over the past 30 years, falling short of the global average of 3.6% during the same period. Despite this, the United States holds a substantial 23% share of the world's geothermal electricity capacity, amounting to 2.7 GWe [1].

Central America and Caribbean

The total renewable energy capacity of the region stands at 18,052 MW in 2022, with the primary contributors being hydropower at 8,265 MW, followed by solar and wind at 3,987 MW and 2,036 MW, respectively. Despite the region’s geothermal energy capacity reaching 724 MW, which is relatively close to other renewable energy types, especially when compared to South America, it still remains relatively low [2].

Turning our focus to geothermal energy, the Central American and Caribbean region has deployed approximately 0.7 GWe of capacity, representing 5 % of the global installed capacity of about 15 GWe. Geothermal electric plants operate in 17 fields spread across 8 countries, primarily concentrated in Central America [1].

Central America has emerged as a notable player in geothermal electricity generation, surpassing South America and the Caribbean in capacity development. In some Central American countries with smaller electricity markets, a few hundred megawatts of geothermal installed capacity make up a substantial portion of national electricity demand. For instance, El Salvador relies on geothermal for 24.9% of its electricity only with 204MW, Nicaragua for 20.8% with 153MW, and Costa Rica for 14.6% with 263MW [1][2].

South America

In 2022, the total renewable energy capacity in the South America region reached 264,719 MW, with Brazil playing a crucial role by contributing a significant 66% to the total. Other notable contributors include Chile with 17,910 MW, Venezuela with 16,906 MW, Argentina with 15,076 MW, and Colombia with 13,435 MW. Hydropower is the predominant renewable energy source in S. America, accounting for 179,934 MW. Wind power and solar power follow closely, with approximately equal shares of 33,471 MW and 32,773 MW, respectively [2].

Brazil leads in various categories of renewable energy sources, contributing 61% of hydropower, 72% of wind power, and 73% of solar energy in the region. Despite this impressive performance, Brazil currently lacks a share in geothermal energy. The sole geothermal energy capacity in the region belongs to Chile, but even with its substantial geothermal potential, Chile utilizes only 51MW of geothermal energy [2].

In 2022, Brazil had 7,267 wells, a decrease from over 9,000 wells in 2014, with more than 91% located onshore [12]. As explored later in this thesis, repurposing these abandoned wells for extractions of low-temperature geothermal energy resources for industrial use and space heating could be beneficial for enhancing the region's sustainable energy portfolio.

Africa and Middle East

In Africa, there has been a commendable increase in the share of renewable electricity, witnessing a rise from 17% in 2012 to 24% in 2022 - an impressive 7% increase. Noteworthy growth in hydropower is observed, with its share rising from 16% to 19%. Solar and wind energy also made substantial strides, collectively growing from 0.4% to 4.7%, with wind contributing 2.7% and solar 2%. This upward trajectory continued in 2022, as renewable electricity in Africa experienced an 11% growth, surpassing the 5% increase observed in 2021 [11].

The region has become a significant player in the global geothermal landscape as well. With an installed capacity of 978 MWe, it constitutes about 6.5% of the global total of 15 GWe. Kenya, particularly the Olkaria geothermal field, stands out as a major contributor, hosting six electricity plants generating 967 MWe, including wellhead units with a total capacity of 81 MWe. Additional geothermal power plants are found in the Eburru geothermal field in Kenya (2.52 MWe) and the Aluto Langano geothermal field in Ethiopia (8.5 MWe) [1].

Kenya, indeed, holds a prominent position among the top ten geothermal electricity-producing countries globally. In 2019, geothermal accounted for a substantial 29% of the national electricity installed capacity and an even more impressive 47% of the electricity consumed. The Kenyan geothermal market has showcased remarkable growth, sustaining an annual growth rate of 6-13% per year over the last decade - significantly surpassing the worldwide average of 2-4.6% per year. This underlines Kenya's role as a leader in the global geothermal energy landscape [1].

As of IRENA's 2023 statistics [2], the total renewable energy capacity in the region amounts to 28,539MW, primarily divided between two key renewable sources: hydropower, with a total capacity of 14,502 MW, and solar energy, contributing 12,882 MW. Four main countries collectively share this renewable energy capacity, with Iran IR leading at 12,045 MW, followed by Israel with 4,470 MW, the United Arab Emirates with 3,058 MW, and Jordan with 2,555 MW.

Each of these countries predominantly relies on a single renewable energy source within their portfolio. Iran's primary focus is on hydropower, constituting 11,153 MW of its total capacity.

In contrast, Israel, the UAE, and Jordan prioritize solar energy, with respective capacities of 4,411 MW, 3,040 MW, and 1,914 MW.

On the other hand, despite the Middle East's vast potential and likely abundance of abandoned oil wells, given its prominence in global petroleum production for a long time, the region has not embraced geothermal energy as a significant renewable energy source on a large scale. This discrepancy highlights an untapped opportunity for the Middle East to diversify its energy portfolio and leverage its geothermal potential for sustainable and cleaner energy alternatives. Repurposing abandoned oil wells for geothermal energy extraction could prove to be a strategic move in aligning the region with global efforts toward more sustainable and environmentally friendly energy solutions.

Europe

In Europe, the renewable energy landscape has undergone a transformative shift over the past decade. Wind power has surged, representing 11% of the region's total generation in 2022, a substantial increase from 4% in 2012. Similarly, solar power has experienced significant growth, comprising 5% of the total generation, up from 1.5% in 2012. Despite opposing trends across technologies, the overall renewable electricity generation in the region remained stable. Hydropower, heavily impacted by droughts and water scarcity, witnessed an 11.5% decline compared to 2021. In contrast, solar PV saw a record growth of 21.6%, and wind power generation increased by 11.2% [2][11].

The geothermal landscape stands out with an installed capacity of approximately 3.54 GWe for electricity, constituting about 22% of the global geothermal electricity installed capacity of 15 GWe. Several countries are users of geothermal energy on large scale. Italy has been a significant contributor, installing 916 MWe in 2020, which increased to 944 MWe in 2021 from over 30 geothermal electric plants. Iceland, situated in a volcanically active zone as a geological context, harnesses significant geothermal potential, boasting a total installed capacity of 754 MW. Türkiye has witnessed a remarkable proliferation in the geothermal sector over the last decade, increasing from 30 MWe in 2008 to an impressive 1,676 MWe in 2022 [1].

Over the last 20 years, global geothermal electricity capacity has seen an average annual growth rate of 3.2%. Interestingly, Europe has outpaced the global average, experiencing a faster growth rate of 5.2% per year [1]. This highlights the region's commitment and success in harnessing geothermal energy as a sustainable and growing component of its electricity generation portfolio.

However, while Europe stands at the forefront of geothermal utilization, there are several countries, including France, Hungary, Romania, Poland, and others, that possess numerous abandoned oil wells that could potentially be repurposed for geothermal use.
Around 12,500 wells have been drilled in France since the 19th century for the exploration and extraction of hydrocarbon reservoirs. The majority of these wells are either abandoned or are reaching the end of their production life, aligning with France's scheduled cessation of hydrocarbon exploitation by the year 2040 [13]. These abandoned oil wells can contribute the increase of the geothermal energy capacity of France which was only 16 MW in 2022 according to IRENA statistics report [2].

3. Geothermal energy and its potential as a renewable energy source

Introduction to geothermal energy

Sustainable development is nowadays confronted with three primary challenges: a rapidly expanding global population, an energy deficit, and escalating environmental degradation. To address these issues, several countries are investing in research on new and renewable energy sources in order to reduce their dependency on existing fossil fuels [14]. Renewable energy production is predicted to triple between 2010 and 2035, accounting for 31% of total generation [15].

Geothermal energy refers to the stored heat energy in the earth's crust. Technically, geothermal energy is available everywhere around the world because of the source of this energy. As seen in Figure 2, thermal energy runs from the Earth's core to the surface, resulting in geothermal gradients.

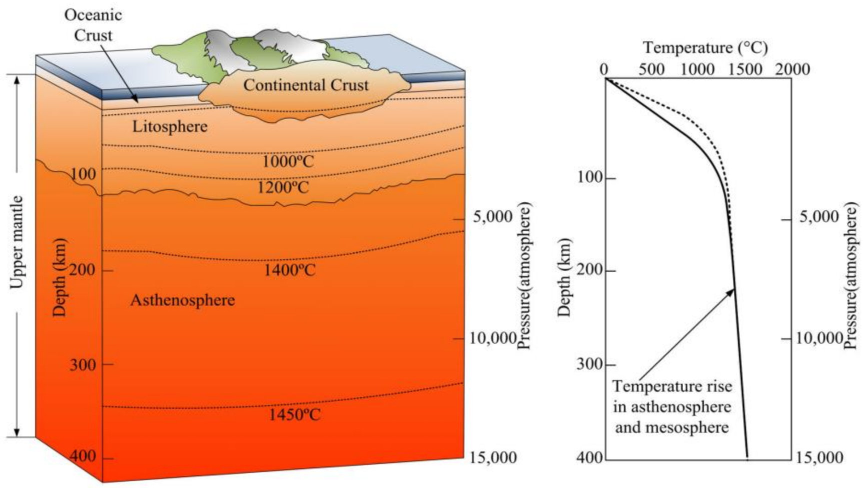

Figure 2. Schematic Depiction of Earth's Layer Structure and Temperature Distribution [14]

The amount of energy stored within the planet is considered limitless when compared to other energy sources [14].

Presently, around 82 countries and regions utilize geothermal energy for direct applications, while over 30 countries and regions use it for electricity production, with installed capacities ranging from less than 1 MWe to 3.7 GWe. The primary technologies employed for generating electricity from geothermal sources include **dry steam**, **flash steam**, and **binary power plants**. Certain countries like Indonesia, New Zealand, the Philippines, Türkiye, and the United States have been operating geothermal power plants for several decades. In contrast, countries such as Belgium, Chile, Colombia, Croatia, Honduras, and Hungary have only recently initiated geothermal electricity generation and are in earlier stages of development.

As of the end of 2022, the global installed capacity for geothermal electricity generation reached 15.96 GWe, distributed across five major regions (Figure 3). The regions with the largest installed capacity are Asia and Oceania (5.9 GWe), North America (3.7 GWe), and Eurasia (3.5 GWe) [1].

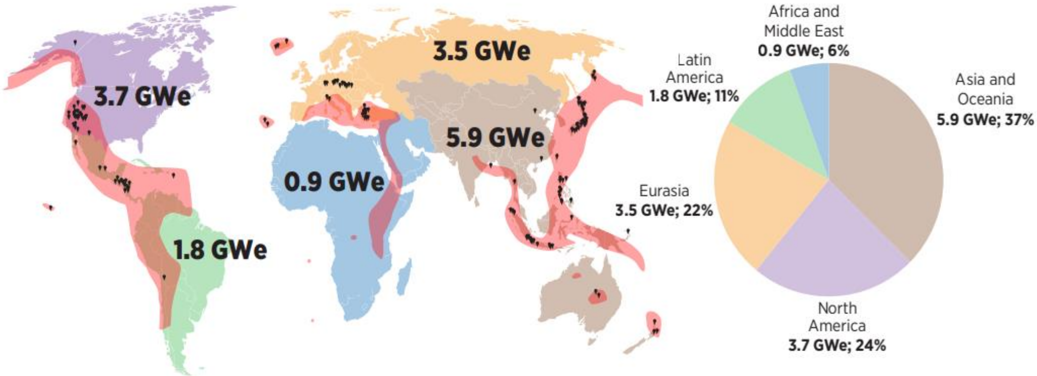

Figure 3. Installed geothermal electricity capacity [1]

The utilization of geothermal energy for electricity generation varies across regions and countries and is not solely dependent on the availability of suitable geothermal resources. Even in regions with favorable volcanic conditions like the Pacific Ring of Fire, the level of geothermal development differs significantly among countries. For example, North America and Central America have more established geothermal industries compared to South America and the Caribbean Islands. Recent advancements in geothermal electricity have been made by tapping into lower-temperature resources, not necessarily associated with volcanically active regions, as seen in Türkiye and certain European countries [16].

The global electricity generation capacity from geothermal plants has grown from 200 MWe in the early 1950s to approximately 16 GWe by 2022. Key contributors to this growth include Indonesia, Kenya, Turkey, and the United States. Despite this growth, geothermal energy only represented 0.5% of the global renewable electricity market in 2022 (Table 1) [1].

The global energy market's current context resembles past energy crises, offering new opportunities for geothermal electricity to further develop as a strategic alternative capable of enhancing electricity generation systems in many countries. In 2022, the total installed capacity for geothermal heating and cooling worldwide reached 107.4 GWth. Of this capacity, 72% was attributed to geothermal heat pumps, while the remaining 28% came from direct heating and cooling using geothermal fluids. These geothermal heating and cooling applications are predominantly concentrated in three regions: the Asia and Oceania region led globally with an installed capacity of 45.8 GWth, accounting for a 43% share, Eurasia followed closely with 38% of the capacity, North America accounted for 21% of the total capacity. On the other hand, Latin America, the Caribbean, Africa, and the Middle East each contributed 1% or less to the global geothermal heating and cooling capacity [2].

Geothermal energy is utilized for heating and cooling purposes in more than 80 countries worldwide. Among these, ten countries boast substantial installed capacity, with at least 2 GWth, which includes the use of Ground Source Heat Pumps (GSHPs). China leads the pack with the highest installed capacity of 40.6 GWth, followed by the United States with 20.7 GWth, Germany with 4.8 GWth, Turkey with 3.5 GWth, France with 2.6 GWth, Japan with 2.5 GWth, Iceland with 2.4 GWth, Finland with 2.3 GWth, and Switzerland with 2.2 GWth [1].

Geothermal energy provides various advantages, including the capacity to deliver consistent and steady power (i.e., base load power), no output fluctuation throughout the year, and

immunity to weather-related causes and the effects of climate change. Moreover, geothermal energy is suitable for both centralized and decentralized energy generation systems [17].
Geothermal energy has enormous growth potential. The heat present within the top 10,000 meters of the Earth's crust is projected to hold an energy potential that is 50,000 times greater than the combined resources of global oil and gas [18]. Furthermore, there is a compelling economic argument for using geothermal energy.

As the technology develops, the cost of electricity generation from geothermal energy getting more competitive. According to the prediction of IEA costs will continue to drop through 2050 [19]. Deploying geothermal energy also assists in reducing global warming impacts and public health hazards associated with the usage of conventional energy sources. Moreover, the reliance on fossil fuels also becomes reduced as a consequence of geothermal energy usage.
Despite its promise, the geothermal sector is confronted with several limitations that have compromised its development. The high upfront capital expenses of establishing geothermal plants are one of the major problems. According to the IEA [20] the cost of drilling and finishing a geothermal well can be up to $10 million, which is a considerable barrier to entry for many.
An additional obstacle involves the limited presence of appropriate geothermal reservoirs in specific areas: geothermal resources are concentrated in certain places, such as the Pacific Ocean's Ring of Fire, and access to these resources can be difficult and costly. This inhibits geothermal energy's ability to become a widely used renewable energy source across the world.

Despite these limitations, the geothermal sector has various potential to grow and flourish. The development of novel geothermal technologies such as enhanced geothermal systems (EGS), supercritical geothermal systems (scoops), hydrocarbon wells' reuse for geothermal energy production is one possibility. These technologies have the potential to uncover previously inaccessible geothermal resources, which will boost the quantity of geothermal energy available globally.

Geothermal energy utilization

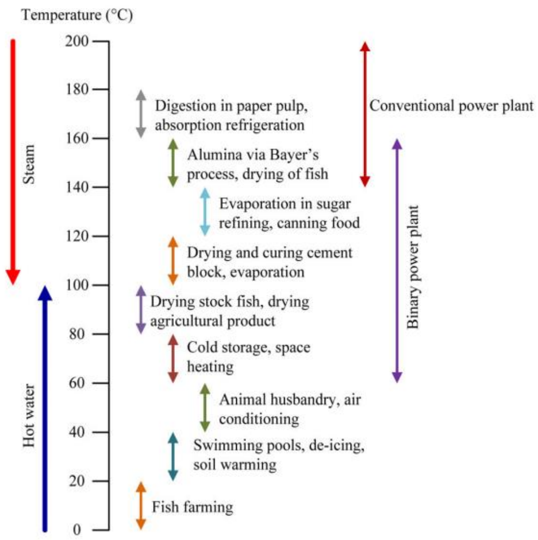

Figure 4. Geothermal energy utilization diagram by Lindal [15]

Depending on the well's temperature, the extracted thermal energy can be used for a variety of implications. Figure 4 depicts Lindal diagram showing various geothermal production utilizations. As it is illustrated above, conventional electricity generation utilizing dry steam or flash steam power plants will be practicable only at temperatures exceeding 150 degrees Celsius. Lower than that, energy generation is only possible with the use of a binary power plant. Besides, geothermal energy has a wide range of uses for direct thermal application. The most basic kind of geothermal usage is for heating, particularly bathing and washing clothing, where it may be utilized directly without additional conversion. Low-temperature sources can be used for fish farming, whilst high-temperature sources may be used for deicing, space heating, soil warming, drying of aquaculture and agricultural products, and sugar processing. Geothermal energy may be used for cooling and refrigeration by employing conversion systems, which considerably expands its potential application. It can then be utilized for cold storage or air conditioning. Geothermal energy has been employed for therapeutic purposes in addition to technological uses.

Geothermal resources classification

A geothermal system refers to a specific geological environment where a circulating fluid enables the extraction and transfer of thermal energy from the Earth to a designated location for utilization. This system includes vital components and mechanisms, including fluid and heat sources, fluid flow paths, and a caprock or seal, all of which are important in the creation of a geothermal resource.

Geothermal systems involve heat transfer, a process in which the internal energy of one body decreases while the internal energy of another increases. This transfer occurs through various mechanisms such as heat conduction, convection, radiation, and phase transitions. Essentially, heat is moved from one environment to another across a separating wall. In this context, a heat source transfers its energy to the wall's surface, and, facilitated by thermal conductivity, the wall then releases this heat to a colder heat carrier.

The efficiency of conductive heat transfer in notably influenced by the thermal conductivity of rocks. Moreover, convective heat transfer, a process occurring between heated components of a liquid or between a liquid and solids, is integral to understanding the dynamics of heat transfer in geothermal systems.

The classification of resources is a critical component in the assessment, characterization, and development of geothermal energy. To effectively assess geothermal resources, it is critical to construct a coherent and consistent categorization system based on the above-mentioned stated components and methods [21].

The factor considered for classification involves the extent of **natural convection** within a specific geothermal system. This is influenced by the permeability structure of the system and the heat input at its bottom. At a given pressure gradient, the mass flow rate of fluid per unit area is determined by the permeability of reservoir rocks and the dynamic viscosity of the reservoir fluid (Darcy's law). Flow rate is directly proportional to permeability, measured in units of 10^{-15} m^2 = 1 millidarcy (mD) = 1 mD. To describe reservoir characteristics, average permeabilities related to liquid flow are categorized as "very low" for permeabilities < 1 mD, "low" for 1-10 mD, "intermediate" for 10-100 mD, and "high" for 100-1000 mD. Geothermal reservoir permeability not only varies from layer to layer but also exhibits anisotropic permeability, meaning it varies with direction [22].

Temperature is also an important indication of the type of geothermal energy resource and is used to detect and harness it. As a result, because temperature is an important factor in analyzing and categorizing geothermal resources, it is the basic basis for most categorization systems. The temperature of geothermal resources may be divided into three categories: low, middle, and high-temperature resources. The classification reflects the suitability of the different resources for various applications, such as space heating and cooling, industrial drying, power generation, and other uses. While other classification methods exist, this temperature-based classification is one of the most common ways to categorize geothermal resources.

High-temperature geothermal resources: this form of geothermal energy resources can be found near active volcanic and tectonic zones, where temperatures can exceed 150°C. High-temperature geothermal energy resources are dominated by liquid and vapor. These resources are used for electricity generation, as they can produce steam to power turbines.

Medium-temperature geothermal resources: this form of geothermal energy resources is found in shallower locations with temperatures ranging from 90°C to 150°C. Medium-temperature geothermal resources are nearly entirely liquid-dominated and are mostly utilized for direct heating applications such as district heating systems, industrial processes, and greenhouse.

Low-temperature geothermal resource: low-temperature geothermal energy is found in places with temperatures ranging from 30°C to 90°C. Low-temperature geothermal resources are entirely liquid-dominated, and they are mostly utilized for heating and cooling systems, such as heat pumps in residential and commercial buildings [23].

The geological context influences the reservoirs' features and geothermal gradients' values, thus limiting the type of geothermal resources available.

As reported above, the majority of high-temperature geothermal resources are located in tectonically and volcanically active locations, such as the Pacific Ring of Fire, the mid-Atlantic ridge, sections of Europe, and the East African Rift. These resources can be discovered at depths ranging from a few hundred meters to several kilometers depending on the local subsurface temperature gradient.

Low and medium-temperature resources are more regionally spread, with considerable resources along faults and fractures in tectonically active locations as well as deep in sedimentary basins. The coexistence of hydrocarbons with low- to medium-temperature geothermal energy resources has been confirmed by available geological and geophysical exploration data into the deepest parts of such environments. Because sedimentary basins often have lower temperature gradients than volcanic regions, deeper drilling (to several kilometers) is frequently required to reach adequate reservoir temperature [1]. In mature Italian oilfields in sedimentary basins, deep wells can represent suitable candidate structures for geothermal heat exploitation, thus providing access to subsurface energy resources.

Geothermal energy resources may also be categorized into two types based on **accessibility** and **reservoir characteristics**: conventional and unconventional

Conventional geothermal resources: the Word “conventional” refers to geothermal systems that can be exploited using traditional drilling and well technologies. Conventional geothermal resources are often found in areas characterized by volcanic or tectonic activity. The existence of permeable rock formations and high-temperature fluids or steam near the Earth’s surface distinguishes these resources. They are thought to be more easily accessible and economically viable for producing geothermal energy. Conventional geothermal systems often have well-defined reservoirs where the hot fluid or steam can be directly tapped for electricity generation or direct-use applications.

Unconventional geothermal resources: they refer to those resources that require additional technological advancements or modifications to be effectively utilized. These resources are often found in areas with lower temperatures or deeper reservoirs.

4. Hydrocarbon structure decommissioning

Onshore hydrocarbon wells decommissioning

Despite its tremendous potential, the progress in the utilization and adoption of geothermal energy systems has been relatively slow and focused only on specific geographical locations, that is, areas with intense volcanic and hydrothermal activities. The main reason for this slow progress is the challenging, high-risk and high cost of geothermal wells drilling process.

On the other hand, sedimentary basins also serve as significant geological contexts for hosting substantial geothermal energy resources. Simultaneously, these basins are directly linked to hydrocarbon wells, creating an interconnection between geothermal resources and deeper hydrocarbon exploration. Therefore, a possible approach to address the issue of high drilling costs is to make use of abandoned oil and gas wells in sedimentary basins. These abandoned wells offer a promising opportunity for transformation into geothermal wells, given their existing infrastructure, elimination of the need for new drilling, and the wealth of comprehensive historical data that allows for accurate performance assessment, reduced risks, and improved cost projections. Moreover, existing facilities available in the oil wells can be directly converted to support geothermal energy extraction, saving a considerable cost as compared to constructing a new geothermal energy drill hole and plant. Conversion of abandoned oil wells into geothermal wells presents the advantage of reducing or entirely avoiding the expenses associated with decommissioning outdated wells. This retrofitting approach also prolongs the economic viability of these wells and reduces the risks related to potential fluid or gas leakage from sealed wells.

It was reported that millions of oil and gas wells have been abandoned around the world, many of which are leaching pollutants into air and water. As the quantity of aged and financially unviable oil and gas wells rises, the possibility of converting them into geothermal wells gains greater prominence [24].

The ultimate stage of the oil well life cycle, which begins with exploration, drilling, production, and eventually abandonment, is decommissioning and/or abandonment. As a result of oil wells drilled tens of years ago, the majority of these wells have reached or are nearing the end of their productive and economic eras. Thousands of onshore and offshore wells must be securely sealed and abandoned across the World. More wells are predicted to be abandoned during a pandemic because of low demand for oil and gas [24]. The decommissioning and abandonment of oil wells is an extremely difficult procedure. This step is frequently more difficult than the original exploration and installation. The main goal of well abandonment is to permanently seal off all rock formations opened by the well [25]. In an ideal condition, the abandonment should prevent reservoir fluid and other liquids from leaking from the rock layers to the surface or moving to neighboring formations. Methane leaks from abandoned oil wells have been documented [26][27].

The decommissioning process typically involves several key stages. One of them is planning and regulatory compliance. A decommissioning strategy should be submitted to the appropriate authorities far in advance of any decommissioning action. It might be as early as 5 years in certain countries, and at least 2 years before decommissioning [28].

This plan should include details of facility design, fabrication, installation, and commissioning, potential risks and hazards due to facility removal, planned method, analysis, and operation during decommissioning, waste control, and a possible monitoring system. In brief, precise and extensive planning is critical to the effective execution of well decommissioning and abandonment. Poor abandonment will not only be difficult to correct but will also be costly and provide a negative reputation to the oil and gas sector.

Before proceeding with the decommissioning and abandonment processes, it is critical to address the usual practice in the oil and gas sector of deploying two well barriers (primary and secondary). As demonstrated in Figure 5, this barrier is significant during exploration, production, and abandonment. This barrier will also be important when the well is converted to a geothermal well. As indicated, the primary barrier during the drilling stage is the drilling fluid, while the secondary barriers comprise the casing, wellhead, and blowout preventer (BOP) [30].

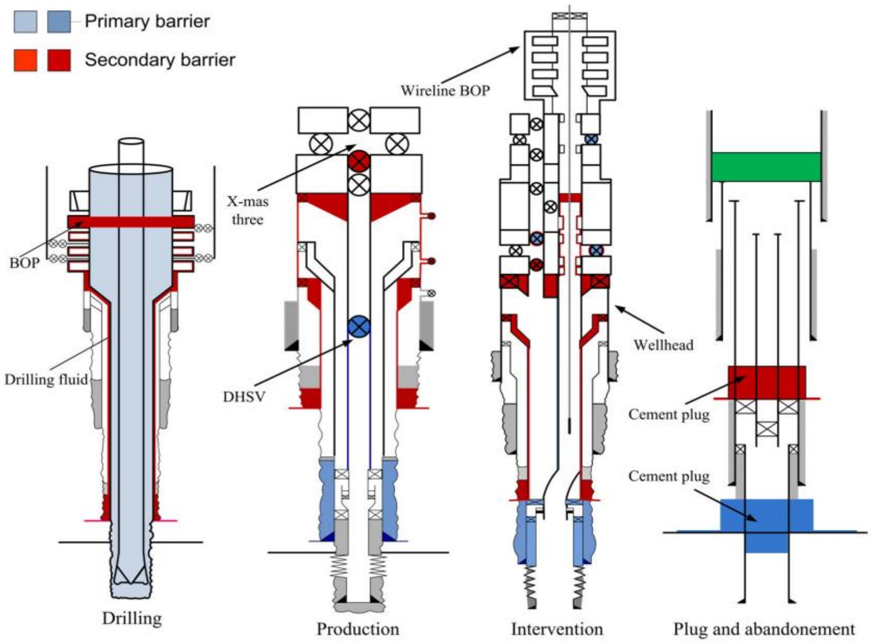

Figure 5. Simplified well barrier illustration [29].

During the producing process, the primary barrier includes casing cement, casing, packer, tubing, and a downhole safety valve (DHSV), while the secondary barrier includes a tubing hanger and a Christmas tree [30].

When a well is interrupted for intervention activity, the primary barrier consists of casing cement, casing, a deep-set plug, and overbalanced mud, while the secondary barrier is identical to those employed during the drilling stage. Cement plugs, in addition to the wall casing, are utilized as primary and secondary barriers at the end of the well's life during abandonment. It is critical to have detailed knowledge of this barrier if the abandoned well is converted into a geothermal well.

In general, whether onshore or offshore, well abandonment is divided into three stages [30]

- reservoir abandonment,
- intermediate abandonment
- removal of the well head and conductor

The first step consists of well inspection and integrity evaluation, waste management system erection, and finally installation of permanent primary and secondary barriers. Milling, casing retrieval, barrier installation to isolate intermediate hydrocarbon or water-bearing permeable zones, and environmental plug placement are all part of the second phase. The last process is carried out to prevent any future accidents or incidents affecting this top structure. Once the particular wellbore has been safely and permanently abandoned, the support facilities and buildings must be decommissioned and removed to restore the site to its pre-oil/gas extraction condition. When this phase is finished, re-entry into the wellbore is nearly difficult.

As a result, converting this permanently sealed well into a geothermal well is unfeasible. In reality, the choice to convert/retrofit an oil-gas well into a geothermal well must be taken before or during the decommissioning plan stage.

Despite the fact that identical phases are involved, each well decommissioning and abandonment is unique and presents various obstacles. The important criteria for decommissioning onshore wells are well depth and downhole pressure. The kind of facility and serviceability, water depth, and downhole pressure should all be considered while drilling an offshore well. These criteria will not only determine the difficulty of the well abandonment procedure but also the expense of completing it [30].

Offshore decommissioning

Oil and gas production platforms, resembling islands, extend throughout the water column from the seafloor to the sea surface. Unlike islands, these structures facilitate water circulation, dissipate oceanic energy, and offer easy mobility for fish. Different species of fish inhabit platforms from the surface to the seafloor.

In terms of decommissioning, platforms typically comprise two distinct parts: the topside and the substructure (components between the sea surface and the seabed or mudline). During decommissioning, the topside facilities containing operational components are completely removed and transported to shore for recycling or partial re-use. The substructure supporting the jacket is typically severed 15 feet below the mudline, extracted from the seafloor, and either sold as scrap for recycling or refurbished for installation elsewhere, possibly ending up in a landfill.

Normally, decommissioning entails the complete removal of the platform, and restoring the seafloor to its prelease condition. However, an alternative option is reefing the submerged sections of the platform structure, known as Rigs-to-Reefs (RtR), which involves converting decommissioned platforms into artificial reefs. This practice has been observed in the U.S., Brunei, and Malaysia, particularly in the Gulf of Mexico, where around 11% of decommissioned platforms have been integrated into state artificial reef programs [31].

Decommissioning always requires the removal of topside facilities, leaving the jacket as a potential reef. A jacket, a steel support structure resting on the ocean floor with columns or legs extending from below the seafloor to the sea surface, is anchored in place by pilling driven into the seafloor.

Three methods exist for converting the subsurface jacket section into an artificial reef. Partial removal, often occurring at 85 feet below the mean waterline, typically relies on non-explosive means to cut the platform, resulting in higher reef profiles and less habitat trauma compared to toppling in place. The latter involves explosive severance to cut piles and lay the jacket on its side.

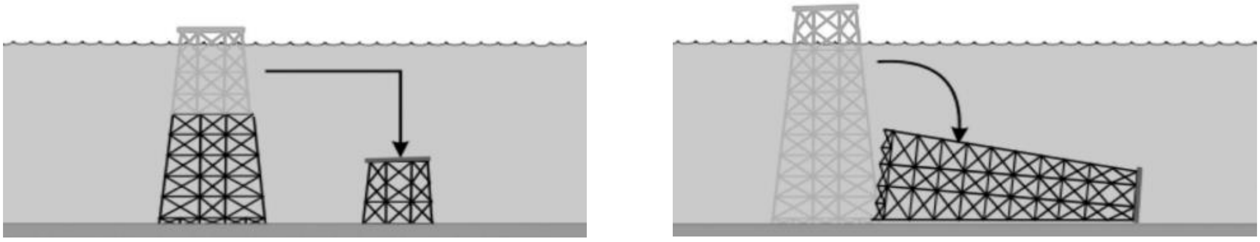

Figure 6. Partial removal platform reefing (on the left) and Topple-in-place platform reefing (on the right)[32]

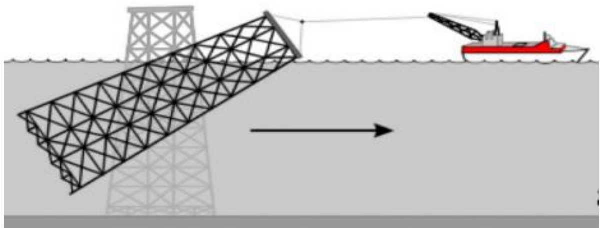

Figure 7. Tow-and-place platform reefing [32]

The tow-and-place platform method involves severing the platform from below the seafloor, often using explosives, and towing it to a designated reefing area [32].

The timing of decommissioning activities depends on various factors, such as the time limit and specifications of the state or federal lease, the geologic type and size of oil and/or gas reservoirs, production rates, transportation logistics, market values, potential resale or reuse, and whether the platform might serve an extended use. Considering all these factors, converting a decommissioned platform into an artificial reef may not always be economically viable for the industry. Factors like structure size (when tow-and-place platform reefing considered), water depth, distance from shore, and the distance to the final reef site further influence this decision.

Reefing case from USA - Artificial Reef Program of Louisiana

Louisiana anticipated the National Artificial Reef Plan (NARP) with bated breath. Louisiana, unlike Alabama or Texas in the mid-1980s, lacked a pre-established artificial reef policy. The Louisiana Fishing Enhancement Act (LFEA) was passed in 1986, paving the path for the Louisiana Artificial Reef Program (LARP). This collaborative initiative involved the Louisiana Department of Wildlife and Fisheries (LDWF), Louisiana State University, the state legislature, the offshore oil and gas industry, and influential fishing organizations.

The offshore and inshore shrimping industry, employing otter trawls, is a cherished domestic tradition and a significantly profitable sector for coastal Louisiana. However, the competition for space arises between trawling the seafloor and the structures of artificial reefs; the presence of one hinders the other.

The enactment of the LFEA transpired during the regular legislative session of 1986. Guided by the LFEA, the Louisiana Artificial Reef Plan was formulated, outlining the steps for implementing the legislation that led to the establishment of LARP in the same year.

In collaboration with various stakeholders, including fishing organizations, LARP delineated nine artificial reef planning areas on the federal Outer Continental Shelf (OCS) for Rigs-to-Reefs (RtR) proposals along its coast. The program has embraced more than 500 decommissioned platforms for repurposing as reefs (table below) [32][33].

Gulf of Mexico Federal Oil and Gas Platforms 1942-2016	
Total number of Platforms installed	7074
Total Number Platforms Removed	4959
Total Number Platform Jackets Reefed	515
Percent Platforms Reefed During Decommissioning	11.19%

Seventeen special artificial reef sites, established under the State's artificial reef plan, exist beyond the planning areas, offering available space for additional oil and gas structures to be repurposed as reefs. LARP has identified offshore waters exceeding 400ft as a deepwater artificial reel planning area. Presently, eight platform structures have been converted into reefs in deepwater. Louisiana recently designated two additional sites, bringing the total to 11 designated artificial reef planning areas. Additionally, ongoing collaboration with the Texas Parks and Wildlife Department (TPWD) is underway to formulate two new artificial reef planning areas off the coast of Corpus Christi.

Approximately 70% (almost 5000) of Gulf petroleum structures were installed in depths less than 100ft. Surprisingly, only 1% of reefed platforms are situated within this depth zone, where much of the offshore bottom trawling activity occurs. Contrastingly, over 80% of decommissioned reefed platforms find their new purpose in water depths exceeding 150ft. In these deeper depths, bottom trawling is limited, and there is a lower density of petroleum infrastructure, leading to fewer conflicts over space usage.

The state receives 50% of the savings from reefing compared to the estimated cost of total removal and site clearance during the final stage of jacket donation, which involves a change of ownership and the transfer of title through a deed of ownership from industry to Louisiana and into the artificial reef program. The expected savings are determined by the state, and Louisiana has predetermined where and how this money would be used through its artificial reef planning and law. These payments are often channeled toward the agency in charge of fisheries and fishing monitoring [33].

We chose to present a case study on offshore decommissioning due to the inherent scarcity of currently available onshore examples. While offshore decommissioning projects have been well-documented and analyzed, the landscape for onshore decommissioning is notably different. As of the present research, there are very few documented instances of onshore decommissioning projects available for comprehensive analysis. Consequently, the selection of a representative onshore case study for detailed examination proved challenging.

This scarcity of onshore examples highlights a critical gap in the existing literature and industry documentation. While offshore decommissioning has been the subject of numerous studies, conferences, and publications, the onshore counterpart remains a relatively understudied and underreported aspect of the decommissioning process.

The absence of comparable onshore case studies serves as a reminder of the need for increased attention and research in this domain. As the industry evolves, it is imperative to bridge the gap in knowledge regarding onshore decommissioning to ensure a comprehensive understanding of sustainable practices in both environments.

5. Geothermal energy resources in oilfields

Oil and geothermal energy are two types of resources that coexist in sedimentary basins. Sedimentary basin oilfields are also rich in geothermal resources, having substantial geothermal energy in their deepest sections. The circumstances for hydrocarbon generation are quite similar to those seen in geothermal fields in hydrocarbon basins. Groundwater is always present in the primary and secondary migration of oil and gas to the reservoir, and hydrocarbon is generated at a certain temperature. Groundwater is also regarded as a working fluid in the conduction and convection of geothermal energy in the Earth's crust. As a result, there is an interdependence between groundwater, hydrocarbons, and geothermal energy. In petroliferous sedimentary basins, hydrocarbon reservoirs often also considered as geothermal reservoirs. In circumstances where reservoirs have oil on top and water on the bottom, or interbedded oil and water layers correlate to coexisting hydrocarbon oilfields and geothermal fields, the generated water acts as a significant geothermal resource. In general, geothermal reservoirs are substantially larger in volume and contain more resources than hydrocarbon reservoirs in oilfields. As a result, the overall quantity of geothermal resources in these oilfields exceeds the entire amount of hydrocarbon resources. However, it is vital to highlight that geothermal resources have a lower energy density than hydrocarbon resources [34].

Oilfield geothermal resources that coexist with hydrocarbons in sedimentary basins are classified as intermediate to low temperature, with fluid temperatures ranging from 65°C to 150°C [23]. Not only do massive volumes of geothermal energy exist in oil and gas reservoirs, but oilfields provide great benefits in utilizing that geothermal energy.

As geothermal resources in oil and gas reservoirs have been examined continually, significant amounts of geothermal reserves have been documented in worldwide oilfields [34][35]. McKenna et al. [36] investigated that co-produced fluids in Gulf Coast oilfields could generate over 1000 MW of electric power. Limpasurat et al. [37] explored the prospect of utilizing significant heat stored in heavy oil fields subjected to steam flooding, suggesting a potential power generation of approximately 14 kW from a single injector-producer system. Bennett et al. [38] approximated that oilfields in the Los Angeles basin might yield around 7430 kW of net geothermal power, accompanied by a Net Present Value (NPV) of 41 million dollars over three decades. Additionally, Sanyal et al. [39] indicated that co-produced water from an abandoned gas well along the U.S. Gulf Coast could potentially generate 350 kW of geothermal power. Some wells in Texas, Oklahoma, and Louisiana have quite high bottomhole temperatures (150°C-200°C). Major basins in China, such as Daqing Oilfield, Liaohe Oilfield, and Huabei Oilfield, have also been claimed to be rich in geothermal resources [34]. More importantly, when it comes to harnessing geothermal resources, oilfields offer particular economic and technological advantages. Because of the existing wellbore, surface facilities, and data, the oilfield geothermal project can be done at a lesser cost, with less risk, and with greater convenience [35].

Benefits of converting existing oil wells into geothermal wells

As it is mentioned above, oilfields can offer enormous benefits for developing geothermal energy utilizing existing wellbores and infrastructure. Here are some details about those benefits:

- Available geothermal resources in oilfields:

Hydrocarbon exploration has shown not only the value of hydrocarbon resources in sedimentary basins, but also the presence of rewarding geothermal resources. The distribution of geothermal water resources is frequently found in tandem with hydrocarbon exploration and development in sedimentary basins. When oil is recovered from production wells, the water that is generated along with the oil carries a large quantity of heat. This water, also known as oilfield generated waste water or oilfield sewage, is heated when temperatures rise deeper into the earth's crust, where hydrocarbon reserves are found.

According to geothermal resource categorization, the temperature of oilfield generated water is normally a useful medium and low-temperature geothermal resource. Based on geological structural attributes, this type of geothermal resource comes under the sedimentary basin geothermal resource category, defined by its hydrothermal nature and carrier, which is a water-oil-gas combination mostly constituted of oilfield injected water [40]-[42].

- Minimized cost and risk:

Geothermal energy produced from oil and gas wells is a cost-effective technology. Because a wellbore with proven integrity is already existent, no or minimal drilling is required. Traditional geothermal well drilling costs, on the other hand, can account for up to 50% of overall cost. The existing wellbore would save money and minimize risk in drilling and completion operations. Moreover, the cost savings extend beyond the wellbores themselves. Oilfields are equipped with an array of surface facilities that have been established to support hydrocarbon production. Existing surface infrastructure, such as installed wellsite facilities, pipelines, and service roads to the wellsite, might reduce the initial outlay even further. Even for those wells or facilities that require just minor upgrades, only a minimal expenditure is necessary to get the project started [35].

Due to the extensive data collected during long-term oil and gas exploration and production, valuable insights are available for mitigating risks and uncertainties associated with geothermal resource estimation. A notable advantage of repurposing oil and gas wells into geothermal wells stems from the existing investments in reservoir characterization, geomechanical modeling, and productivity analyses aimed at optimizing oil and gas extraction. These studies often require substantial lab testing and data acquisition, including seismic data, which can be capital-intensive but are potentially accessible at little to no cost for future repurposing projects. Moreover, by capitalizing on this wealth of existing data, the uncertainty related to reservoir characteristics can be further minimized through comprehensive reservoir characterization.

A widely applied method for estimating thermal resources in geothermal reservoirs is volumetric resource estimation. In this context, fluid saturation plays a crucial role in accurate estimation. However, in oil and gas reservoirs, fluid saturations are not constant; they can vary over time due to factors such as hydrocarbon production. For instance, while water saturation may increase, oil and gas saturations may decrease to some extent. These variations can lead to errors in geothermal resource estimation within oil and gas reservoirs .

Fortunately, the extensive oilfield databases offer a valuable resource in overcoming these challenges. These databases not only provide information on oil, gas, and water saturations but also capture the dynamic changes that occur over the production history. This wealth of data enables operators to accurately evaluate the geothermal reserves at any specific point in the production timeline. By leveraging this knowledge, operators can make informed decisions regarding geothermal projects, ultimately leading to more effective and successful outcomes [43][44].

- Number of abandoned wells:

Oilfields offer ample opportunities for geothermal utilization, particularly in mature fields characterized by a substantial number of high water cut wells resulting from water flooding, as well as abandoned wells due to inadequate production. Despite these wells having lost their economic value in the context of traditional oil and gas extraction, they represent promising candidates for harnessing geothermal resources. For instance, in Texas, the Texas Railroad Commission's database reported 10,370 abandoned and plugged wells in 2016, while China accounted for a significant number of abandoned wells out of a total of 164,076 oil and gas wells [45].

Within this pool of potential candidate wells, operators have the advantage of selecting those with specific attributes to optimize geothermal energy production. High water-cut wells with elevated bottomhole temperatures and substantial production rates are particularly well-suited for geothermal conversion. The presence of excess water production in these wells indicates the potential for accessing higher-temperature reservoirs, making them prime contenders for efficient geothermal energy extraction.

Additionally, operators can identify abandoned wells with reliable wellbore integrity and high bottomhole temperatures. These wells may have been deemed unproductive in traditional oil and gas operations, but their geological characteristics make them ideal candidates for repurposing as geothermal energy producers. For example, In China (Huabei Oilfield) a noteworthy initiative by refurbishing two abandoned wells has been undertaken These wells have been repurposed to extract geothermal water for heat-tracing gathering and transportation purposes. This innovative approach results in substantial daily savings of approximately 5 tons of oil and 3.5×10^3 m^3 of gas [35].

- Market of oilfield geothermal utilization:

Oilfields serve not only as energy producers but also significant energy consumers. They heavily rely on the burning of oil, gas, and coal in order to generate heat for various purposes, such as residential heating, thermal recovery of heavy oil, and oil gathering and transportation processes [34]. For an instance, dehydration of crude oil and transportation necessitate heating, with particular emphasis on heating heavy oil to reduce its viscosity for pipeline transportation. However, these operations come with substantial energy consumption and high operation costs, exemplified by the case of 2 crude oil gathering stations in North China that incurred $503,000 per year on electricity and gas consumption [46]. The considerable demand for thermal energy in oilfields creates a vast market for oilfield goethermal utilization, especially in aging oilfields where the need for efficient and sustainable energy solutions is even more pronounced.

Based on incomplete data, it has been observed that oilfield furnaces and boilers consume at least 1.0×10^6 tons of crude oil and 30×10^8 m^3 gas annually, resulting in increased operating and living costs. Moreover, the volume of annual oilfield produced water is higher than 7×10^8 m^3 and contains valuable medium and low-temperature geothermal energy which can be utilized directly. Through heat pump technology, extracting 10 degrees celsius thermal energy from this water can yield an amount equivalent to approximately 1.3×10^6 tons of standard coal or an oilfield's annual oil production of 0.9×10^6 tons. This significant amount of heat signifies the remarkable potential of these geothermal resources in contributing to the energy needs of oilfields [34].

- Engineering technology advantages in oilfields:

Drilling, testing, hot water transportation, water treatment, and surface engineering are all traditional oilfield technologies that may be applied to geothermal energy extraction. The experience of oilfield workers, together with the application of oilfield technology and equipment, provides favorable circumstances for geothermal energy utilization. Surprisingly, geological data gathered during petroleum research may be used to evaluate geothermal resources, and geophysical exploration and hydrocarbon development technologies provide feasible alternatives for effective geothermal energy extraction. Deep well drilling and hydrocarbon reservoir fracturing techniques may also be applied to construct Enhanced Geothermal Systems (EGS) reservoirs from deep hot dry rock, boosting oilfield firms' distinct edge in geothermal energy extraction [47].

- Government and company support:

The efforts of the government and oil industry have created an advantageous environment and extraordinary chance to increase geothermal use. China, for example, is rapidly developing incentive policies and boosting investment to support the growth of geothermal energy. Petroleum companies, which have historically concentrated only on extraction of gas and oil, have realized the potential of geothermal resources and have started to search for ways to produce geothermal energy from wells that are already in place. Companies like Denbury Resources, Continental Resources, and Hilcorp Energy have tested geothermal systems during regular production in order to recover heat alongside hydrocarbons [47].

As mentioned earlier, the inherent benefits that oilfields possess for harnessing geothermal energy suggest a bright outlook for the utilization of oilfield geothermal resources. These advantages hold the potential to meet thermal energy requirements, prolong the economic viability of oilfields, and mitigate operational expenses.

6. Conversion of abandoned oil wells for geothermal energy purposes

Converting abandoned oil and gas wells into geothermal wells presents a promising option to extend the economic viability of these wells and address decommissioning-related challenges. Leveraging the well-documented data logs from their active operation makes the conversion process smoother. Numerous pilot initiatives that repurpose abandoned oil and gas wells for geothermal extraction have been finalized, while others are in advanced stages of development. In the following sections, we assess these projects individually, categorizing them into two main groups: open-loop systems (including enhanced geothermal systems) and closed-loop systems.

Open-loop geothermal energy systems

As shown in Figure 8, geothermal energy may be extracted using either open-loop or closed-loop systems. Open-loop necessitates the use of many wells, some of which will be used to inject the working fluid (as injection wells) and others to collect the working fluid (as extraction wells). Because of the direct contact of the working fluid with the hot rock and the larger heat transfer surface, this design often delivers higher energy extraction. However, it is only possible if at least two wells are close [48]. Alternatively, it would be necessary to drill new wells to finalize the loops. The primary difficulty in such setups revolves around the gradual decrease in reservoir pressure over time and the concurrent extraction of hydrocarbon fluids alongside hot water, necessitating additional treatment to meet environmental regulations. Furthermore, further fracking may be required for establishing flow pathways from the injection wells to the extraction wells. Aside from the added expenditures, fracking is a sensitive procedure that must be handled with care. Incorrect fracking may result in the loss of injected fluid and, in the event of hazardous injected fluid, serious environmental damage [48].

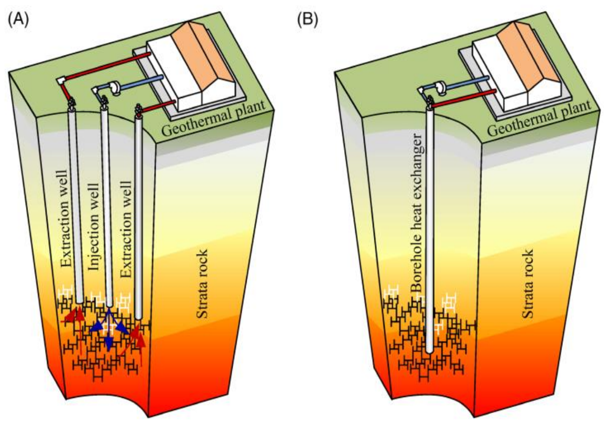

Figure 8. Illustration of Open-Loop (A) and Closed-Loop (B) Geothermal Energy Extraction [48]

<u>Enhanced Geothermal Systems – (EGS)</u>

It's essential to note that most of wells lack natural underground reservoir resources, necessitating the injection of artificial working fluids. To overcome these challenges, the Hot

Dry Rock (HDR) method is predominantly used, which involves extracting geothermal resources from dry or water-absent reservoirs. The HDR concept has evolved into the Enhanced Geothermal Systems (EGS) approach, first applied in 1977 at Fenton Hill [49].

EGS involve the creation of an artificial reservoir where substantial heat is present, although natural permeability and fluid saturation are lacking. The EGS procedure focuses on establishing a subsurface network of fractures that allow continuous water circulation between injection wells and production wells for heat extraction. The development of an EGS necessitates enhancing the natural rock permeability. Initially, water is injected through injection wells into induced fractures, where it is heated upon contact with the rock. Subsequently, water is produced via production wells (fig. 9) [50].

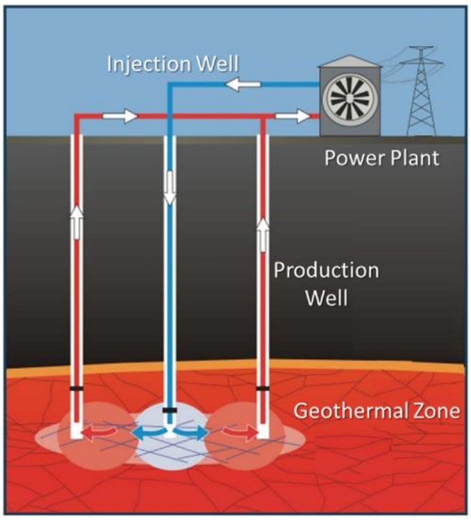

Figure 9. Illustration of EGS with three wells [50].

In contrast to other geothermal techniques, EGS reservoirs offer a distinct advantage due to their access to more plentiful heat following the creation of artificial fractures in the hot subsurface and subsequent fluid injection. However, the costs associated with drilling, completing, and establishing hydraulic EGS wells are notably high, amounting to approximately $10 million per well. Consequently, the conversion of abandoned unconventional hydrocarbon wells with multi-stage fracturing completions has been explored as an option to harness EGS reservoirs.

These EGS projects are marked by considerable expenses, involving substantial volumes of working fluid and challenging drilling and completion processes in previously uncharted terrains. Although ongoing research seeks innovative design solutions to enhance project viability, repurposing existing oil and gas wells, which are already hydraulically fractured, emerges as an appealing alternative. Despite this, there have been no fully realized EGS projects originating from abandoned oil and gas wells. A feasibility study conducted in West Virginia, aimed at repurposing extensively fractured oil and gas wells, concluded that the project could not compete with prevailing US electricity prices, even when considering district heating applications. For EGS development from oil and gas wells to be economically competitive, it necessitates a reduction in financial risk by demonstrating reliable reservoir performance and proximity to end-users [50].

Closed-loop geothermal energy systems

In contrast, the closed-loop architecture may provide less heat extraction performance than the open-loop equivalent. However, no further drilling or fracking is required since the heat is taken from the current well, which works as a wellbore or borehole heat exchanger. Figure 10 displays two types of weelbore heat exchangers (WBHEs) often employed in closed-loop systems: Co-axial and U-tube heat exchangers [51]. An U-tube heat exchanger must be fitted before filling the abandoned well with materials having adequate thermal properties.

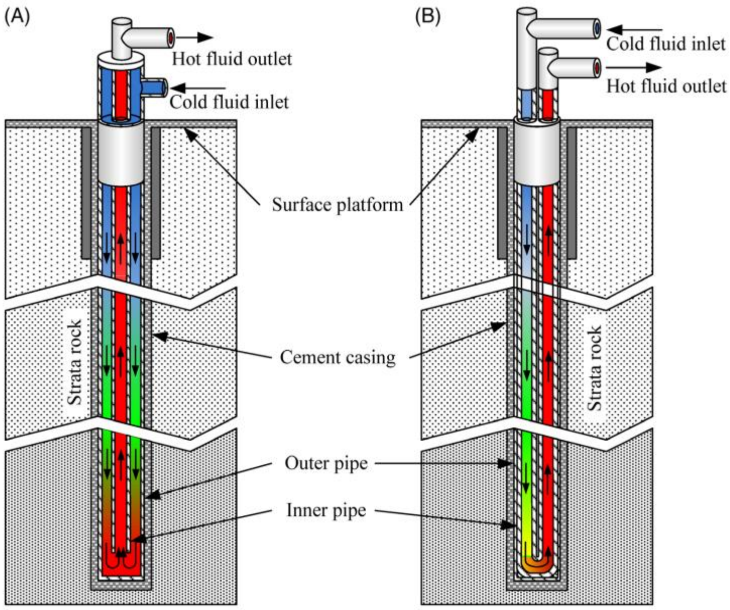

Figure 10. Co-axial (A) and U-tube (B) heat exchanger in retrofitted oil well [51].

In practical applications, the U-tube configuration is mostly used in shallow wells, specially in space heating and cooling [52]. It can be implemented with a single U-tube or multiple ones. On the other hand, double pipe heat exchangers utilize the existing well's outer pipe as the annulus, while a smaller insulated pipe is inserted inside to create a coaxial setup. Consequently, insulating materials such as polyethylene or polystyrene are incorporated into the pipe's structure. The Co-axial heat exchanger has a bigger heat transfer surface area than the U-tube, which may result in superior heat extraction performance. Furthermore, because of its wider annulus diameter, it has a smaller pressure drop penalty and requires less pumping power for the same injected mass flow rate. For converting abandoned oil wells, the double pipe heat exchanger is preferred over the U-tube since it allows for reuse of the existing casing, reducing installation costs and construction time. The double pipe heat exchanger's coaxial design also minimizes the thermal resistance between the circulating fluid and the wellbore. There have been successful analysis of double pipe heat exchangers in deep wells, such as in the Villafortuna Trecate oilfield in Europe [53].

In 2021, a significant milestone was achieved as the initial closed-loop geothermal well conversion from an abandoned oil well in Hungary was accomplished by MS Energy Solutions. This achievenment involved the successful transformation of a deep wellbore, originally drilled in the 1960s in Kiskunhalas, Hungary, yielding a heat output of 0.5MWt. Notably, demonstration initiatives in the US and Slovenia are currently progressing through advanced stages and are poised to initiate testing in the near future [50].

Variables affecting geothermal energy production using closed-loop systems

The circulation system comprises various elements capable of controlling the working fluid's temperature. Factors affecting temperature regulation include the outer and inner wells, the working fluids, injection temperature, alterations in flow rate, and geological layering. Assessing how these variables impact on the system's total energy output is crucial for optimizing efficiency because efficiency hinges on the temperature differential between the injected and extracted working fluid. In this section, we review existing literature to gain insights into the effects of these components and present findings from various research studies.

Well size

An essential parameter to investigate when examining heat extraction in a co-axial well is the sizing of various well components, specifically, the well's diameter and the inner tubing. The significance and correlation between the size of the inner tubing and the outer casing are detailed in the study conducted by Wang et al. [54]. This research delves into how the well radius influences the extraction of thermal energy. The experimental findings demonstrate that an increase in the outer casing's size leads to a proportional rise in generated thermal power, indicating an almost linear relationship.

One possible explanation for this increasing correlation between thermal power and the increment in the outer casing's radius is the larger contact surface area between the working fluid and the surrounding subsurface, facilitating more efficient heat exchange. This, in turn, results in a swifter dissipation of heat from the surroundings, leading to a higher thermal power output. A similar (almost) correlation can be observed when the inner tubing radius decreases. Enlarging the inner tubing reduces the available volume within the well for the working fluid to traverse. This diminished volume, combined with the same quantity of working fluid, results in a higher flow rate and reduced time for heat exchange, consequently yielding lower thermal power.

Insulation of the inner-tubing

The research conducted by Horne et al. [55], investigating the impact of insulation material on the inner tubing, serves as a benchmark experiment in this study. In their experiment, two different working fluids were injected into the DCBHE (Downhole Coaxial Borehole Heat Exchanger). Both of these working fluids experienced an increase in temperature as they flowed downward. It was observed that, the setup with insulation material exhibited a higher working fluid temperature at the surface. The purpose of the insulation was to minimize or eliminate cooling of the working fluid as it moved upward.

Morita et al. [56] explored the significance of thermal conductivity. It was demonstrated that having low thermal conductivity in the inner tubing is crucial to achieving a substantial difference between injection and production temperatures. This temperature difference is indicative of the efficiency of heat transfer from the subsurface to the surface.

The characteristics of the inner tubing, such as, its thickness, material, and design, can vary and have a direct impact on production temperatures. Effective insulation of the tubing is essential factor for efficiently transferring heat to the surface. Without insulation, heat would be lost to the cold injection water. This signifies the importance of employing high-quality insulation with low thermal conductivity. When the tubing has low thermal conductivity, it's expected that heat will be transported to the surface with minimal losses.

Flowrate and injection temperature

A study conducted by Wight et al. [57] has provided insights into the impacts of varying flow rates and injection temperatures. When it comes to higher flow rates, there is minimal heat loss within the initial 1500 meters of well depth. Conversely, lower flow rates exhibit heat loss, particularly when the inlet temperature exceeds the temperature at the wellbore depth.

In scenarios where the inlet temperature is low and the flow rate is high, the temperature of the working fluid remains relatively stable within the first 1000 meters. However, if the inlet temperature is high and the flow rate is low, the working fluid has more time to engage in heat exchange with the surrounding layers, resulting in a reduction in fluid temperature during the initial 1000 meters of depth.

Based on the findings of this study, it is advisable to maintain a low inlet temperature to maximize the efficiency of heat extraction.

Pump requirements

A Downhole Coaxial Borehole Heat Exchanger (DCBHE) necessitates pumping for the injection and extraction of the working fluid. Therefore, it's essential to calculate the power consumption of the pump within this system. The pump's power is employed to facilitate the circulation of the fluid, primarily to overcome friction and differences in hydraulic head.

Additionally, the relative pumping power serves as a crucial efficiency indicator. If the power required for pumping is significantly high when compared to the power generated by the DCBHE, it signifies that the overall system is operating inefficiently.

Closed-loop geothermal energy systems: case study analysis

Reference [58] analysed the the Grouw-01 well, situated in an industrial area and drilled to a depth of 1927-1937m to access a hydrocarbon reservoir primarily containing methane gas. It is positioned between the Vlieland basin and the Friesland platform in the Netherlands.

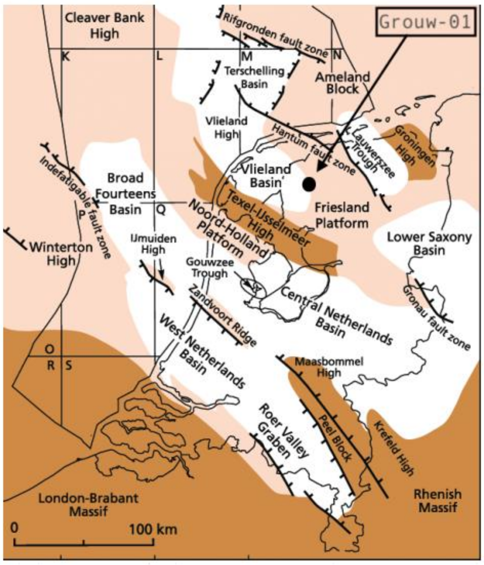

Figure 11. Map of structural elements for late Jurassic to early Cretaceous. (Dark brown - structural highs, light brown - platforms, white - basins) [59]

To facilitate its use as a co-axial heat exchanger, the well's bottom required cementing. While a depth of 2000m is chosen for simulation, safety regulations might lead to an actual bottomhole depth of 1800m or 1850m during well cementing.
The subsurface model, simulated using COMSOL Multiphysics, incorporates geological characteristics and well data from Vermillion and existing literature. Key properties influencing heat transfer, such as heat capacity and thermal conductivity of materials, working fluids, and rocks, are considered. For simplicity, uniform cementation is assumed, despite variations in actual cementation in Grouw-01.

The geological model simplifies layering, focusing on three dominant layers: sandstone, siltstone, and limestone, each with distinct thermal conductivity values. These layers are connected in a 2D axisymmetric model. Cement between the casing and geological layers enhances overall thermal conductivity, although the thin cement layer's impact is expected to be minor.

COMSOL Multiphysics, chosen for its finite element method, employs a 2D axisymmetric model to balance computational efficiency with accuracy. The mesh grid is finer near the axial symmetry point and coarser toward the ends to optimize computational time while maintaining accuracy.

Analysis of the mono-well co-axial heat exchanger's potential energy involves understanding physics and design elements. Grouw-01 serves as a case study, with its exact geometry replicated in COMSOL based on materials, geology, and well design. The model is a simplification of the real geology, focusing on the largest three layers, each assumed to have homogeneous properties.

Sensitivity analysis explores parameters affecting heat exchange, including flow rate, working fluid, inner-tubing material and thickness, outer-tubing thickness, well depth, injection temperature, and reverse injection flow. Results provide insights into the depth-temperature relationship, production temperature, generated power, COP, CSP, and net power, aiding in optimizing the design and performance conditions for the dual concentric borehole heat exchanger (DCBHE).

Base case

In establishing a baseline for comparison, a base case simulation was devised. This case, using a mass flowrate of 1 kg/s (approximately 86.4 m^3/day), employs water as the working fluid due to its abundance and minimal environmental impact in case of system leakage. The injection temperature of 12°C aligns with the average surface temperature around the Grouw-01 well and the Netherlands throughout the year (15°C and 10°C, respectively).

The inner-tubing material chosen is vacuum insulated tubing (VIT), known for its low thermal conductivity. VIT, consisting of two layers with a vacuum in between, exhibits varying properties across different companies; for this study, an average estimation was adopted.

Why is this sensitivity analysis necessary for us?

This analysis delves into vital parameter variations aimed at enhancing the power and efficiency of the DCBHE, with a specific focus on temperature, power, and system efficiency. The objective is to conduct sensitivity analyses, identifying optimal design conditions for the system.

Flowrate adjustments are investigated initially. An increased flowrate reduces the time for heat exchange between the working fluid and surrounding rock, leading to a potential decrease in production temperature. However, considering the interdependence of temperature and power generation on flowrate, an increase could yield higher power generation. This analysis seeks to pinpoint the ideal flowrate for optimized power generation.

The choice of working fluid holds significance in the thermal properties affecting heat transfer. Water, glycol, and diathermal oil are compared, and theoretical property changes in water's thermal conductivity and heat capacity are explored. The simulation revealed insights into an ideal working fluid.

Inner-tubing materials, including polypropylene, polyethylene, and VIT, are analyzed for their impact on minimizing cooling during fluid transport. VIT is further scrutinized for changes in thermal conductivity and heat capacity to identify a range for minimal heat loss. Altering the thickness of VIT is considered to influence flowrate and heat exchange.

Increasing surface contact area between the working fluid and outer-tubing is explored to enhance heat extraction. A larger outer-tubing diameter is expected to improve overall performance by facilitating increased heat exchange.

Analyzing different well depths provides insights into the relationship between well depth and production temperature, power, COP, and CSP, anticipating linear performance changes with depth variations.

Surface factors, such as seasonal temperature fluctuations, are considered, with different injection temperatures simulated. Higher injection temperatures can induce cooling before stabilization and heating. In summer, the system can function as a cooling source by switching the inlet and outlet, allowing the working fluid to cool during transport to the surface. This comprehensive analysis covers both subsurface and surface factors, essential for understanding the system's dynamic behavior and optimizing its performance.

Results of analysis

In this analysis, the author took a close look at how different factors affect the performance of the geothermal well. The journey began with a careful examination of flowrates of 0.25 kg/s, 0.5 kg/s, 1 kg/s, also 2.0 kg/s. The investigator noticed that higher flowrates, like 2 kg/s, led to the bottomhole temperature decrease because of less heat exchange with surrounding rock, on the other hand there was also a lower heat exchange with the inner tubing during upward flow. On the flip side, slower flowrates (0.25 kg/s and 0.50 kg/s) seemed to contribute to more heat loss during upward flow, although they also gain more heat while downward move in comparison with higher flowrate. However, the author found a sweet spot with optimal flowrates, where a smooth exchange between the inner tubing and fluid during downward flow resulted in the highest bottomhole temperature. From point of power generation, the coefficient of performance is higher at 0.50 kg/s showcasing the importance of selecting the right flowrate to balance heat exchange, power generation, and overall system efficiency.

Shifting attention to working fluids, the author compared water, ethylene glycol, and diathermic oil. Although, glycol, with its slightly lower heat capacity but double the thermal conductivity of diathermic oil, turned out to be the winner, achieving the highest bottomhole temperature. Thermal conductivity, however, has a limited impact on production temperature, with a slight increase in BHT observed. Power generation is significantly influenced by heat capacity as wel, as fluids with higher capacity generate more power. Density also affects power generation, leading to substantial differences in output even with more or less similar heat capacity, as seen between glycol and diathermic oil. Although, the number of investigated fluids were not sufficient to pick the most beneficial fluid, it was clear that diathermic oil is the least efficient for heating systems due to its low production temperature and power consumption.

Moving on to insulation materials, the author looked at polypropylene, polyethylene, and Vacuum Insulated Tubing (VIT). Polyethylene stood out for its influence on both downward and upward flows. It was mentioned that, during downward flow the working fluid is heated by both inner and outer tubing, also during upward flow lose heat to insulation material, facilitated by polyethylene's high thermal conductivity. However, the results of analysis on heat capacity change of VIT emphasized that, for insulation materials, what mattered most was thermal conductivity rather than heat capacity, showing that materials with high thermal conductivity had lower insulation efficiency. This underscores the critical role of thermal conductivity in determining the effectiveness of insulation materials.

When exploring the impact of varying inner-tubing thickness of 0.017 m, 0.022 m and 0.035 m, the author's simulation reflected a delicate balance between thermal transport and thickness adjustments. A thicker VIT results in a slightly lower BHT but marginally higher production temperatures compared to the base thickness. The increased VIT size accelerates fluid movement, reducing heat exchange time during upward flow. Enhanced insulation thickness correlates with augmented power generation, with a notable 6kW gap between 0.017m and

0.035m thicknesses. Thicker insulation seemed to be linked with increased power generation and better system performance aswel, underlining the crucial role of insulation thickness in optimizing geothermal well efficiency.

The investigation into outer-tubing diameter (0.16 m, 0.18 m, 0.22 m and 0.30 m), a factor affecting subsurface contact and fluid travel, revealed trade-offs. Enlarging the outer tubing not only expands subsurface contact for working fluid interaction but also increases the volume for fluid travel, resulting in decreased velocity with constant injected mass. These factors collectively influence heat transfer between the working fluid and the surrounding rocks. Larger well sizes contributed to higher bottomhole temperatures, production temperatures, and power generation. However, the author noted that the power difference between well diameters of 0.16m and 0.30m was a modest 10kW, suggesting a need for a balanced approach.

As the analysis delved into well depths, varying from 1km to 4km, a linear relationship emerged, indicating that deeper wells promised not only higher bottomhole temperatures but also increased power generation. Although deeper wells offer more cooling time to the working fluid while moving inside the inner tube, however deeper wells exhibit a relatively higher BHT for the same geothermal gradient. For instance, while the 1 km well reaches a BHT of around 25℃ with a geothermal temperature of 45℃, the 4km well achieves 105℃ BHT with a geothermal temperature of 145℃. This finding highlighted the efficiency gains associated with maximizing well depth.

Temperature intricacies came into play with varying injection temperatures, mirroring the seasonal fluctuations in weather. Although lower injection temperatures (such as 7℃) are tend to have higher power generation, higher injection temperatures (such as 32℃) show higher Coefficient of Performance (COP) and Coefficient of System Performance (CSP). A nuanced dance unfolded, with injection temperatures of 12-22℃ emerging as a balance point, offering optimal performance across key metrics like COP, and CSP, and power generation.

In a bold twist, the author explored reversing the injection and production processes during the summer season, turning the well into a cooling source. In reverse injection flow, working fluid with lower flowrates have more time to cool, on the other hand higher flowrates tend to produce more power. The outcomes varied with flowrates, demonstrating the dynamic nature of geothermal systems under altered operational paradigms.

This study proposed by reference [60] explores the feasibility of adapting a double-pipe heat exchanger system for repurposing an abandoned petroleum well. The objective is to have a working fluid circulate within the well, capturing heat from deep underground and transporting it to the surface for various applications. Given that the petroleum well is no longer in use and has been sealed with casings, with a defined wellbore, a smaller diameter pipe, referred to as a "geostring," is installed to establish a closed-loop system for fluid circulation.

To initiate the process, cold working fluid is injected into the space between the well's inner and outer pipes from the surface. As this working fluid moves downward through the annulus, it absorbs heat conducted from the geological formation until it reaches the end of the outer pipe. Subsequently, the heated fluid enters the inner pipe, where it is circulated back to the surface. This method effectively extracts geothermal energy from the formation and brings it to the surface. The inner pipe is insulated to minimize heat loss as the warmer fluid ascends through zones with lower temperatures.

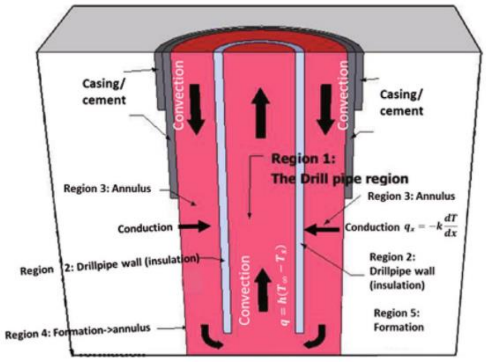

Figure 12. Schematic of the wellbore [60]

A sensitivity analysis is performed to enhance our comprehension of which configuration parameters significantly influence the total heat energy collected. The simulations involve a comparison of two factors: the outlet temperature of the extracted fluids and the heat accumulation within the well, as computed using Equation (1).

$$Q = (8)\ m\dot{C}_p \Delta T = m\dot{C}_p(T_{out} - T_{in}), \quad (1)$$

where m is the fluid mass, T_{in} is the inlet temperature of working fluid injected to the annulus, T_{out} is the outlet temperature of working fluid circulated out of the geostring, and ΔT is the temperature difference between the outlet temperature and the inlet temperature.

A sensitivity study was performed to better understand the critical design parameters that influence total accumulated heat energy. The simulations compared the extracted fluids' output temperature and heat buildup within the well, as determined by equation 1.

Results of the analysis

The parameters scrutinized in this analysis encompass the density, thermal conductivity, specific heat capacity, viscosity, inlet temperature, insulation effect, and geostring diameter.

In their sensitivity analysis, Sui et al. [67] noted that density exerts minimal influence on the outlet temperature, demonstrating a mere 1.96°C difference when density increased from 800 kg/m³ to 1600 kg/m³. This 100% difference in fluid density resulted in a 2.48% decrease in outlet temperature. Moreover, the heat energy exhibited a similar decreasing trend with density.

The researchers also discovered that increasing thermal conductivity improves heat exchange between the working fluid and the geological formation. Higher thermal conductivity leads to a more substantial heat gain. Consequently, the outlet temperature after one circulation rises predictably. However, the rate of heat obtained diminishes for higher thermal conductivities compared to the escalated temperature rate. For instance, an increase in thermal conductivity from 0.3 W/m°C to 5.0 W/m°C resulted in an outlet temperature increase from 63.02 to 87.38°C. Hence, fluid thermal conductivity emerges as a critical factor affecting heat transfer in the wellbore.

Examining specific heat capacity, the analysis by Sui et al. indicated that a 267% increase from 1500 J/kg°C to 5500 J/kg°C leads to a 33% decrease in outlet temperature (from 79 to 53°C). While lower heat capacity yields a more favorable outcome in terms of higher outlet temperature, the reverse trend is observed for heat energy gained. This underscores the significance of considering thermophysical properties when selecting the working fluid.

In their study, Sui et al. emphasized the substantial impact of viscosity on convective heat transfer. As viscosity increases, the outlet temperature rises significantly. For instance, a viscosity increase from 0.005 Pas to 0.1 Pas resulted in a dramatic 98.9% temperature increase. This rise in outlet temperature corresponds to an increase in heat energy as fluid viscosity approaches higher values.

Optimal setting of the inlet temperature is crucial, depending on the intended use of geothermal heat. The analysis demonstrated a linear increase in outlet temperature by raising the inlet temperature from 0 to 60°C. Sui et al. showcased that an inlet temperature of 60°C yields an outlet temperature of 90.11°C, while an inlet temperature of 0°C results in an outlet temperature of 71.93°C.

The inevitability of heat transfer through conduction prompted considerations for insulation. Sui et al.'s analysis revealed that varying insulation degrees on the geostring result in a substantial increase in outlet temperature (approximately 182%) when insulation changes from 0.01 W/m°C to 0.00005 W/m°C. This underscores the potential cost-efficiency of achieving a significant temperature increase through effective insulation.

Concerning geostring diameter, the study pointed out that increasing the diameter results in higher outlet temperatures and increased heat extraction from the well. Proper insulation becomes crucial to prevent heat transfer from the geostring to the annulus. The trend indicates a higher outlet temperature and greater heat energy extraction when the diameter is increased.

The research recommended by reference [61] attempts to investigate the possible use of abandoned oil and gas wells in California for geothermal energy extraction. The California Department of Conservation, Division of Oil and Gas and Geothermal Resources (DOGGR) data indicates approximately 147,127 abandoned, plugged, buried, or inactive wells in the state.

The study focuses on the feasibility of implementing deep Borehole Heat Exchanger (BHE) installations in these abandoned wells across California. Utilizing crustal heat flow data, it suggests that many existing wells could be deepened beyond 2000 meters to harness geothermal energy from >100 °C sandstone and shale rock for electricity production.

A physics-based mathematical model is constructed based on well depths and crustal thermal gradients encountered in coastal regions such as Santa Clara, Santa Barbara, and Monterey. The objective of the deep BHE model is to estimate abandoned well depths and thermal gradients required for achieving a 40 °C production fluid temperature.

Coastal areas like Santa Clara, South Monterey, and North Santa Barbara are identified as having medium to high heat flows and numerous abandoned wells. Measurements in Santa Clara show an average thermal gradient of 5.8 °C/100m. In Santa Clara, a 1220m deep well could encounter 70 °C rock, and deepening by 1000m may promise 130 °C rock. Similar temperature gradients are reported in South Monterey and North Santa Barbara.

Counties with lower to medium heat flows, such as Kern, Ventura, Fresno, and Los Angeles, also host many abandoned wells. In Kern, a temperature survey on an abandoned well indicated a gradient of 3.6 °C/100m. Ventura reported a gradient of 2.2 °C/100m with a high bottom hole temperature of 49 °C at 960m. Los Angeles might have lower temperature gradients, but isolated cases in the Palos Verdes basin show favorable values of 5.5 °C/100m.

<u>Feasibility study of DCBHE</u>

The study explores the viability of repurposing abandoned oil and gas wells as deep Borehole Heat Exchangers (BHEs) through mathematical modeling of fluid flow within a coaxial BHE configuration. Convective and conductive heat transport between the incompressible fluid and the surrounding rock matrix are accounted for in the model. The investigation establishes a parameterized envelope of desirable crustal temperature gradients, well depths, and flow rates based on observed characteristics in Santa Barbara, Santa Clara, and Monterey, California, USA.

The finite element method in COMSOL Multiphysics software is employed to numerically solve the equations governing fluid flow and heat transport. The domains are discretized in 2D, with the final solution being axisymmetric. Well depths of 1000, 3000, and 5000 m are modeled to align with those encountered in Santa Barbara, Santa Clara, and Monterey counties. The dimensions of the coaxial BHE configuration mirror those of existing abandoned wells of interest, with outer and inner diameters set at 180 mm and 120 mm, respectively.

Boundary conditions at the edges are parameterized to temperature gradients of 4.5 and 7.0 °C/100m, consistent with observed ranges in Santa Barbara, Santa Clara, and Monterey. The inlet mass flow rate of the coaxial heat exchanger is parametrized at 1, 4.4, and 10 kg/s, corresponding to the heating demand of a single commercial building. The coaxial heat exchanger's outlet is adjusted to a constant pressure boundary condition of 0 Pa.

In summary, the study utilizes a total of 18 parameter combinations, encompassing well depths of 1000, 3000, 5000 m, mass flow rates of 1, 4.4, 10 kg/s, and edge temperature gradients of 4.5 and 7.0 °C/100m.

Results gained from feasibility study

This feasibility study assesses the potential production temperatures and flow rates achievable through the conversion of abandoned wells into deep Borehole Heat Exchangers (BHEs) in Santa Barbara, Santa Clara, and Monterey counties. Examining depths ranging from 1000 to 5000 m, temperature gradients from 4.5 to 7.0 °C/100 m, and flow rates from 1 to 10 l/s, the study reveals a diverse spectrum of fluid temperature increases spanning from 1.2 to 130 °C.

The analysis highlights the necessity of lower flow rates (1 l/s) to attain fluid temperature increases exceeding 10 °C in 1000 m deep wells. In deeper wells (approximately 3000 m), the crustal temperature gradient assumes a more significant role in achieving outlet fluid temperatures suitable for direct use. For instance, an increased subsurface gradient from 4.5 to 7 °C/100 m results in a 36.5% rise in production temperature for a 4.4 l/s flow rate in a 3000 m deep well. Flow rate emerges as a critical factor; transitioning from 1 to 10 l/s reduces the production fluid temperature by 40.7% for a 3000 m deep well with a 7 °C/100 m gradient. The impact of subsurface temperature gradient and flow rate intensifies with increasing well depth. Ultimately, the targeted well parameters span from 1250 m with a 1 l/s flow rate and 7 °C/100 m gradient to 5000 m with a 10 l/s flow rate and 4.5 °C/100 m gradient.

Concerning the Coefficient of Performance (COP), the analysis of various combinations of fluid flow rates, well depths, and subsurface temperature gradients reveals notable trends. Generally, COP increases with well depth but decreases with rising flow rates. Specifically, for a flow rate of 4.4 l/s, COP increases by 425% with well depth from 1000 to 5000 m, while for a 3000 m deep well, it decreases by 50% as the flow rate escalates from 4.4 to 10 l/s. Despite the overarching trend of an increasing COP with higher well depths, instances of decline occur at low flow rates and high well depths due to low Reynolds numbers, corresponding to higher friction factors.

Eavor closed-loop geothermal system

The Eavor-Loop is an innovative, fully integrated prototype of a closed-loop geothermal system boasting a unique downhole well design and exceptional thermodynamic efficiency. It consists of connecting two vertical wells, forming a well pair at significant depths, and integrating them with several horizontal multilateral wellbores that span several kilometers, effectively creating a closed-loop system. These horizontal sections are embedded in hot geological formations with temperatures of 100°C or higher. A working fluid circulates through this closed loop, extracting thermal energy, which can be either directly sold or converted into electricity for sale. Notably, it's a completely closed-loop system with no interaction with the surrounding rock formations and no discharge at the surface. It efficiently harnesses heat from the Earth's natural geothermal gradient, making it suitable for regions with common rock temperatures like warm sedimentary basins.

The key differentiator of Eavor-Loop compared to existing geothermal technology is its complete closed-loop nature. It operates as an underground pipe system, akin to a deep radiator or heat exchanger. This unique design offers scalability without the need for high-temperature volcanic hotspots, permeable aquifers, or hydrothermal flow capacity. Unlike Enhanced Geothermal Systems (EGS), which often involve fracking and induced seismicity, Eavor-Loop does not require fracking and is more predictable. It competes in markets for district heating, cooling, and dispatchable renewable electricity, offering both baseload and load-following capabilities, making it suitable for integration with wind and solar energy [62].

Eavor's target markets include district heating and cooling in cities, large-scale electricity generation projects, distributed electricity, remote communities (e.g., islands or northern regions), and the resiliency market (e.g., the US Department of Defense). Initially, it's focused on markets in Canada, the US, Northern Europe, and Japan, which together represent over 10 GW electric equivalent and align with Eavor's mission to power/heat 10 million homes in 10 years [62].

While closed-loop geothermal systems have been proposed and built at a small scale before, Eavor-Loop distinguishes itself with its substantial wellbore length in contact with hot rock, enabled by constructing a multilateral network and sealing the large multilateral section without casing [63].

Compared to traditional borehole heat exchangers, Eavor-Loop offers several advantages. Multilaterals increase the volume of rock that is harvested. Borehole heat exchangers often consist of concentric systems with around 500 meters of wellbore in contact with hot rock, limiting their efficiency and economic viability. In contrast, the commercial Eavor-Loop system has an impressive 50,000 meters in contact with hot rock, thanks to its use of multilateral wells. These multilaterals are more cost-effective to drill, as costs are distributed across multiple energy-mining laterals, offering economies of scale [63].

Eavor-Loop also employs a unique completion method for its horizontal multilateral sections, using a chemical setting agent combined with a tailored working fluid. This technique simplifies drilling, avoids the need for complicated and expensive multilateral junctions and casing, and ensures a standardized and repeatable approach [64].

Moreover, Eavor-Loop is designed for standardization, repeatability, and consistency, which, like wind and solar technologies, capitalizes on incremental efficiency gains and economies of scale. This approach distinguishes it from nuclear, hydro, or traditional geothermal methods. Oil and gas resource plays in North America have also employed similar strategies with significant success.

Eavor closed-loop system: case study analysis

The Eavor-Loop™ Demonstration Project [62], known as "Eavor-Lite," is situated west of Sylvan Lake, near the town of Rocky Mountain House, Alberta. This location features an average geothermal gradient and bottom-hole temperatures. The surface leases used for this project were originally employed for oil and gas operations, owned and operated by Certus Oil and Gas. Importantly, Eavor is not repurposing any of the existing wells.

Eavor-Lite serves as a full-scale prototype of the Eavor-Loop technology, aimed at de-risking its key technical components. The closed-loop system consists of a substantial U-tube shaped well at a depth of 2.4 kilometers. It incorporates two parallel multilateral horizontal wellbores each extending approximately 2,000 meters. A pipeline connects these sites on the surface. The drilling process involves the operation of two drilling rigs simultaneously, one from each site, to intersect the multilateral wellbores at depth. A water-based working fluid circulates in the inlet well, flows through the parallel wellbores, conducts heat transfer with the rock, and ascends in the outlet wellbore at a higher temperature. A thermosiphon effect, driven by the density difference between the inlet and outlet wells, powers the flow without the need for any pumping. A test facility on the surface manages solid removal, collects essential performance data, and cools the water for recirculation into the inlet well.

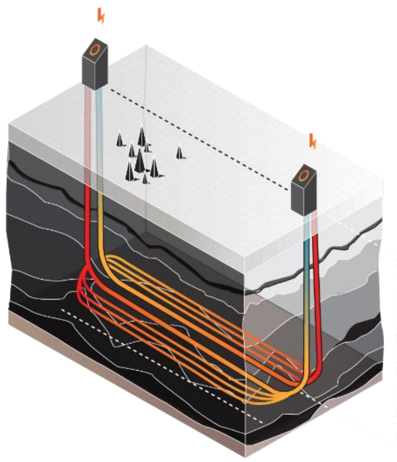

Figure 13. Eavor - Loop schematic [64]

The drilling of the Eavor-Lite project adhered to standard equipment and methodologies with only two notable exceptions: the use of magnetic ranging technology to intersect multilateral wellbores and the application of the Rock-Pipe™ chemical completion system for sealing purposes instead of traditional steel casing.

Magnetic ranging tools were integrated into the Bottom Hole Assembly (BHA) of both drilling rigs when they were within approximately 100 meters of each other. The target wellbore contains a receiver, and the subject well utilizes a magnetic solenoid emitter tool. These magnetic tools offer precise accuracy to home in on the target well and steer appropriately for intersections. Although magnetic ranging is not a typical operation in the oil and gas industry, it utilizes standard magnetic ranging and control technology and has been employed for various applications over the years. This marks the first instance, to the best of our knowledge, where it has been used to create a multilateral closed-loop geothermal network.

Eavor collaborated with Shear Fluids and other firms to develop a specialized drilling fluid system known as the Rock-Pipe™ completion system. This system is designed to seal the near wellbore porosity and permeability. The function of this drilling fluid differs depending on the rock type. In porous formations, such as sandstone (which is the focus of the Demonstration Project), the sealant does not merely form a thin film on the interior of the wellbore. Instead, it penetrates the pore space and natural fractures within the rock itself before setting into a solid state. The sealant fills the 10% porosity within the rock, and the material properties are primarily derived from the rock (90% rock, 10% sealant).

In contrast, in rocks with near-zero permeability, such as shale, the drilling fluid serves to create a mechanical and chemical barrier between the shale and wellbore while also filling in any natural fractures.

7. Discussion

Low and medium-temperature geothermal energy resources tend to be more widely distributed than high-temperature ones. Data from geological exploration reveal that hydrocarbon and geothermal resources coexist in sedimentary basins. Deep wells in mature Italian oilfields in sedimentary basins may be good candidate structures for geothermal heat extraction, allowing access to subsurface energy resources.

The concept of repurposing abandoned oil wells into geothermal wells holds significant promise for numerous regions, particularly in countries with high population densities like China and India. The utilization of diverse energy sources is crucial for these nations due to their substantial energy demands.

Despite being one of the leaders in geothermal energy, China still has a lot of untapped potential. This potential is mostly due to the number of abandoned oil wells, which exceeds 76,881. Converting these wells to geothermal energy might be extremely beneficial to the country's energy policy.

In India, the scenario is similar. Being the second most populous country implies a demand for all types of energy. Despite the fact that India possesses 13,348 abandoned oil wells, it uses no geothermal energy. This large number of abandoned oil wells provides a substantial potential for the country. While this approach may not yield substantial electricity generation, it can make a significant contribution to building heating in these countries.

Indonesia, on the other hand, already makes extensive use of geothermal energy. However, given the country's large number of abandoned oil wells (over 20.000), converting these wells into geothermal wells might contribute to Indonesia's ambitious goal of having a geothermal capacity of 5000MW.

Annual geothermal energy growth in America has been lower than average over the previous 30 years. However, America is the leading country in terms of the number of abandoned oil wells, with hundreds of thousands. The extraction of geothermal energy from these wells has the potential to dramatically increase the United States' geothermal energy share.

Brazil is another country with enormous potential, as well as hundreds of abandoned oil wells. However, geothermal energy is used in this country in a minimal amount. Converting abandoned oil wells to geothermal energy can boost geothermal energy extraction not just in Brazil, but also across South America.

On the other hand, the Middle East has massive oil and gas reserves and may be called energy secure. However, reducing Green House Gas emissions should be a top priority for everyone. The Middle East has made significant efforts in recent decades to develop renewable energy sources. However, practically every country in the region utilizes only one sort of energy. When we examine the region's lengthy history of oil production, it is easy to conclude that the region has a substantial number of abandoned oil wells, even though official figures are lacking. Using these abandoned oil wells instead of letting them fall apart might add to the region's renewable energy portfolio while also reducing GHG emissions in the world.

Europe is the region that has made extensive use of geothermal energy. However, thousands of abandoned oil wells may be found in nations such as France, Poland, Romania, and Hungary.

Conversion of these wells may help to accelerate the improvement and adaptation of geothermal energy in the region.

Globally, the total installed capacity for geothermal heating and cooling reached 107.4 GWh. Geothermal heat pumps account for 72% of this capacity, with the remainder coming from direct geothermal heating and cooling.

Offshore decommissioning projects were well-documented and analyzed, however, when we look at onshore decommissioning, there are very few documented instances of projects. This scarcity of examples highlights a critical gap in the existing literature and industry documentation. This absence serves as a reminder of the need for increased attention and research in this domain.

One of the most notable advantages of converting abandoned oil wells is the cost reduction resulting from the elimination or reduction of drilling activities. These wells are primarily repurposed as borehole heat exchangers (BHE). Unlike traditional geothermal wells, BHE technology is not reliant on the hydraulic properties of reservoirs, such as permeability and porosity, which significantly affect traditional geothermal energy extraction. Additionally, it does not necessitate access to an aquifer.

BHEs come in two primary configurations: U-tube and Co-axial. Comparatively, the Co-axial configuration offers a larger heat exchange area, reduced pressure loss, and superior performance.

This thesis reviews three case studies [58][60][61], each involving similar simulations. Despite variations in properties affecting BHE performance, the results consistently validate certain patterns. Sensitivity analyses performed by authors provide a detailed understanding of how changes in flowrate, working fluid, insulation materials, insulation thickness, outer-tubing thickness, well depths, injection temperature, and reverse injection flow impact temperature, power generation, coefficient of performance (COP), and cumulative specific power (CSP).

A comparison of these analyses reveals that they all produced comparable results, which are as follows:

According to results of analysis [58] and [61], a higher flow rate reduces production temperature by shortening the heat exchange period between the working fluid and the surrounding rock, on the other hand, it allows minimal heat loss during upward transport. However, analysis of case study [58] indicates that power generation is also affected by flow rate. Increased flow rate leads to increased power generation. However, this increase is associated with elevated costs, particularly in terms of pump operation. This demonstrates that the optimal flow rate has to be chosen for the system for optimal power generation.

Increased contact surface area can improve heat extraction and overall system performance by increasing outer-tubing diameter. This is the result of both studies of [58] and [60].

Three alternative working fluids, water, ethylene glycol, and diathermic oil, are examined in one of these sensitivity analyses [58]. At the initial stage comparison winner was seen as diathermic oil due to its qualities of slightly reduced heat capacity and double thermal conductivity. However, diathermic oil eventually became the least efficient working fluid. Because heat conductivity has little effect on production temperature, on the other hand, heat capacity, and viscosity are important in power generation. Results of the analysis [60] also show the importance of parameters such as heat capacity, and viscosity.

Analysis related to the insulation material properties has been done by both [58] and [60]. The study [58] compares vacuum-insulated tubing (VIT), polypropylene, and polyethylene. The results revealed that thermal conductivity is a far more relevant criterion than material heat capacity. VIT with lower thermal conductivity emerged as the victor of the comparison; however, given the high installation costs of this material, alternative insulating materials with similar properties but lower costs are viable options.

According to [58], altering insulation thickness had a positive impact on system performance, enhancing temperature, power generation, COP, and CSP. The thicker insulation reduces the available fluid passage volume, potentially limiting the mass flow rate. A similar performance boost was observed when adjusting the outer-well diameter. This improvement was attributed to the increased surface contact area. Nevertheless, it's important to recognize that these enhancements, while informative, may not be practically applicable since large thicknesses are rarely encountered in real-world drilling operations due to economic and technical constraints when reaching hydrocarbon reservoirs.

Varying well depths unveiled a consistent energy relationship across different depths, in the analysis of studies [58] and [61]. The relationship between depth and heat extraction, with respect to temperature, power, COP, and CSP, demonstrated near-linearity. This suggests that energy estimation for various well depths can be approximated as they exhibit a linear dependency. It's essential to acknowledge that these case studies assume a simplified, linear extrapolation of geological conditions to the well's bottom, which may not precisely reflect the actual geological complexity. Nonetheless, deeper geological layers typically feature lower porosity, which positively influences the data accuracy.

When we consider the results of the case study [58], taking into account seasonal temperature fluctuations and injection temperature, the system's efficiency is maximized by maintaining a low injection temperature. Reversing injection flow for cooling purposes is only feasible at low flow rates, resulting in minimal cooling. Therefore, the implementation of a cooling and heating unit at the simulated depths seems impractical. Alternative methods, such as shallower well depths, may offer more efficient cooling options.

In recent times, a groundbreaking technology (Eavor-Loop) has emerged, offering significant advantages over traditional BHEs. Compared to BHEs, Eavor-Loop presents a range of benefits that are poised to revolutionize the field of geothermal energy extraction.

The entire closed-loop nature of Eavor-Loop distinguishes it from conventional geothermal technologies. It functions similarly to a deep radiator or heat exchanger as an underground pipe system. This one-of-a-kind architecture allows for scaling without requiring high-temperature volcanic hotspots, permeable aquifers, or hydrothermal flow capacity. Eavor-Loop is more predictable than Enhanced Geothermal Systems (EGS), which frequently include fracking and induced seismicity. It competes in the markets for district heating, cooling, and dispatchable renewable power, with baseload and load-following features that make it suited for integration with wind and solar energy.

One of the standout features of Eavor-Loop is its application of multilateral wells, a concept that enhances the volume of rock available for heat extraction. In contrast, traditional BHE systems typically employ concentric configurations with approximately 500 meters of wellbore in contact with hot rock. The limitations posed by this approach significantly impact the efficiency and economic feasibility of BHEs. In stark contrast, the commercial Eavor-Loop system stands out with its remarkable 50,000 meters of wellbore in contact with hot rock, all thanks to its pioneering use of multilateral wells. Notably, these multilaterals not only offer heightened efficiency but also cost-effectiveness in drilling. The distribution of costs across multiple energy-mining laterals introduces economies of scale, making this technology increasingly attractive.

Moreover, Eavor-Loop introduces a unique completion method for its horizontal multilateral sections. This method involves the application of a chemical setting agent combined with a tailored working fluid. By doing so, Eavor-Loop streamlines the drilling process, eliminating the need for complex and costly multilateral junctions and casing. The result is a standardized and repeatable approach that not only enhances efficiency but also reduces the overall operational complexity.

While Eavor-Loop is a recently introduced technology and has not been applied to the conversion of abandoned oil wells into geothermal systems, its high potential suggests that it could be adapted for this purpose. Notably, Eavor-Loop also involves two vertical wellbores sealed with casing and cement. This characteristic aligns with the infrastructure of abandoned oil wells, making it conceivable to utilize two closely situated wells for geothermal energy extraction. Such an adaptation has the potential to not only stimulate the process of converting abandoned oil wells into geothermal sources but also significantly increase the share of geothermal energy as a renewable energy source. Furthermore, repurposing deadly and unproductive oil wells into useful, sustainable energy sources can have a positive impact on the environment and the world at large.

8. Conclusion

In conclusion, the concept of turning abandoned oil wells into geothermal wells might be used in every region because geothermal energy can be found anywhere in the Earth's crust and also there are vast numbers of abandoned oil wells almost in all regions, with the exception of Oceania.

Onshore decommissioning examples are few. This lack of onshore instances reveals a crucial gap in existing research and industry documentation. While offshore decommissioning has been the focus of several research and publications, the onshore equivalent remains an understudied and underreported portion of the decommissioning process.

The conversion concept has several advantages, including existing data, less risk, and lower costs. The most significant advantage of this concept is lower drilling costs. For a long time, the expense of drilling has been the principal impediment to the advancement of geothermal energy.

Converting abandoned oil wells into closed-loop systems also saves money and eliminates the need for exploratory wells because this method does not need the presence of an aquifer in the reservoir. Initially, the renovated wells were employed as Borehole Heat Exchangers. When U-tube and Co-axial were compared, the option of Co-axial was shown to be more advantageous.

The parameters for optimizing Co-axial BHEs are discussed. The following results are mentioned:

- The heat capacity of the working fluid has a significant impact on temperature and power output. Reduced heat capacity causes the fluid to rapidly cool from the bottom hole to the surface. The heat capacity of a working fluid is the most significant material attribute.
- In general, as the flow rate increases, the temperature produced drops while the power produced increases. It is crucial to remember that increasing the flow rate often increases operational expenses, owing to the energy consumed by the pump and the increased frequency of pump repair and/or exchange. As a result, economic considerations are critical for proper flow rate optimization in such systems.
- Insulation material is critical for a DCBHE because it reduces cooling during the upward movement. Heat loss is decreased by using the same insulating material and increasing the thickness. Thermal conductivity is the most essential material attribute of an insulating material.
- The energy grows linearly as the depth of the borehole increases.
- A low injection temperature in comparison to the subsurface temperature is critical, as a low injection temperature boosts extraction efficiency.

A review of sensitivity analyses performed by authors revealed that VIT (or a substitute with comparable qualities), water (or glycol for high temperature), and a low injection temperature are critical for constructing an effective BHE. The flow rate is determined by the desired output temperature, which might vary. The increasing thickness of the inner and outer tubes just marginally increases the energy. These are advised if the advantages (energy) outweigh the costs.

Finally, the very recent Eavor-loop technology has great potential, and its application in the process of converting abandoned oil wells for geothermal purposes could stimulate geothermal energy usage and the possibility of generating electricity with this technology even from low and medium geothermal resources could open a new chapter in the conversion process.

One of the energy sector's main goals is to create increasingly advanced tools for exploring the potential transformation of current hydrocarbon sites into geothermal ones. The technological progress should align with the effective implementation of closed-loop technologies, considering the specific geological systems and situations in place. The research sector should focus its future endeavors in this direction.

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