Renewable Energy 194 (2022) 1288–1302

Contents lists available at ScienceDirect

Renewable Energy

journal homepage: www.elsevier.com/locate/renene

Repurposing abandoned wells for geothermal energy: Current status and future prospects

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ARTICLE INFO

Article history:
Received 9 December 2021
Received in revised form
19 April 2022
Accepted 26 May 2022
Available online 1 June 2022

Keywords:
Abandoned wells
Geothermal energy
Green energy
Well integrity
Heat extraction

ABSTRACT

A debate rages as to whether abandoned oil and gas wells have to be sealed to prevent methane leakage – a potent greenhouse gas – or whether the valuable infrastructure can be repurposed for environmental benefit. One viable solution is to repurpose such wells for the recovery of low-grade geothermal energy and simultaneously produce a revenue stream, staunch fugitive emissions and maintain workforce engagement. This avoids the major upfront costs of drilling and significant risks of non-transmissive reservoirs that remain major obstacles in the development of geothermal energy. Regions of extensive hydrocarbon exploration are often close to market and with significant geothermal gradients. Repurposing must accommodate local energy demand, potential markets, existing infrastructure and technical challenges. So far, most studies have been scattered or focused on the viability of converting a specific oilfield. This work integrates the accomplishments and key challenges faced from projects that converted hydrocarbon production in geothermal renewable energy and establish guidelines to assist future projects. Conversion strategies are discussed for open-loop systems with co-production and enhanced geothermal systems and for true closed-loop systems. Five key challenges relate to well selection, data availability, underground infrastructure, well integrity and regulatory factors. Potential challenges in inspection and preparation of these wells in terms of well integrity and productivity with possible remedies are also discussed. Pilot projects and feasibility studies that have been performed worldwide confirm the viability of this concept but at low efficiency, paving the way for future innovations in this area.

1. Introduction

The decarbonization of communities and their energy supply is considered as a contemporary priority path forward, although it poses many challenges. As more countries become industrialized and population growth continues, energy consumption will continue to increase [1,2]. Many countries have already committed to reducing or even achieving net-zero carbon emissions by 2050 [3,4], however, significant upfront costs have been realized as a major obstacle for developing different renewable energy sources, including geothermal energy. For geothermal energy, a large portion of the implementation cost comes from drilling. Thus, research efforts to repurpose oil and gas wells to geothermal wells are increasing [5,6]. The idea has had agency for quite some time, but so far only a few pilot projects have been successful, mostly small scale power generation from co-produced fluids [7–10]. Previous works focused on technical feasibility of repurposing wells [11–13], risk assessment [6,14], or evaluating economical and regulatory factors [5,15]. The following reviews the current state of practice in repurposing oil and gas wells, analyzes their successes and failures and discusses what is needed for future development.

Currently, most of the world's energy production is from oil and gas resources. After cessation of oil and gas production, both wells and well site should be returned to a condition as close as possible to the original in order for the well to be permanently abandoned. The abandonment process is both costly and complex, involving cement plugs placed at predetermined depths to completely seal the wellbore and ensure no communication between different zones. Currently, a large number of wells are being abandoned offshore in both the North Sea [16] and the Gulf of Mexico [17]. Added to this, the increase in exploration of unconventional wells in shale reservoirs within the last decade, which have shorter production lifespans and require a larger number of wells to be

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https://doi.org/10.1016/j.renene.2022.05.138

Abbreviations

GHG	Greenhouse gas
IEA	International Energy Agency
DOE	Department of Energy
EGS	Enhanced Geothermal Systems
ENAA	Engineering Advancement Association
FORGE	Frontier Observatory for Research in Geothermal Energy
NEPA	National Environmental Policy Act
NCG	Non-condensable gas
BHE	Borehole exchanger
DHX	Downhole heat exchanger
ORC	Organic Rankine Cycle
P&A	Plugging and abandonment
PICHTR	Pacific International Center for High Technology Research
RMOTC	Rocky Mountain Oilfield Testing Center
ºC	Degree Celsius
m	Meter
km	Kilometer
m^3	Cubic meter
kW	Kilowatt
MW	Megawatt
kWe	Kilowatt of electrical power
MWt	Megawatt thermal
h	Hour
kg	Kilogram
MPa	Mega Pascal

drilled, it is expected that many of these will soon reach maturity and then require abandonment. These are usually long reach (up to ~5 km) horizontal wells with a higher probability of leakage [18]. These wells can also be a source of unwanted and uncontrolled methane emissions. Methane is a potent greenhouse gas, up to 86 times more powerful in warming the climate than CO_2, in the short term. It can remain in the atmosphere for 12 years but is a major precursor for tropospheric ozone, harmful to human health and plant growth.

Typically, well decommissioning brings no financial return and only a net burden (except for some scrap metals) to the operator. In the long term, the well may deteriorate and loss of integrity can result in methane leakage to the atmosphere [18] as well as the contamination of aquifers [19]. Unfortunately, in the past when regulations were particularly lenient and thus inadequate, many oil and gas wells were left unplugged, especially by small operators [20]. Nevertheless, even when plugged, there was little emphasis placed on ensuring that wells were properly sealed due to a lack of benchmarks and limited standardization. When wells are improperly plugged, they can be potential methane emitters. In recent years, operators have begun to pay more attention to proper plugging of these wells due to increasing environmental awareness, safety considerations, and more strict regulations [21]. In addition, increased negative attention from the media has heightened public interest in well abandonment. While it is vital to raise awareness, the technological difficulties and operational constraints associated with plugging and abandonment remain.

The USA federal government is currently planning to invest $16 billion to plug a limited number of abandoned wells [22]. While it is undeniable that the investment can generate thousands of jobs and reduce environmental risks, many ventures are evaluating whether repurposing wells in other ways may be a viable solution to make use of the valuable infrastructure [23]. Carbon capture and sequestration projects have emerged as a potential candidate for re-purposing oil and gas wells [24,25], but these projects still involve a significant uncertainty in the CO_2 behavior in the long term and require perfect sealing and integrity which is often not the case in abandoned wells. Repurposing abandoned wells to uses related to geothermal energy has been explored but the low temperature of the oil and gas reservoirs (in comparison with geothermal) often limited further development. Recent advancements and increased efficiency in low-temperature power conversion methods have raised some interest in low-temperature geothermal production and has generated many projects attempting to repurpose oil and gas wells.

1.1. Geothermal energy

Geothermal energy is a ubiquitous renewable resource that has been used for power generation in more than twenty countries since the beginning of the 20th century. In comparison to other resources, geothermal energy is an almost inexhaustible resource. Thus, depletion is not a concern, and its availability is much higher than for other renewable energy sources [6]. Geothermal energy can contribute to future energy systems by supplying 3.5% of the worldwide power generation share and 3.9% of the heat generation share by the mid of this century, according to the IEA [26].

The geothermal resources that are most often utilized are at high temperatures (above 180 °C) where wells around 1000–2000 m deep are drilled into hot aquifers to produce steam or a combination of steam and water [27]. These resources are limited to areas of high thermal gradients at tectonic-plate boundaries where high permeability is ubiquitous as a result of tectonic deformations. Such hydrothermal high-temperature resources at accessible depths have already been explored. They are limited both in extent and geographic location. Conversely, oil and gas wells produce from lower temperature formations, so naturally, the next step in the development of geothermal energy would be exploring lower temperature systems, with water production ranging from temperatures between 120 and 150 °C. Even lower temperature wells have the potential to reduce carbon footprint, not only by generating electricity but by directly serving as a source of heating residences, green-houses and farms, hospitals and for other purposes. A modified Lindall Diagram illustrates the variety of potential utilizations of a geothermal resource based on temperature (Fig. 1).

Recently, the general interest in geothermal energy has increased, but this field always faced technical and market barriers and the lack of public awareness [28]. The U.S. has experienced a stagnation in geothermal power capacity and decrease in geothermal power generation from 1990 to 2018. About 44% of US geothermal plants are more than 30 years old, representing 64% of the total geothermal capacity [29]. During the 1980's, geothermal development was boosted for heat generation due to high prices of competing heat sources (oil and gas). High temperature of the formation by itself does not guarantee a successful geothermal project. As observed in California, where there is favorable geothermal gradient and rising demand for renewable energy, geothermal power generation is declining, mainly because of natural well degradation and the failure of new geothermal projects [30]. Geothermal exploration can be very challenging as it involves uncertainties in both the flow rate and temperature of produced

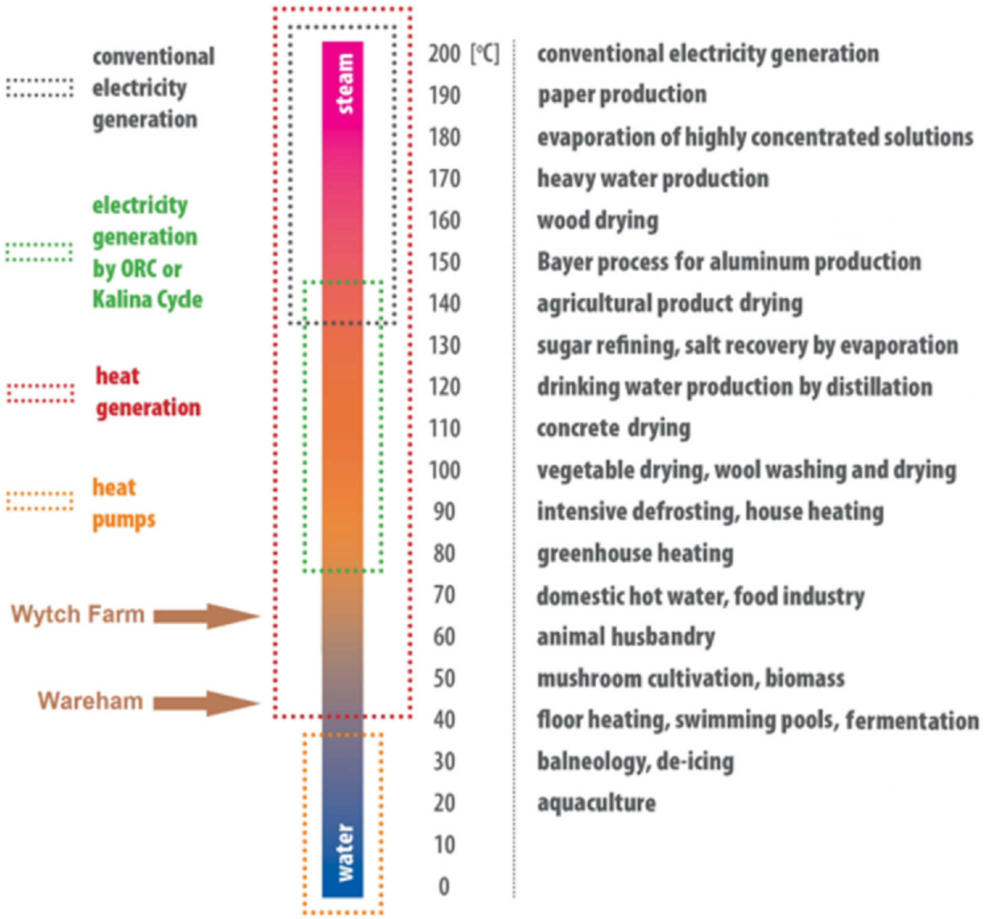


Fig. 1. Modified Lindall Diagram showing a range of well-established applications for geothermal energy at different temperatures [16].

fluids; as recently seen in the Baturraden geothermal project in Indonesia [31], two wells were drilled into high temperature zones but produced insufficient fluids output. A study commissioned by the World Bank concluded that approximately 22% of all geothermal wells worldwide have failed [27], with most of the failure occurring during the drilling stage (Fig. 2). Repurposing hydrocarbon wells are advantageous in this aspect because the wells are already drilled, the downhole conditions are well known, and they are extremely abundant. The main issue, until recently, was the low-temperature of the resources situated in sedimentary basins, but this has changed with the advent of binary power generation.

1.2. Low-temperature geothermal generation

Low temperature geothermal resources (between 100 and 150 °C) are plentiful and can be explored in most locations worldwide; however, they are mostly used for direct and indirect heating [32]. To generate power from low-temperature heat-transfer fluids, closed binary Organic Rankine Cycle (ORC) has proved to be a feasible option. ORC technology is a state-of-the-art system where low enthalpy organic fluids (working fluids typically, isobutane, isopentane, R-134a, and ammonia) with low boiling temperatures relative to water, are vaporized by the recovered well water to generate energy. The working fluid is heated in a closed

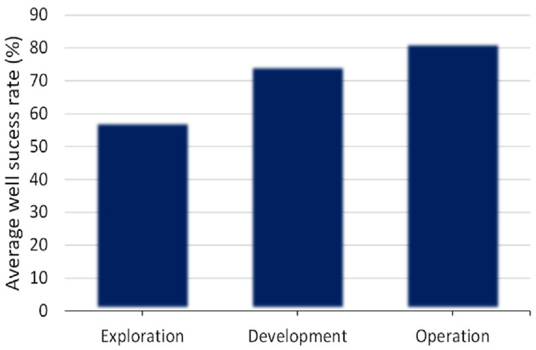


Fig. 2. Success rate for geothermal projects by project phase [18].

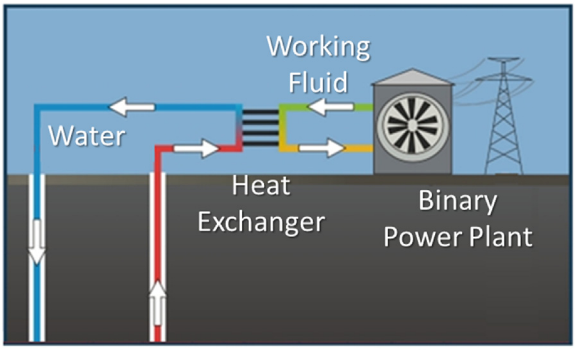


Fig. 3. Simplified schematic of ORC for low temperature power generation.

system through a heat exchanger by the water recovered from the well (Fig. 3). Thus, ORC plants are environmentally friendly with little to no emissions of atmospheric pollutants — such as CO, CO_2, NO_X, and SO_X. The most important feature of this system is its capability to utilize low-temperature geothermal sources for power generation. The drawback is its relatively low efficiency as compared to other systems [33].

ORC systems use organic fluids because they have lower critical temperature (and consequently lower boiling temperature) than water. However, compared to water, the higher molecular weight of organic fluids allows for smaller turbine designs, with greater mass flow and higher efficiency (~80%–85%) [34]. Significant research efforts on ORC systems have been conducted. Nevertheless, selecting the proper working fluid and the specific cycle design remain one of the main challenges [35]. Researchers have employed several different fluids as organic working fluids to test the ORC system, as well as their thermodynamic properties [33,36]. In these developments, conventionally, a single fluid is tested as a working fluid; however, mixing two or more working fluids has resulted in more efficient ORC systems. The mixture of fluids, owing to a non-isothermal phase change, results in a better agreement with the thermal profiles of the ORC and the heat sink or source during phase changes, [37]. An essential aspect of the selection of the working fluid is the temperature of the target heat source [11]. The working fluid also has to satisfy the safety criteria, lower the costs in the power plant and be environmentally friendly.

The cycle design process optimizes the thermal efficiency and use of the available heat source. However, to improve the work output, the most significant results are limited to the choice of working fluids that corresponds to the current heat source and sink temperatures [38]. Low-temperature geothermal generation, in the early 2000s, could only reach six percent of efficiency for conversion of heat to electrical energy, with most ORC units intended to generate 50–250 kW [9]. However, they have improved significantly with recent modifications. Tartière and Astolfi [39] compiled data from 27 manufacturers and more than 700 projects to create a database of ORC plants and analyze the evolution of the system.

By using water as a circulating fluid in the wellbore, the organic working fluid remains contained in a closed system on the surface; presenting economic and environmental advantages over acquiring and safe storage of substantial volumes of organic fluids in the subsurface [40]. However, a few investigations have explored the use of organic fluids for circulation in abandoned oil wells for geothermal power generation, such as isobutane [41] and R125 [42].

Another option to generate power from low temperature geothermal systems is through the Kalina Cycle (KC) [43]. The KC is essentially a modified Rankine cycle in which the working fluid is a mixture of two distinct compounds: water and ammonia. When compared to the traditional Rankine cycle, the exergy efficiency might increase by 10%–20% [44]. The presence of ammonia in the working fluid has the effect of increasing thermodynamic reversibility. As the thermodynamic reversibility increases and the irreversibility decreases, higher thermodynamic efficiencies can be achieved. Several studies reported its superior efficiency over ORC [44,45]. However, as with any new technologies, difficulties with machinery and lesser operational security or uptime have posed challenges in implementation. The Husavik geothermal power plant in Iceland was the first to install the KC in 2000. From the beginning it was beset by issues, many of which were related to corrosion of the turbine and nozzle vanes, causing the plant to shut down regularly and run at much lower efficiency (lower power generation) than the one promised by design [46]. This technology is still maturing, and two new KC power plants have been built in Germany with power outputs of 3.4 MW and 580 kW [47]. Feasibility studies, motivated by the recent success, reported economic benefits of using the KC in hydrocarbon wells for geothermal generation [48].

Other than binary cycles, thermoelectric power generation can be harvested from low-temperature sources. Thermoelectric transformation materials, as one totally solid-state energy conversion technology, can directly convert thermal energy into electricity. There are no moving components in a thermoelectric power converter. Furthermore, it is small, quiet, dependable, and ecologically beneficial. As a result, the entire system can be simplified and operated for a long time with minimal maintenance [49]. Further research and development is required since the efficiency is very low (<10%) and installation costs are still very high [50].

1.3. Economical aspects

The global market for the geothermal energy has been increasing at the rate of 10.9% annually, mainly driven by policies incentivize renewable energy sources [51]. More than 20 countries in the world use geothermal steam to generate electricity, but North America was the largest region in the geothermal electric power generation market in 2018, accounting for 37.7% of the total global market share [51]. Countries such as the USA and Mexico have large geothermal reserves and availability of advanced technologies to harness geothermal energy, as well as subsidies and incentives that allow an expansion of geothermally produced supply into the market at reasonable prices.

To explore geothermal resources, the main costs are upfront costs for drilling, completions and surface equipment (heat pump or power plant). The high costs of drilling geothermal wells have restricted further developments of the geothermal resources as it draws 42%–95% of the total project costs [52]. As the operating drilling time may vary, the resulting cost of individual wells fluctuates, accordingly. It takes about 45 days to drill a geothermal well, however this figure may vary from 25 to over 100 days. Inexpensive wells may cost as little as $1 M, while expensive wells may cost over $15M. An average well-cost estimate probably would be in the range of $4M to $6M. These estimates are in agreement with the geothermal drilling campaign reported in Nevada [53]. Inexpensive wells usually correspond to shallow resources located in sedimentary basins. In contrast, expensive wells are usually characterized by deep reservoirs located in hard rock formations with corrosive brine or under high pressure at temperatures above 200 °C.

In low temperature geothermal wells, additional costs for ORC equipment needs to be considered, which may significantly increase the initial investment compared to high temperature geothermal resources. Besides heat, high enough flow rates are also needed to generate electricity at meaningful rates, thus having multiple wells require in these projects. Repurposing an abandoned well is viewed as more a feasible alternative to develop a low temperature geothermal field. Table 1 details the costs involved in the project.

Assuming 95% uptime for the power plant equates in an average electricity production of 118,260 MW h/year. By utilizing repurposed oil and gas wells, the levelized cost electricity generation drops in 11%. Hence, converting mature or abandoned oil or gas wells to generate geothermal electricity is a potential way to reduce initial investment costs. Since the wells, pipelines, surface production systems, and other infrastructures in the depleted oil and gas fields already exist in the project area, there will also be a minimal additional footprint on the environment for the geothermal production.

Table 1
Geothermal electricity production estimate summary.

	Geothermal Field	Repurposed Hydrocarbon Field
Total costs (USD M$)	116	83
Drilling wells	21.7	–
Plant site development	5.8	–
Well site development	0.67	–
Well pumps	10.5	10.5
Piping to central facility	7.2	–
Reconditioning wells	–	15
ORC Equipment	40	40
Electrical grid connection	12	12
Permitting and fees	13	5
Capacity (MW)	15	12
Average annual electricity production (GWh/year)	118	95
Levelized Cost ($/kWh)	0.98	0.87

2. Geothermal heat harvesting methods

Several pilot projects repurposing oil and gas wells for geothermal extraction have been completed and others are in an advanced stage. Here we review them individually by separating them into two categories: open-loop systems (coproduction and enhanced geothermal system) and closed-loop systems.

2.1. Open loop system

In an open-loop geothermal power generation system, the well is connected directly to the groundwater resource. Usually, two or more wells are employed, at least one well for production and another one for reinjection. The main challenge in these arrangements is pressure decline of the reservoir over time and the simultaneous production of hydrocarbon fluids with hot water that requires extra treatment to conform to environmental standards. In the following, we discuss these issues in more details.

2.1.1. Coproduction

A coproduction geothermal system is a geothermal system that employs fluids that are produced along with oil or gas. Many wells are abandoned each year upon reaching maturity as a large volume of water is produced instead of hydrocarbons. The costs of managing the co-produced water are high, as it needs to be treated before being released into the environment. The produced water might also source from water flooding applications - an operation to counter pressure decline in the reservoir. The US's annual production of hot water from oil and gas wells in the is anticipated to be about 4 billion m^3 [54]. Binary power generation units can now take this water and use its thermal energy to produce power. Today, the oil and gas industry have an inventory of thousands of wells, with previous information about flow rate and temperature, capable of generating GHG emission-free power. In the US, around 823,000 wells are producing hot water along with oil and gas [54].

Pilot projects have successfully generated power using coproduced fluids during oil and gas production in the US, China and Colombia. The first pilot demonstration by the US Department of Energy started in 2008 and at the Rocky Mountain Oilfield Testing Center located in Wyoming, USA. The location is advantageous due to many producing oil wells that are linked to a central facility for fluids separation. The demonstration lasted 4.5 months and employed an air-cooled ORC [7,55]. In 3.5 years of operation (second phase), the ORC power unit used co-produced water at 90.6–98.9 °C, at a rate of 6350 m^3/day, and produced 180 kW of electricity (net power generation of 132 kW) [56]. The main challenges of the project included a lack of availability of clean water and an extremely cold winter (−35 °C), which led to frequent shutdowns of the wells for maintenance. Additionally, such conditions complicate the functioning of surface facilities.

A six-month pilot test was also conducted at Denbury's Laurel Oilfield in Mississippi, generating power from coproduced fluids [8]. The well produced at a depth of 2900m using an electric submersible pump, producing 16m^3/day of oil and 636 m^3/day of water, corresponding to 98% water, at low temperature (95 °C) and flow (648m^3/day). The ORC unit used R245FA fluid and produced an average of 19kWe of power and a maximum of 22kWe.One of the most significant challenges in the project was the high ambient temperature, although the power generated was sufficient to offset ~20% of the electric submersible pump (ESP) power requirements [8].

In China, there was an effort in 2011 to build a low temperature geothermal plant employing coproduced resources from the Huabei Oilfield [10]. The geothermal plant, a water-cooled screw expander unit that used R123 as the working fluid, generated 310 kWe utilizing co-produced water from eight production wells at 33 kg/s and 110 °C. This project pioneered low temperature geothermal power generation from coproduced water in China. It also confirmed feasibility and test production rates, lifting ability of ESP, and water reinjection [10]. Upon conclusion, the project was expanded using power generators with greater capacity.

In 2016, the University of North Dakota managed to generate power from co-produced water from a gas well in the Williston Sedimentary Basin [57]. Two 8-inch diameter open-hole horizontal wells at depths of 2300 m and 2400 m with lateral extensions of 1,290 m and 860 m produced water at a combined flow rate of 4400 m^3/day. In addition, two water supply wells 570 m and 340 m away from the power plant supplied water through uninsulated pipes buried beneath the frost line. The water temperature was 103 °C at the wellheads and 98 °C at the ORC inlet. Power production potential with the existing resource was estimated to be ~350 kW [57]. Although it operated for only two days due to frost damage, the project demonstrated that generating electricity from unconventional, low-temperature geothermal resources is technically and economically viable using binary technology.

More recently, in Colombia, a small-scale pilot demonstration generated 100 kW from co-produced fluids at the Las Maracas field in Casanare. The operator, a joint industry between Parex Resources and Universidad Nacional de Colombia, observed high temperature gradients, permeable rocks, and freshwater produced to the surface without additional costs during oil production. For oil production, usually, pumps and facilities use electricity from diesel and natural gas generators that run continuously. Therefore, utilizing hot water produced from their own wells to generate power is very beneficial for the operators [58,59]. Table 2 summarizes these previously described pilot projects.

Table 2
Geothermal power generation projects from co-produced fluids.

Year	Operator	Location	Power Output (kW)	Source
2008	US Department of Energy	RMOTC Wyoming - USA	180	Reinhardt et al. [7]
2011	ElectraTherm	Laurel Oilfield -Mississippi - USA	50	ElectraTherm [8]
2011	PetroChina	Huabei Oilfield - China	310	Xin et al. [10]
2016	University of North Dakota	Williston Basin- USA	124	Gosnold [57]
2021	Parex Resources and Universidad Nacional de Colombia-Medellin	Las Maracas - Colombia	100	Parex Resources Inc [58]

Similar to these projects, there are likely thousands of existing wells that could be generating emission-free power, where the temperatures and flow rates are already known. Co-production systems offer a low-risk solution, but the power generation potential is also relatively low. To be competitive with electricity prices, a co-production well in the US needs to produce about 662 m^3/h at 150 °C [15]. Additionally, power generation employing co-produced water may be potentially hazardous to the power generator performance and the economic attractiveness. First, the properties of the co-produced water — temperature, rate and composition — can undergo variations during production. If co-produced water provides insufficient heat, power generation dynamics may be dramatically affected. For example, a pilot project in Texas failed because it could not achieve constant flow rates and stable wellhead temperature [60]. Secondly, if not treated, coproduced water might cause scaling and corrosion issues for surface equipment, increasing maintenance costs and decreasing the efficiency of heat exchangers, leading to reduction of power output and economic competitiveness [6].

2.1.2. Enhanced geothermal systems (EGS)

An Enhanced/Engineered Geothermal System (EGS) comprises an artificially created reservoir with abundant heat but absent of natural permeability or fluid saturation. It originated from the exploration of Hot Dry Rock (HDR) systems at Los Alamos National Laboratory in 1974. It was later reproduced in the UK and Japan, continuing since 1987 at Soultz-sous-Forêts, France [61]. The EGS process lies in establishing a subsurface fracture system that can continuously circulate water between injection wells and production wells for heat extraction. Developing an EGS requires increasing the natural permeability of the rock. First, the water is injected through injection wells to the induced fractures and heated by contact with the rock. Then, as in naturally occurring hydrothermal systems, water is produced via production wells (Fig. 4). EGS are man-made reservoirs created to overcome the limitations of the thermal resource where inadequate water and/or permeability is present.

In comparison with other geothermal energy ventures, EGS reservoirs are advantageous due to the access to more abundant heat after the creation of human-made fractures in the hot subsurface and fluid injection into them [62]. The greatest challenge lies in the uncertainties related to the artificially created geothermal reservoir in ensuring its productivity and longevity — currently the focus of current research and studies. The development of the technology needed to transform EGS into a large-scale energy supply of the future is a critical challenge that offers significant rewards — an almost inexhaustible thermal resource [63]. The costs associated with drilling, completion and hydraulic EGS wells is extremely high (around $10 million/well), hence why converting abandoned unconventional hydrocarbon wells with multi-stage fracturing completions has been considered as an option to explore EGS reservoirs. The cost of the injecting and producing working fluid should correspond to the geothermal energy required to amortize the capital costs. To sustain high-temperature fluid production, fluid injection is essential because wells in non-hydrothermal areas usually produce insufficient native fluids. To optimize performance, different injection-production patterns need to be tested [64].

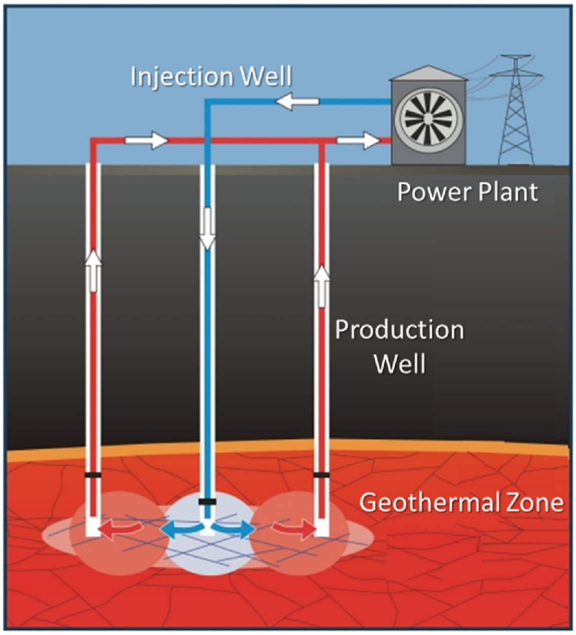


Fig. 4. Simplified Schematic of EGS with three wells. A subsurface fracture system increases the permeability of the system and connects injection and production wells.

Although the EGS concept is not new, successful long-lived implementation remains elusive. The first test was performed in New Mexico in 1974 [65] with two wells - one productor and one injector - and a series of hydraulic fracturing stages. The wells were ~3000m deep and recovered 4 MWt of thermal power. Several pilot projects followed in Japan, Australia, and Switzerland but were generally short-lived and unsuccessful [63]. They were terminated due to failure to reach the projected capacity, lost circulation, induced seismic activity or failure to reach economic thresholds [62]. Currently, only one large-scale EGS project exists at Soultz, France [66]. The construction required installation of 15 km of pipeline, estimated at $17 million, and its commercial success has yet to be proven [12],

In 2019, the Caldwell Ranch Exploration Project confirmed an initial 11.4 MW potential of power generation capacity through a demonstration involving a previously abandoned geothermal system at the Geysers geothermal field in California [67]. The project involved three wells, of which two were deepened, recompleted, and used as injector and producer. The third well was used for the recovery of injection-derived steam. Fig. 5 describes the completion schedule for one of the wells that was deepened below 1000m to better access the high temperature reservoir (HTR). The deepened parts of the well needed to be protected with regular or slotted liners based on the temperature in each zone. These wells were drilled in the 1980s but were never produced due to elevated

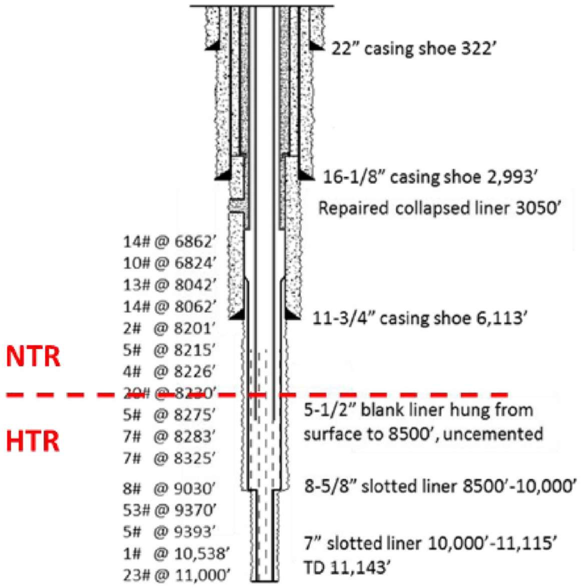


Fig. 5. Completion schematics of the well that deepened and recompleted to go beyond the normal temperature reservoir (NTR) and reach the high temperature reservoir (HTR) [55].

concentrations of non-condensable gases (NCG). For this project to be feasible, the NCG concentrations were diluted through injection-derived steam. Another accomplished goal of the demonstration was the stimulation of permeability in the high-temperature reservoir by fracture reactivation by injecting water at a low flow rate ($\leq$5450 m^3/day), relatively low temperature and low pressures ($\leq$10 MPa) into a very hot rock. The US Department of Energy is currently developing a large-scale Frontier Observatory for Research in Geothermal Energy (FORGE) in Utah to develop, test, and optimize EGS technologies [68,69]. Highly deviated wells, more than 3000 m long, will penetrate hot, hard crystalline granite that will, then, be fractured. The project has evolved through a long concept testing phase and currently is in the drilling stage.

The cost of these EGS projects has been extremely high, requiring massive volumes of working fluid and drilling and completion in extremely challenging and, heretofore, uncharted environments. While new design solutions continue to be studied to improve the viability of such projects, repurposing oil and gas wells offers an attractive solution where wells are already hydraulically fractured. To date, no full-scale EGS project from abandoned oil and gas wells has been implemented. A feasibility study to repurpose oil and gas wells with extensive fracture systems in West Virginia came to the conclusion that the project was not going to competitive with US electricity prices (at that time), even if only for district heating [70]. In order to be competitive, EGS development from oil and gas wells should reduce financial risk by proving reliable reservoir performance and be close to the end-user [15]. The geothermal potential in oil and gas reservoirs is well evaluated in some regions and fields, such as Texas [71] and in the Illinois and Michigan basins in the US [72] and in the and Bohai Bay basin and Daqing oilfield in China [73]. However, there remain many areas and oilfields worldwide where the geothermal potential remains to be systematically and comprehensively assessed [74].

Similar to co-production systems, the produced water can contain high levels of sulfur, salt, and radioactive elements. These are prejudicial to heat exchangers, reducing their efficiency by causing scaling and corrosion issues, and increasing maintenance costs. Therefore, extracted water should be reinjected into the reservoir - a costly process. Land subsidence is another potential drawback in open-loop systems, even with re-injection. Most open-loop facilities address this issue of reservoir pressure decline with reinjection of the working fluid into the reservoir; however, this solution can induce significant seismic events. For instance, induced earthquakes in an open-loop geothermal reservoir in Basel (2004), Switzerland, led to the termination of the entire project as it did in Pohang (2017), Korea. A significant part of all geothermal wells worldwide fail due to poor brine production, the presence of high concentrations of non-condensable gases (NCGs), low wellhead pressures, corrosive brines, and insufficient permeability [27]. Remedial work often involves additional drilling with high costs and risks.

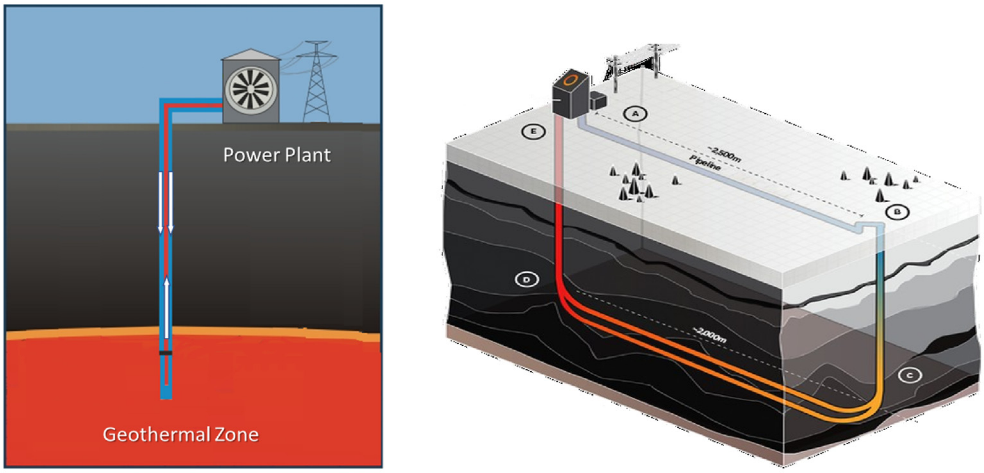
Alternative concepts include in situ combustion to increase the reservoir temperature [75–77]. In situ combustion is an enhanced oil recovery method that facilitates heavy oil production by generating heat and decreasing oil viscosity. In these studies, air is pumped into the reservoir to oxidize the remaining hydrocarbons present and increase the pressure. The combustion of hydrocarbons generates heat, which is sustained by air or oxygen injection into the formation [75].

2.2. Closed-loop systems

In a closed-loop system (Fig. 6a), fluid continuously circulates through a single well in a closed-circuit through a coaxial borehole hole exchanger (BHE) or down-hole heat exchanger (DHX). The BHE consists of an insulated tubing introduced in the well with an open end at the bottom, allowing production. Shallow BHEs are widely used as a reliable source for heating. More than 20,000 plants are operating in Switzerland alone, with well depths between 50 and 350m [78]. However, for deeper projects, drilling costs can be prohibitive. Currently, the two most commonly implemented BHE types are the U-tube and the double-pipe. U-tube heat exchangers are installed in the wellbore before infilling the remaining wellbore annulus with grouting material to enhance the thermal conductivity of the soil, thereby improving heat transfer from formation to the wellbore. In the double pipe system, the tubing works as the inner pipe and the casing as the outer pipe. Therefore, the pipe comprises an insulating material, such as polyethylene or polystyrene [79]. Compared to double pipe heat exchangers, U-tube heat exchangers have a smaller surface area to exchange heat and allow a lower volume of working fluid. The U-tube heat exchanger is commonly used in the shallow subsurface for space cooling and heating. Recently, emphasis has shifted to the use of double pipe configurations due to higher heat exchange efficiency of the system, which saves pumping energy and do not require grout to infill the annulus. In addition, closed loops make it possible to use water and alternative heat-transfer/transport fluids such as supercritical CO_2, creating a strong thermosiphon effect that eliminates both the need for an external pump and associated parasitic energy consumption [80].

Deep BHEs were first proved feasible in Japan in 1991 by a joint project between the Engineering Advancement Association (ENAA) and the Pacific International Center for High Technology Research (PICHTR) [81]. The experiment was conducted successfully in the 876.5m deep HGP-A well in Hawaii, where the bottomhole temperature was 110 °C. During the experiment, the produced water achieved 98 °C at the highest, with the net thermal outputs of 370 kW, and maximum gross output of 540 kW.

Switzerland tested two deep BHE plants: one at Weissbad, with a 1600m deep borehole, started operations in 1996 [82], and one at Weggis, with a 2300m deep borehole, started in 1994 [83]. However, neither of these projects was originally intended to be a closed-loop system. Due to the low permeability of the formations, the operator later decided to install deep BHEs. In the Weissbad



(a) (b)

Fig. 6. a)A simplified schematic of a closed-loop geothermal system for power generation; b) A U-tube shaped closed-loop system currently in development in Alberta, Canada.

well, the output temperatures were significantly lower than expected, and the cause is believed to be cement debonding from the casing. In 2004, a 2500 m well was drilled with the intent to install a deep BHE to use geothermal energy for heating and cooling part of the campus of RWTH-Aachen. However, the university decided not to complete the project due to excessive costs of the insulated tubing [84]. In 2014 a field trial was run in an existing 2600 m well in Cornwall, England, by Geon Energy Ltd. The well was originally drilled in 1980 as part of the Camborne Hot Dry Rock project. A 2000m BHE was inserted along with a fiber optic cable to monitor the temperature. The results demonstrated that, if managed properly, the system could generate ~400 kW with a 7 kW electrical pumping loss [85]. After the success of the demonstration, several other projects were developed.

In 2020, GreenFire Energy Inc. performed the first field-scale piloting of a BHE at Coso Geothermal Field, California [80]. The demonstration was completed at a previously abandoned geothermal well that was producing NCGs. Although the well was more than 1000 m deep, the installed BHE was only 330m long due to budget constraints. Various production rates were tested with a low flow rate producing ~1 MW electrical power of steam equivalent, but the value could increase to >1.2 MW for an optimized configuration. Besides water, the system was tested with supercritical CO_2 as a working fluid [86]. The circulation was performed without pumping, utilizing the thermosiphon effect. In this process, cold (and dense) CO_2 flows through an insulated pipe to the bottom of the BHE as driven by gravity and the heated fluid then buoys to the surface. In this configuration, the power production was low and confirmed that the thermosiphon requires extensive wells to accumulate pressure and produce 1–2 MW of electricity. Therefore, power capacity is expected to increase with a longer well.

Finally, in 2021 the very first closed-loop geothermal well was successfully converted from an abandoned oil well in Hungary by MS Energy Solutions. The company produced 0.5 MWt of heat from a deep wellbore drilled in the 1960s at Kiskunhalas, Hungary. Demonstration projects in the USA [87,88] and Slovenia [89] are in the advanced stages of implementation and may begin tests soon.

The principal limitation of closed-loop systems is that heat is extracted solely by conduction, and conduction absent convection intrinsically limits the heat recovery rate to the relatively small heat-transfer area of the wellbore [90]. Thus, the heat recovery rate and the power generated are typically very low and may not justify the investment. Repurposing long horizontal wells can be a solution due to increased contact area but still needs further evaluation. For example, a project located near Sylvan Lake, Alberta, Canada, by Eavor Technologies consists of 2.5 km long purpose-drilled multilateral horizontal wellbores. They connect two 2.4 km deep vertical wellbores to create a U-tube shaped closed-loop system (Fig. 6b). A magnetic ranging technology was applied to connect the two horizontal wellbores, which were sealed with a novel completion technique. The result is a large subsurface heat exchanger. Then, water is circulated through the system, driven by the thermosiphon effect created by the density difference between the inlet and outlet wells. The company has already announced that it will start working on a similar project in Geretsried, Germany [91]. The results, if positive, may be key to confirm the feasibility of repurposing horizontal wells for geothermal energy.

A suggestion to overcome the heat extraction limitation is the use of thermally conductive fractures [92,93]. In their studies, the well was fractured in different stages. Instead of producing hot water from them, these fractures are propped with high thermal conductivity materials such as high conductivity slurry and metallic grains as proppants. This way, the contact area between the casing and the formation increases by orders of magnitude to compensate for the lack of forced convection [93]. A similar concept is being developed by Sage Geosystems, exploring the propagation of fractures downward to reach higher bottomhole temperatures [94]. The fractures are later filled with high conductive slurry and working fluid is circulated through a BHE taking advantage of the highly conductive fracture network. Another way of increasing heat extraction is by improving the thermal properties of the working fluid through the use of nanoparticles [95–97]. Such combinations of nanoparticles in fluids (called nanofluids) have been widely investigated and demonstrated significant increases in the thermal properties of fluids with minimal concentrations of nanoparticles. These studies explored the effects of using CuO-water, Al_2O_3-water nanofluids, and graphite nanoplatelets on the performance of geothermal BHE.

Numerous studies have analyzed closed-loop geothermal energy extraction systems using abandoned oil and gas wells. These studies are primarily focused on the viability of repurposing abandoned oil wells for geothermal energy extraction and in verifying long-term production capacity [13,41,98–100]. A search through the Geothermal Resources Council e-Library or the

Stanford online collection search engine displays an increase of works focused on this topic in recent years. These studies establish various numerical models to quantify heat extraction and analyzed case studies of known reservoirs to define the geothermal potential of various abandoned well configurations. Although each well is unique, the main factors affecting the results include circulating fluid temperature, injection rate, fluid selection, insulation type, and formation temperature.

3. Repurposing challenges

Although efforts to repurpose abandoned hydrocarbon wells into geothermal resources have increased, many challenges remain, restricting further development of this concept. Ubiquitous challenges are low energy conversion efficiency, improper planning and assessment, regulation and law, and well integrity issues. However, due to the very early nature of the concept, there is ample opportunity for improvement.

3.1. Well selection

The selection of existing hydrocarbon wells for repurposing as geothermal wells is highly dependent on the geothermal gradient but additionally, and in some cases more importantly, dependent on the proximity of end users. Most wells are situated in rural areas with low residential densities where heating and energy demands are low [6]. Long distances for power transfer and especially fluids may increase the operational costs, resulting in a less cost-effective utilization. In addition, the power must first be sold to a utility company which then will sell the power to the end-user. Depending on the location and the utility company, a purchase agreement could be either straightforward (such as a utility distributed generation program) or complex (such as a long-term power purchase agreement) and will therefore significantly affect the economics of the project [56]. On the other hand, a remote location can be utilized to produce geothermal power for internal use, reducing the dependency on the electrical grid, as apparent for Denbury's Laurel Oilfield [8]. When considering the applicability of ORC technology for small capacity generation, equipment and installation costs must be carefully considered.

The potential of geothermal production and selection of energy usage depends on many factors. In open-loop systems, the water's pressure, temperature, and flow rate are all a function of the local well depth, geothermal gradient, and porosity and permeability of the reservoir rocks. In a closed-loop system, besides temperature, the annulus needs to be completely cemented. In many abandoned oil and gas wells, only part of the well is cemented. Therefore, well information pre-available in industry databases can give an idea of the potential success of projects.

3.2. Data availability

Data availability is pivotal for the success in the exploration and development of geothermal projects. One of the advantages of repurposing oil and gas wells into geothermal wells benefits from prior investments in reservoir characterization, geomechanical modelling and productivity analyses developed to maximize oil and gas extraction. It is notable that these studies require extensive lab testing and data acquisition, such as for seismic data, that are highly capital intensive – but are nonetheless available at no/low cost to future repurposing designs. Nevertheless, such sets of information may not be available for many old wells. Information about the well design and state of cementation, for instance, can help prevent unnecessary work and save days of operation. However, well information is not always complete, with gaps and unknown well conditions that can lead to increased uncertainty when attempting to harvest geothermal energy [23]. Where data gaps exist, it is worth considering gathering data, such as well logs, from the well in order to confirm current well conditions. Additional challenges include absence of centralized data, different types of data and standards and often poor-quality data, especially on orphan wells and non-operated assets, and limited sharing of experience and knowledge,. Orphan wells are wells that were not properly abandoned or left unplugged. Information management and technology, as we know it today, was not implemented at that time. As a result, most of the drilling data available today exists only as hard/paper copies or their scanned versions that are not easily controlled, leading to data quality loss. Currently, all operations are extensively documented but most often remain confidential, especially if it involves failure. In addition, workovers often modify well design if repurposed during their lifetime and sometimes not properly documented [17]. Based on previous studies and projects, Liu et al. [101] proposed a workflow for heat extraction from oil and gas wells, considering data from four elements – surface facilities and generator, producer, injector, and reservoir.

3.3. Underground infrastructure

At the end of the productive life of oil and gas wells, cement plugs are placed as barriers at various depths to prevent interzonal communication and fluid migration that may pollute underground freshwater sources, in an operation called plugging and abandonment (P&A). Should the abandoned well be repurposed into a geothermal well, it is imperative to have detailed information regarding the location and integrity of this plug (length, depth, composition). Once the wellbore has been carefully isolated, the surface equipment and structures may be removed to restore the well site to a state as close as possible to the original. However, after P&A, access to the wellbore becomes impractical. Therefore, the decision on repurposing hydrocarbon wells into geothermal wells must be made prior to surface decommissioning [5].

Guidance on the assessment of conversion of abandoned wells is extremely limited, although some concerns are clear. Despite following the same procedures, each well abandonment is unique and provides different challenges. For instance, if rigless P&A (abandonment without the use of a rig) is employed, the downhole equipment does not need to be removed as long as the integrity of the well barriers is attained [16]. As opposed to conventional P&A where the tubing is removed (Fig. 7).

Coproduction systems offer the simplest conversion, where only minor modifications are required for geothermal power generation, especially if a large number of producing wells are connected to a central facility for water separation. However, many producing oil and gas fields today do not incorporate a central separation facility [56]. Fields with a small number of wells per separation facility may limit the amount of available flow for a power generation unit, leading to higher costs in infrastructure and lower capacity ORC equipment. In closed-loop systems, the wellhead needs to be modified so the BHE can be installed and working fluid can circulate through BHE independent from the geothermal fluid production. The BHE replaces the tubing and may require a rig or special cranes to perform the installation.

3.4. Well integrity

Well integrity is a safety concern that prevents fluid migration through the casing or cement sheath to different formations or to the surface. Compromised well integrity can jeopardize the repurposing project or require extensive workover before the project even starts. As demonstrated in previous works, wells abandoned

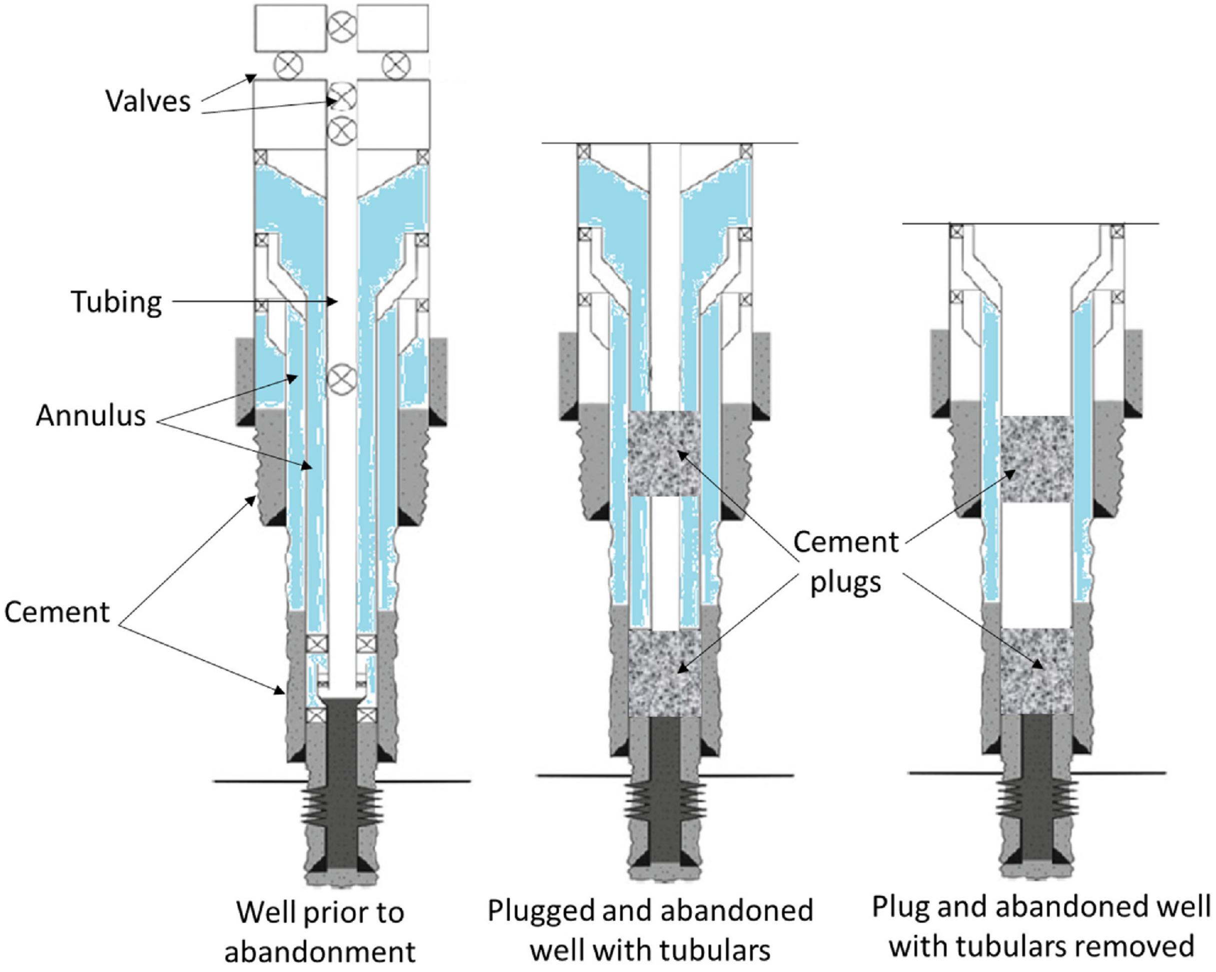


Fig. 7. Illustration of the plugging and abandonment process in cases where the tubing remains or is removed from the well; the wellhead is removed and cement plugs are placed inside the wellbore.

for extended periods are prone to leakage [102]. The leakage rates of hydrocarbons (primarily gases) from these wells are typically low due to depletion of the reservoirs and the leakage risks have been managed either through monitoring or periodic venting. Geothermal wells usually face integrity issues during drilling due to high temperatures, high pressure zones and highly fractured formations [103–105]. Oil and gas wells are in lower temperature formations and face similar issues to a smaller extent, and most of the integrity problems have already been overcome upon completion of the drilling phase. Mature oil and gas wells, however, have typically produced hydrocarbons for extended periods and may present well integrity issues due to deterioration of casing or cement. There are several potential leakage paths in a well, *viz.* across the cement sheath, at the interface between cement and casing, at the interface between cement and formation, or around the cement (Fig. 8), which may reach shallow groundwater resources due to the presence of nearby faults or communication with permeable shallower formations. Although undesired, dissolved methane in drinking water is not considered a severe public health risk, as it can exist naturally in groundwater as a result of thermogenic and microbiological activities [106]. However, in high concentrations, it may also induce the separation of a gas phase, with risk of asphyxiation and explosions [107]. The leakage potential of the casing is little, since it is protected by cement, although in the long-term the risk increases significantly [16]. Overall, failure in well integrity is a very common issue, with around 35% of the wells worldwide exhibiting some sign of leakage.

Well leakage, if not controlled, may significantly reduce the efficiency of geothermal wells. Particularly in closed-loop systems, this has a significant impact on heat extraction. Any gap between casing and cement or cement and formation may result in reduced temperatures [108]. In open-loop systems, such leakage can decrease reservoir pressure and impact flow rates. Any communication between different zones may lead to contamination of aquifer by geothermal fluid. Prior to repurposing a hydrocarbon well to a geothermal well, well logging tools can provide a rapid and relatively inexpensive initial evaluation of the state of the cement and casing. Depending on the result, the well might need intervention and workover operations to restore the casing string and cement to ensure the sustainability of water production. Although excessive leakage may be considered as a negative in repurposing of oil and gas wells, an appropriate policy by states may provide an incentive in repurposing wells to both seal against fugitive emissions of GHGs and to take advantage of extracting heat from them.

3.5. *Regulatory factors*

There is no doubt that repurposing wells is a new concept that has not been considered at a large scale. Considering the sensitivity of potential hazards and leakage that could be initiated from these wells, the hesitation of the regulatory bodies in allowing such

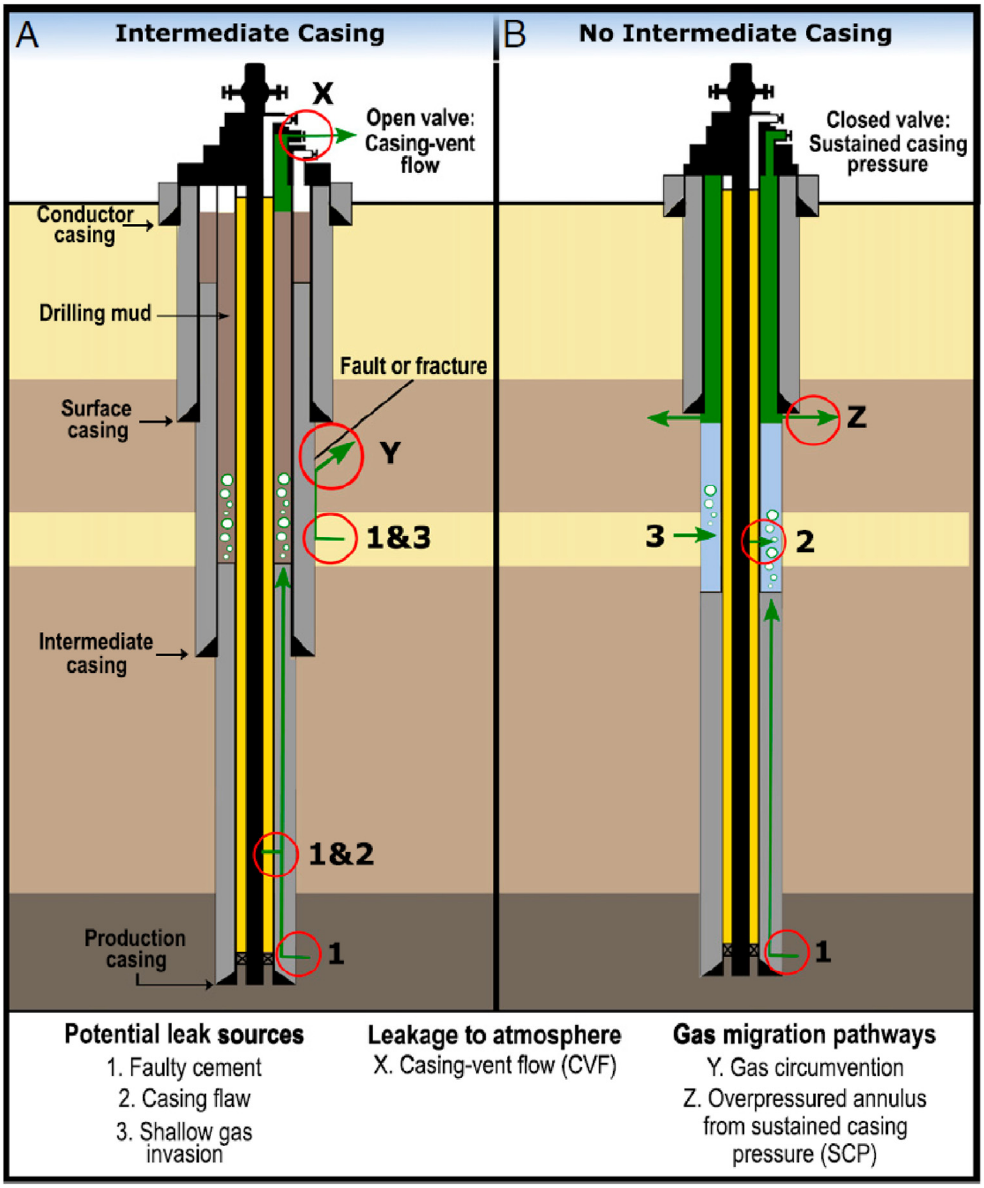


Fig. 8. Potential gas migration paths in a wellbore. Well leakage reduces the efficiency of geothermal wells (adapted from Lackey et al. [91]).

conversions is understandable. Naturally, the implementation of risk management frameworks vary in accordance with the location. The code of practice for deep geothermal wells NZS 2403:2015 [109] is the norm usually adopted as the standard for designing geothermal wells. However, most geothermal wells are regulated by mining authorities during drilling, construction, operation and plugging. Therefore, geothermal operators should follow the specific regulations of that authority. The exploitation of geothermal resources may also fall under existing legislation and regulatory frameworks for natural resources, hydrocarbons, geology, groundwater and planning [110]. The reason is in part due to the geothermal industry not having a unified authority (in terms of legal and regulatory acts). There are several subcategories of wells in the oil and gas industry, such as exploration, storage, production, injection, suspended or temporarily abandoned and P&A wells. Hence, depending on the intended usage of the well, the requirements might be distinct. This distinction is important when converting each well for geothermal energy, either production or injection.

According to US laws [111], in order to reactivate an inactive well, the company responsible must make sure there are no leaks in the wellhead, control systems and lease facilities, and perform repairs if needed. In addition, all operations must be documented, and the regulatory agency must be informed of the reactivation of the well. Additional steps should be taken if the well is converted into an injection well, specifically a Class II well (with fluids consisting of brine or freshwater). In the US, injection wells are overseen by either a state or tribal agency or a regional office of EPA. The operator can convert a previously drilled well into an injection well by submitting an application for a change of well status.

Geothermal projects, reportedly, can take 7–10 years to be brought online due to regulatory barriers [112]. A variety of factors contribute to this lengthy permitting process, including lease nomination backlogs, lack of knowledge of geothermal development, understaffed offices at regulatory agencies. In particular, under the National Environmental Policy Act (NEPA), the project requires multiple environmental reviews if located on federal land (which is the case for 90% of the geothermal resources) [29]. When repurposing a well, many initial assessments are unnecessary and may speed up the process. The administrative procedures appear as a major obstacle to transferring from a hydrocarbon license to a geothermal one. To produce geothermal energy, the operator must have the right to do so [113]. Therefore, the main entity in this industry is the geothermal operator. Regulations vary from place to place, for instance, based on Federal and Texas state laws, the holder of the mineral rights also has the rights to geothermal resources. Thus, the royalties of the exploration the geothermal resources go to the owner of these rights. Gosnold [57], mentions reaching an agreement with the well operator as one of the biggest challenges to initiate the conversion project. As demonstrated in this review, several projects and studies have confirmed the technical viability of repurposing abandoned wells into geothermal wells. In order to increase interest and facilitate operations, more supportive policies and regulations are needed.

4. Discussion

The potential to repurpose oil and gas wells into geothermal wells can be advanced as a result of: (1) accommodating environmental concerns about abandoned wells, (2) more incentives provided by the governments, (3) more engagement of the oil and gas industry in geothermal development and (4) improvements in low-temperature power generation. However, since most companies pursuing these projects are highly competitive startups, the information detailing some of these projects is unavailable, and the technical details are sparse. While there have been sporadic attempts to pursue this idea in the past, more organized efforts are attempting to develop this technology.

The geothermal industry has traditionally relied on oilfield technology adapted for high temperature conditions and larger well diameters, especially when it comes to drilling and completion. However, both industries share many more transferable technologies. The large knowledge and skills set accumulated in the oil and gas industry are highly beneficial in defining and understanding possible growth directions in the relatively young geothermal industry. Some of the critical points the geothermal industry needs to address are the necessity to decrease uncertainties on profitability, faster deployment, and to increase sustainability of large-scale projects from conventional assets. These uncertainties can be partly addressed by more comprehensive reservoir characterizations conducted by the oil and gas industry, where it is rare to find such detailed studies in the geothermal industry. In this context, the use of existing wells is a symbiotic benefit to both industries: the oil and gas companies avoid the cost of abandonment, and the geothermal companies avoid the cost of drilling new wells. Abandoned wells also offer the opportunity to be extended to a deeper depth or to drill a lateral well to access improved thermal conditions or broader heat recovery coverage at a lower cost. Thus, besides eliminating the largest obstacle of significant initial investment in drilling, repurposing oil and gas wells to geothermal wells offers better conditions to advance geothermal projects, as well as benefit oil and gas operators in return. The potential of geothermal production and selection of the energy usage depends on the data collected during hydrocarbon production. Therefore, wellbore information available in oil and gas databases can provide a real idea of the potential for success.

Many countries are currently developing renewable sources of energy, with the growing interest in reutilizing oil and gas wells for geothermal energy, CO_2 storage and hydrogen storage. However, if the regulations do not address the specific points brought up in this review, it might obstruct or delay the development of these technologies and even ward off interested players. One alternative is integrating policies on repurposing abandoned wells into geothermal regulations. Regulations should not only support the adoption of this technology but also ensure safety measures, specifically the importance of wellbore integrity to prevent potential leakages.

Of all analyzed projects, co-production is in a more advanced stage based on the technology readiness, as supported by positive field trials. The potential contribution of co-production might not be as large as from conventional hydrothermal reservoirs or EGS, but this technique benefits from recovering additional energy from a source that is already being exploited. The produced water, in many cases, is undesired and re-injected underground in order to increase the reservoir pressure and contribute to the total fraction of hydrocarbons recovered during production. In this case, the implementation of a geothermal project using this co-produced water is straightforward. The power output from the cases previously reviewed was very low, sufficient only to accommodate existing pumping operations. The natural decline of pressure in the wells due to depletion makes this method more like a temporary fix rather than a long-term solution.

Conversely, Enhanced Geothermal Systems (EGS) provide the most significant potential for future baseload needs but requires further research and development to make a significant contribution to geothermal power generation. Despite significant government sponsored research beginning in the 1970s, EGS has thus far been largely unsuccessful in establishing and maintaining production. The high costs associated with drilling and hydraulic fracturing and uncertainties regarding the nature of the reservoir have limited large-scale private-sector investment. More likely, about 10% of the injected water in these systems can be lost to the formation. During the production life of these wells, operators need to avoid any “fast paths” that would thermally “short-circuit” the reservoir and cool the returned fluids. Long large fractures potentially exacerbate such short-circuiting of the circulation paths and potentially limit the economic feasibility of EGS projects. Currently, there is no effective way to control the direction of fracture paths or alter the closure stress in the rock to engineer the geometry of induced fractures in the subsurface. However, the intrinsic low permeability of shales makes this approach an attractive option for heat extraction. Therefore, repurposing multiply hydraulically fractured horizontal wells may prove to be a much cheaper solution but has yet to be tested. Although temperatures are generally low, these wells have been extensively studied and tested during their production life and may reveal important reservoir characteristics, even microseismic data may aid the decision-making process.

Of all options for the repurposing of abandoned wells projects, closed-loop systems have received the least attention. However, the authors suggest that this technique could herald the future as this technology is the cleanest of the methods by only circulating a working fluid with no contact with the formation. This method can be achieved by avoiding any uncertainties in the rock properties and can be implemented as a remedial solution to failed EGS and coproduction wells. However, the resulting power output from these systems so far has been very low. Power generation is not infeasible but is limited by the conductive heat transfer rate. With more sophisticated technologies and in developing high thermally conductive zones around the well, this method can potentially be a gamechanger. In its current state, it seems that closed-loop systems are better suited for direct heating rather than power generation. Repurposing long horizontal wells might overcome this limitation, as the fluid is exposed over an extended heat-transfer area. An important ongoing area of study would be to ensure well integrity since the presence of a gap between casing and cement or between cement and formation may diminish the heat extraction rate.

5. Conclusion

Advances in low-temperature binary power generation methods and growing concerns regarding greenhouse gas emissions from abandoned oil and gas wells have led to growing interests in converting these wells into geothermal producers to reduce the environmental impacts of these wells and marginally benefit from generated power. This review presents a comprehensive summary of different geothermal systems and how they can be utilized for repurposing existing oil and gas wells. We report on various pilot projects and feasibility studies that have been performed worldwide. As most existing oil and gas wells are present in areas of low temperature gradient, co-production and open-loop systems are not likely to meet technical and economic expectations. However, the advent of closed-loop systems is a promising major development for this area in the near future. The main benefit of such repurposing efforts is in avoiding drilling and completion expenses and alleviating the risk of existing reservoir conditions – all principal costs and risks in the development of geothermal projects. Despite current challenges in power generation from these wells, using them for direct heating, especially in cold climatic regions, has established successful examples to be followed. In summary, this area is expected to see drastic expansions in a foreseeable future as it is trying to align significant environmental benefits with economic advantages.

CRediT authorship contribution statement

L. Santos: Data curation, Writing – original draft, Visualization. **A. Dahi Taleghani:** Conceptualization, Methodology, Writing – review & editing. **D. Elsworth:** Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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