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Geothermal Potential of the Global Oil Industry

Jon Gluyas, Alison Auld, Charlotte Adams, Catherine Hirst, Simon Hogg and Jonathan Craig

Abstract

There are around 40 new geothermal power projects commissioned in each of the last few years. Growth of the market is around 5% annually and current installed capacity is about 13,300 MW with about the same in development in 24 countries. These figures are impressive, but they do not bear comparison with any of the fossil fuels. However, few will realise that the global oil industry has a cryptic geothermal power potential that is equal to the entire current output of the geothermal industry. The oil industry is ageing. Many areas still produce copious quantities of oil, but the oil comes with an unwanted by-product, water. The volume of water produced is typically is 10–20 times that of the oil; and the water is hot—in some places very hot ($>100^{\circ}\text{C}$). In a recent study we showed that the power depleted oil production platforms of the North Sea's North Viking Graben produce sufficient hot water to deliver around 60% of the power requirement for each field. A review of global oil and hence water production has enabled us to calculate that power production alone from waste water from producing oilfields could be at least 15,000 MW.

Keywords: geothermal energy, waste water, power production, organic-rankine engine, geothermal heat

1. Introduction

In 2014, power production across the whole of the global geothermal industry was around 12,000 MW [1]. Once in production, geothermal power plants have a near zero carbon footprint and because of the constancy of the temperature of the earth at depth they tend to provide a good base load power supply.

The oil industry also produces hot water, some of which could be used to generate power either to supplement oilfield operations or for export. In particular as oil fields age there is a tendency for water (co) production to increase as the oil becomes depleted and because in most instances the oil is more viscous than the water in associated aquifers. In consequence water can become the most dominant fluid produced. This is particularly the case where water is injected on the periphery of a field or beneath the oil zone. The injected water can re-emerge at the production wells. Such water is heated by its passage through the matrix of the reservoir and in many instances the produced water is at the same or nearly the same temperature as the oil.

Hot water can be employed to generate power using an organic Rankine cycle engine. Here we examine global co-produced water production of the oil industry and hence the potential for geothermal power generation.

2. Global oil production and co-produced water

Global oil production stood at 87 million barrels per day in 2013, having risen steadily for over 25 years. Even the global economic downturn at the end of the last decade had only a small impact on this trend, reversing it for 1 year only in 2009 (**Figure 1**). During the past few decades several new oil provinces have come into

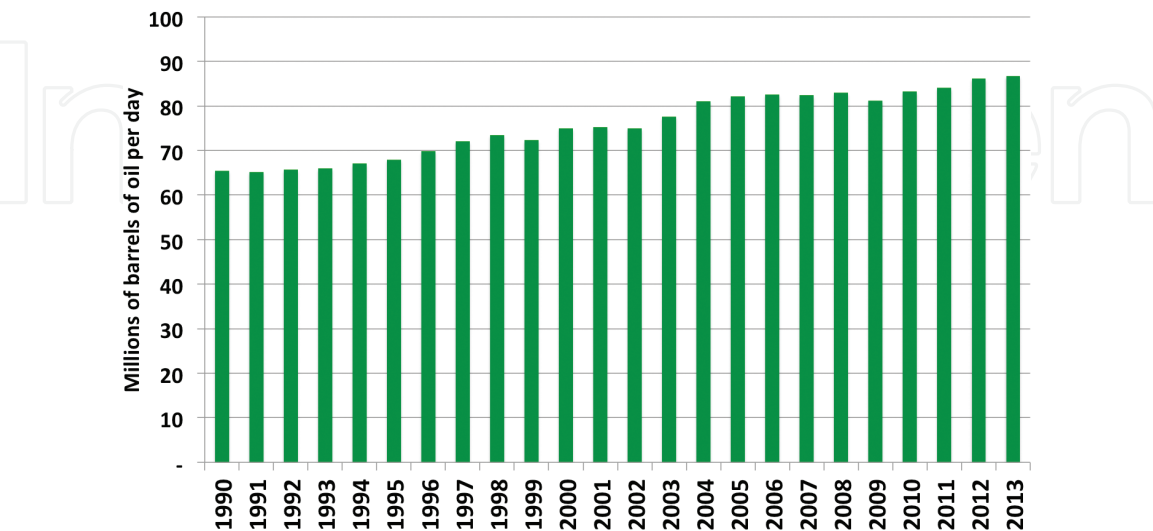


Figure 1.
Global oil production from 1990 to 2013 [2].

production, (e.g. West Africa, sub-salt Brazilian Atlantic Margin and deep water Gulf of Mexico) but more than 85% of current global production still comes from old established provinces such as those in the Middle East, Russian Federation, China, Canada, Venezuela and the North Sea. All of which have been in production for tens of years. The major fields in the North Sea have been on production for 40 years; those in Saudi Arabia, Kuwait and Venezuela around 80 years, while fields in the Zagros Province of Iran and parts of the Russia are well past their first century of production.

One thing that all of these old provinces have in common is that as well as producing oil they also produce water; water in copious amounts. Most ageing fields display a growing water production trend. The produced water may be from naturally inflowing connate (formation) water and/or water that has been injected to maintain reservoir pressure and promote sweep of the oil from the reservoir to the production wells. There are some fields that produce little water throughout their life but, typically, only a small proportion of the oil in these fields is produced (5–20%), mainly by gas exsolution drive. Indeed, it is common practice in such fields for water injection to be installed to increase the oil recovery. Much of this injected water eventually makes its way to the production wells.

The viscosity of most oils is higher than that of water, so the flow to the production well is promoted over that of water. In mature fields with active aquifers, or those that have pressure support from water injection, water will become an ever increasing and unwanted production byproduct. Water oil ratios in mature fields are typically in the 10–20 range.

3. A note on units

The petroleum industry typically follows US practice and measures production in barrels (bbl) per day. About 6.29 barrels are equivalent to 1 m³ of water. One

cubic meter of water weighs 1 tonne exactly, if fresh, or up to about 1.1 tonnes if brine, depending on the solution strength. In Europe, national bodies typically report production in partially converted SI units, with the added complication that the UK Department of Energy and Climate Change reports in thousands of cubic meters per month.

The geothermal industry tends to report flow rates in litres per second. Thus.

$$1 \text{ l s}^{-1} = 86,400 \text{ l per day} = \text{about } 543 \text{ barrels per day.} \tag{1}$$

This simple difference in units used means that oil and geothermal industry production figures are rarely compared, so the importance of the oil industry's geothermal water resource has not been widely appreciated.

4. Examples of co-produced water N Sea fields

The North Sea emerged as a globally significant oil province in the 1970s. Many giant fields were discovered in quick succession as exploration that had begun between 56° and 58° N in both the UK [3] and Norwegian sectors spread northwards and into Arctic waters (for Norway). By 1975 the first field, Argyll was on production [4] and a year later the first of the giant fields, Forties, was on production [5]. Most of the fields discovered in the North Sea are still on production, although this is changing following the fall of the oil price during the latter half of 2014 and into 2015. Nonetheless, even those fields that remain on stream will be well past their prime, with oil production levels maybe only 5 or 10% of peak levels. The modest flow of oil is accompanied by large quantities of water, typically 10–20 times greater than the oil volume. The water is a mix of injected (sea) water and connate water. Water injection is used to maintain reservoir pressure and so support production. The injected water sweeps the oil away from the injection sites towards the production wells. In many fields, the water handling is a 'bottleneck', the volume being at the limit of the handling and cleanup capacity of the facilities prior to reinjection and discharge.

For example, the Murchison Field (**Figure 2**), located in the North Sea's Brent Province, produces oil from high-quality, Middle Jurassic paralic sandstones. It came on stream in 1979 and for the first 3 years of production it produced little water (brine). Plateau oil production for the field was maintained at about

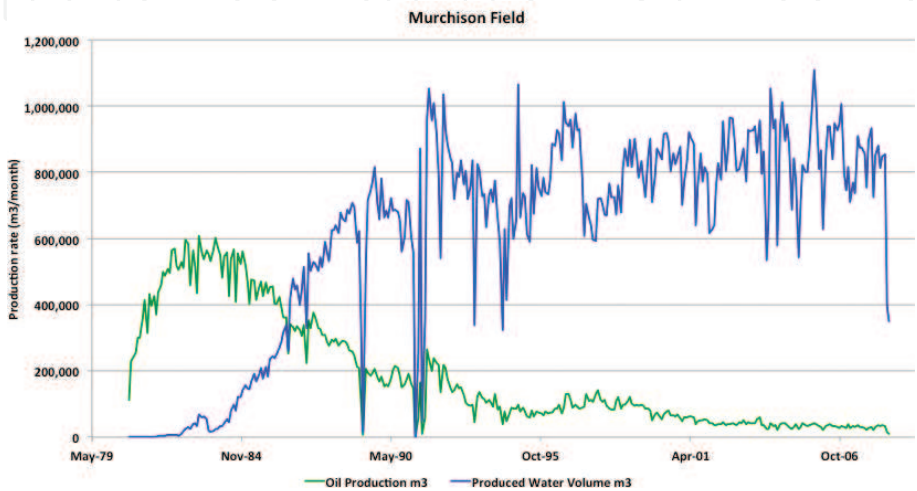


Figure 2.
Oil and water production profile for the Murchison field, North Sea.

600,000 m³/month until late 1984, by which time water production had risen from near zero to 200,000 m³/month. Total fluid production of around 800,000 m³/month was maintained from 1985 until at least 2008 but, over time, the ratio of water to oil has risen to about 30:1. The Murchison Field is located at about 3 km depth and produces oil and water at 110°C. After cleaning, the produced water is discharged to the sea [6].

Murchison is typical of the ageing suit of North Sea Fields. Many are now producing at least 10x, and some 20x, as much water as oil. While the oil price remained high relative to operating costs, production continued, but with the sustained low oil prices since mid-2014 operators are now opting to abandon fields. Water handling (processing and cleaning) is a major cost and can limit the viability of the field, even though only half the oil in the field may have been recovered. Thus, the hot water resource in the North Sea fields is disappearing fast, as it will in other oil producing regions as fields are abandoned. The situation might be different if instead of being a resource the hot water was instead considered a reserve.

5. Southampton district energy scheme & Wytch farm

The UK has a single producing geothermal well at Southampton in the Wessex Basin [7]. This well was one of six drilled in the 1980s on behalf of the British government. They were planned in the wake of the first oil crisis of the 1970, and before the UK became a significant petroleum producing country, in order to evaluate the geothermal potential of the UK. By the time the wells were drilled, the UK was a global leader in oil and gas production from the North Sea and this, coupled with difficulties encountered in retrieving any hot water from the wells drilled into the relatively hot Cornish granites, meant that the geothermal aspirations for the UK remained unfulfilled. Michael Smith, the accountant at Southampton District Council, however, recognised the potential of a zero cost, 2 km hole in the ground. Hot water produced by this well became the locus for the development of a combined heat and power project—the Southampton District Energy Scheme.

The well at Southampton was drilled in 1981. It encountered the Triassic Sherwood sandstone at a depth of between 1730 and 1800 m below mean sea level (**Figure 3**). The aquifer was 70 m thick where penetrated and 24 m of this was deemed producible. The measured temperature was 76°C and flow rate of the well was 10–15 l s⁻¹. Construction of the facility began in 1987 and, at the time, it was estimated to have a 10–15 year life [7]. In fact, it continues to operate today, albeit at reduced flow rate, and the thermal output is about 1.7 MW (at 2 l s⁻¹). The ‘heat-depleted’ water is not reinjected into the reservoir but is discharged at about 50°C into the nearby Southampton Water (sea).



Figure 3.

Triassic Sherwood sandstone exposed in the coastal cliffs of Ladram Bay, Devon, UK. This sandstone has high net to gross, high porosity, high permeability and a high vertical to horizontal permeability ratio. It also forms the main producing reservoir in the Wytch farm oilfield and the producing horizon in the Southampton District energy scheme, both located further east along England's south coast (photograph by J. Gluyas).

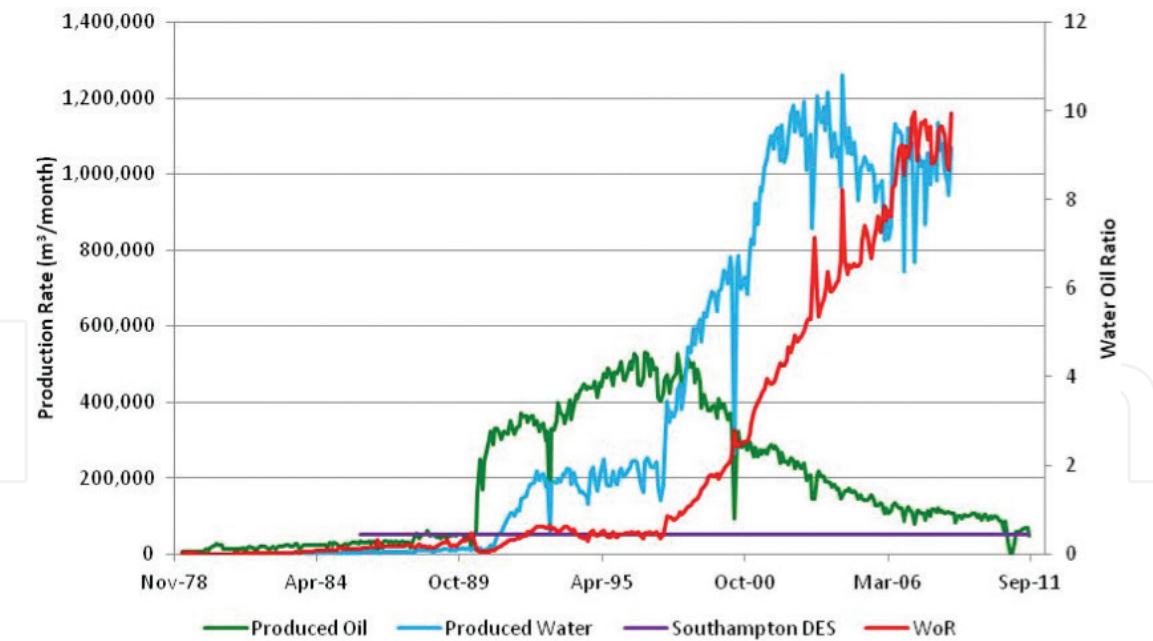


Figure 4.
Comparison of production of water from the Southampton District energy scheme (purple) with production from Wytch farm (oil = green, water = blue and the water to oil ratio = red). At peak, Wytch farm was producing 40x as much fluid as Southampton District energy scheme.

Aside from the fact that the Southampton District Energy Scheme is the only geothermal project in the UK, there is nothing remarkable about it. What is remarkable is that only a few tens of kilometres away from Southampton another ‘scheme’ was producing 40 times as much hot (67°) water, none of which has been used for any district heating.

The Wytch Farm Field in Dorset is the UK’s largest and Europe’s second largest onshore oilfield (**Figure 4**). Developed initially in the 1970s, it was later extended in the 1990s to exploit the larger and deeper Triassic Sherwood Sandstone reservoir. Petroleum production peaked in the mid-1990s at 0.5 million m³/month while, 10

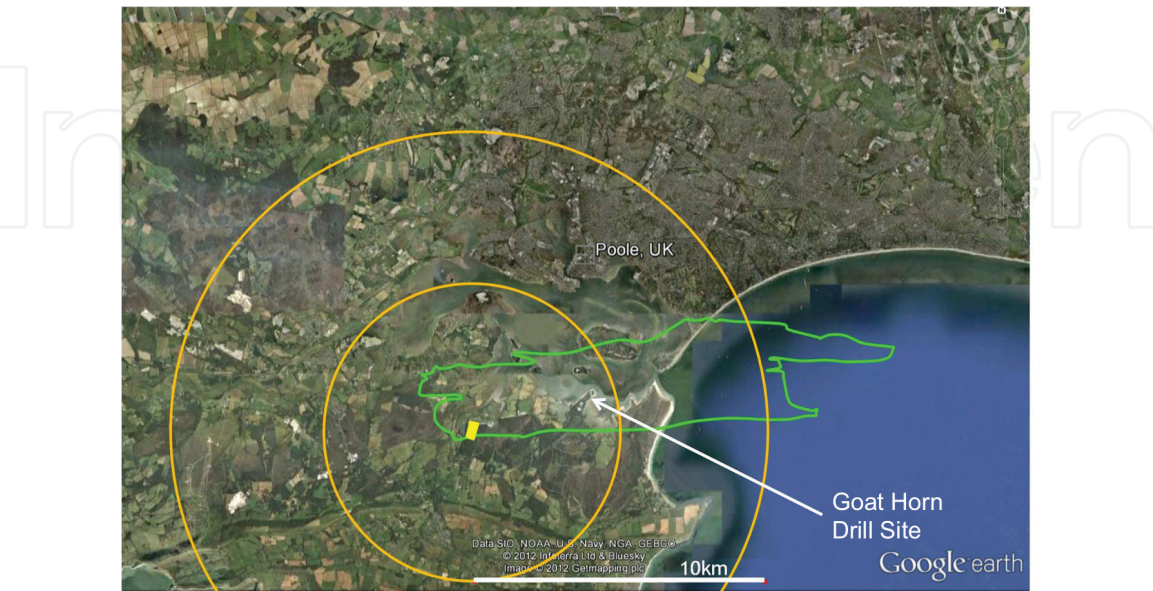


Figure 5.
Location of the Wytch farm oilfield (outline in green) relative to the Poole and Bournemouth (top right hand corner of figure) urban areas. The concentric circles are 5 and 10 km radius and centred on the Wytch farm gathering station. District heating schemes typically lose up to about 1°C km⁻¹ of insulated pipe [8]. GH is the location of the Goathorn peninsula from where long reach, horizontal wells were drilled into Poole harbour and is the location of the well heads closest to Poole-Bournemouth [9]. Base image from Google earth.

years later, total fluids production reached 1.5 million m³/month, 90% of which was water. Oil is exported from the gathering station via pipeline and, during the build up to peak oil production, a chiller was installed so that the exported oil did not warm the earth surrounding the pipeline. The produced water is either cleaned and disposed of, or is re-injected for water maintenance. At peak, the field was producing around 570 l s⁻¹, compared with the 10–15 l s⁻¹ from the Southampton well. Hence, the flow rates and hence low enthalpy geothermal potential of the Wytch Farm Field exceeded that of the Southampton project by some fortyfold.

Despite the proximity of Wytch Farm to the urban areas of Poole and Bournemouth (population c. 350,000 in 2015; **Figure 5**), no one seems to have considered the possibility that the co-produced (and hence ‘free’) geothermal water from Wytch Farm could be used—indeed could still be used—to heat commercial and domestic property in these areas.

6. Power generation

For most of the geothermal energy industry, dry steam is used to drive steam turbines and so generate electricity. The steam is produced by circulating water through hot rocks close to the Earth’s surface. Temperatures typically need to be 150°C or greater. However, lower temperature wet steam and even hot water can be used to generate electricity using a variety of heat engines, the most common of which are organic Rankine cycle engines (ORC). In these, the hot water is used to vaporise a volatile fluid and the vapour drives the turbine. The vapour is then condensed and the cycle begun again. For example, at Chena Hot Springs in Alaska, USA, hot water at about 73°C is used to generate around 400 kW of geothermal power using ORC [10]. The critical factor is the difference between the temperature of the hot water and that of the condensing fluid, not the absolute temperature of the water.

In a recent study, Auld et al. [11] examined the power production potential for a suite of oilfields in the Northern North Sea (Brent Province), including the aforementioned Murchison Field. Here, the condensing fluid is the cold North Sea (approx. 5°C). For many fields in an offshore setting, the co-produced gas that exsolves from the oil as it is brought to surface, is used to produce electrical power. Gas turbines generate the power required to run the platform. The largest consumer of power are, typically, the large water pumps used to inject water into the reservoir and so maintain pressure and assist in the sweep of oil to production wells. In this regard, the Brent Province is problematic. Its oils contain relatively little dissolved gas and as the oil production declines so does the gas production. For many fields, this reduction in gas supply means that the fields cannot be run optimally, as not enough water can be injected to maintain commercial rates of oil production. For one company at least, failure to produce oil at commercial rates has led to the premature abandonment of a field with only 45% of the in place oil recovered. In mid-2015, Fairfield Energy announced their plans to abandon the Dunlin Field and its satellites [12]. The abandonment may have been postponed had the co-produced water from the field been used to produce power and offset operational costs as well as, in this instance, the cost of building of a new, expensive gas import pipeline that was little used before the abandonment of the field was announced.

Auld et al. [11] demonstrated that the six Brent Fields studied in detail could have produced more than 10 MW and one, Ninian, 31 MW (**Figure 6**). A comparison of the cost of the ORC system sized for 10 MW power generation showed that payback was between 3 and 4.5 years. This payback time did not account for

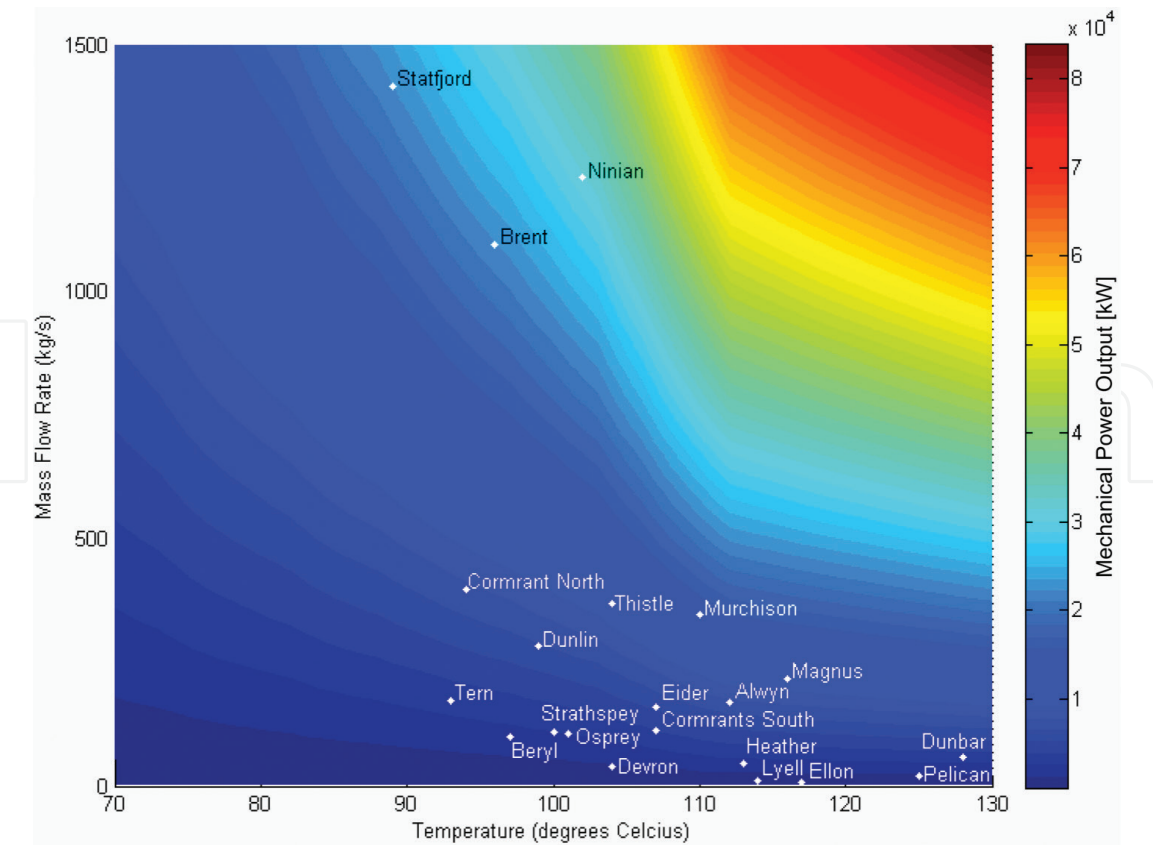


Figure 6.
Brent Province oilfields, potential power output of organic Rankine cycle fuelled by co-produced hot brine (from [11]).

greenhouse gas emission levies that would shorten payback, nor for the additional benefit of using the spent cold brine for reinjection into the reservoir. The increased viscosity of the cooler injection water improves its mobility ratio compared with that of oil and hence improves sweep efficiency.

7. UK co-produced water

The UK Department of Energy and Climate Change continuously releases near up to date oil and water production figures and water injection figures for all UK offshore oilfields. The North Sea production peaked in 2000. At peak about 8 million barrels of oil plus water were being produced every day, of which about 5 million barrels were water. Since 2000, production has declined with oil production falling faster than water production. Indeed, water production was still 5 million barrels per day in 2007, but it has fallen somewhat since (**Figure 7**).

Many of the North Sea fields produce from depths of around about 3 km and, although there is some variation, the geothermal gradient over much of the North Sea is about $30^{\circ}\text{C km}^{-1}$, a little higher around the triple (rift) junction in the Central North Sea. Using field and reservoir temperature data published in [13] for 69 fields (data tables at end of each chapter), the average temperature of oil and brine produced from North Sea Fields is $108 \pm 26^{\circ}\text{C}$ (**Figure 8**). Of these 69 oil fields, over 80% are at temperatures in excess of 90°C . Using the approach of [11], a daily production of water of 5 million barrels, a reservoir temperature of 100°C and a condensation temperature of 5°C yields a theoretical power resource, using all available co-produced water to generate power, for the North Sea of around 250 MW.

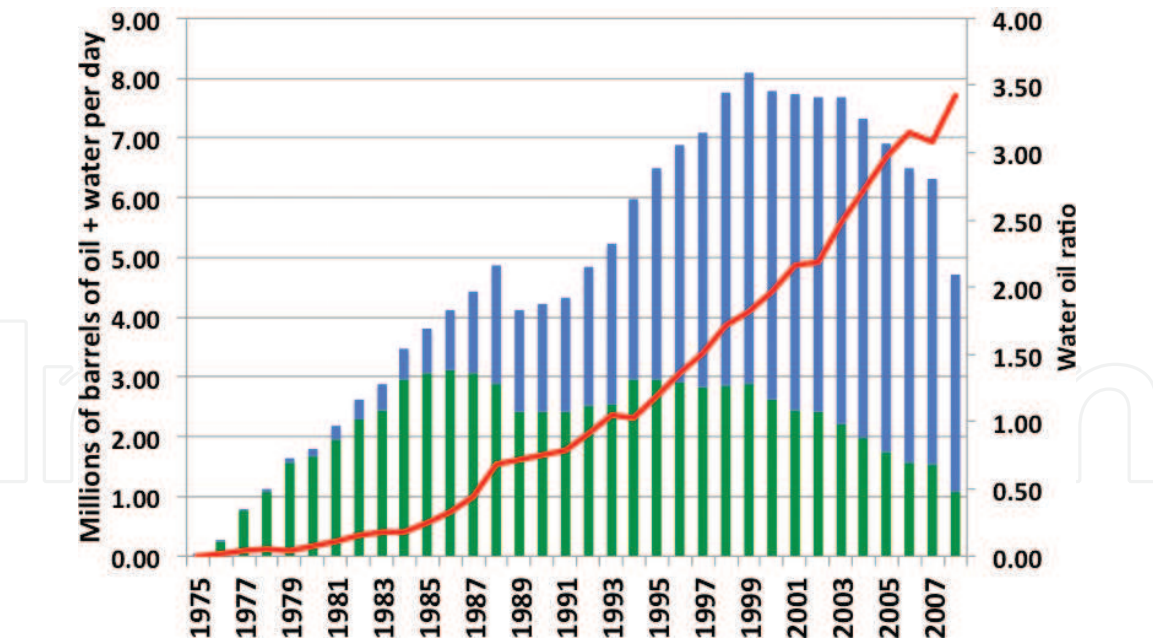


Figure 7.
UK North sea oil production (green) and co-produced water (blue) with water oil ratio trend in red.

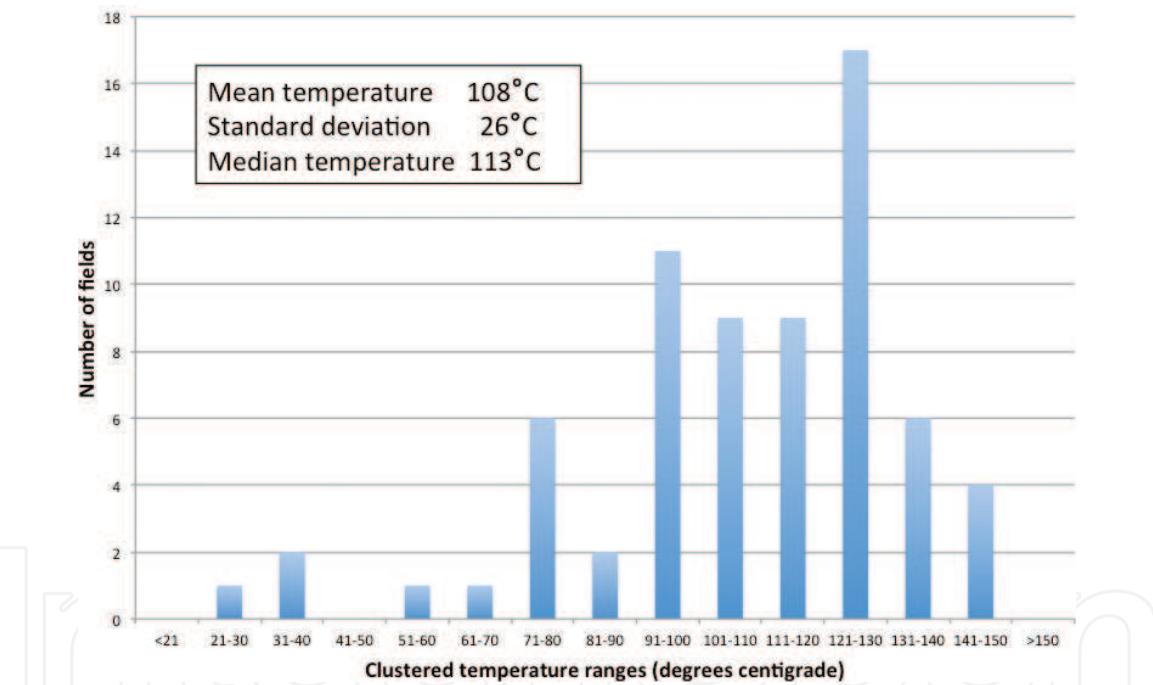


Figure 8.
Temperature distribution of North Sea oilfields (from [12]).

8. Global co-produced water

Translating the geothermal power potential of the North Sea fields to make an estimate for the whole world is extremely difficult; not because of the calculation itself is difficult, but because data on temperature of producing fields and volumes of co-produced water are kept confidential by many companies and countries. This is particularly true for the water production data, because it is straightforward to use the evolving water to oil ratio in a field, or indeed basin, to estimate remaining reserves and remaining reserves are often state secrets and the data that are release are often subject to political overprint. Nonetheless, it is possible to make a broad estimate of global water production, particularly in view of the known and changing discovery rate for petroleum over the decades (peak finding time was the 1960s).

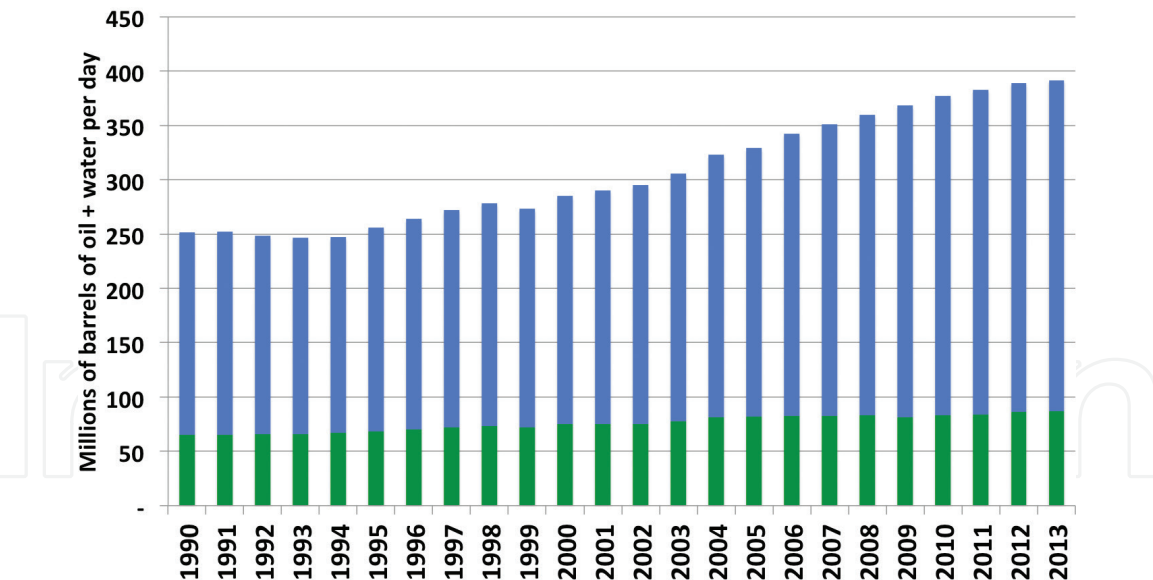


Figure 9.
Global water production amounts to about 300 million barrels per day from which as much as 15,000 MW of power could be generated.

To do this, we have used a combination of primary and secondary sources, most notably: Dal Ferro and Smith [14] and an anonymous white paper from the Society of Petroleum Engineers [15, 16] on ‘Challenges in Reusing Produced Water’. **Figure 9** combines global oil production data from the aforementioned BP Statistical Review of World Energy and the references cited above. Global water production is around about 300 million barrels per day and about 3.5 times as much as daily oil production (**Figure 9**). About 70% of oil (and water) production is from onshore. We do not know the average temperature of oilfields around the world but speculating that it is not much lower than that of the North Sea would lead to the conclusion that waste water from the oil industry could deliver around about 15,000 MW. The very large assumptions used to make this calculation mean that this figure should be treated with some caution. Nonetheless, such a figure is about the same as the total current global output of the geothermal industry. This implies that the untapped geothermal resource intrinsic within the oil industry could, if used, double geothermal power production across the globe and at modest cost since the hot water is already produced. In addition to the potential power generated the substantial residual thermal energy could also be used in many parts of the world.

Moreover, as oilfields age further, efforts to maintain oil production are likely to result in an ever-increasing water oil ratio and, most likely, the production of more water – and, hence, more geothermal resource.

9. Conclusions

Today, dedicated geothermal plants produce about 13 MW globally. The oil industry could generate much the same amount of power by processing the co-produced water from ageing fields to produce power using Organic Rankine Cycle engines. If co-produced water was considered as an asset rather than a waste product, it is likely that oil fields would be operated longer with ever-increasing water oil ratios and the geothermal utility of the fields would increase. Utilisation of the geothermal resources from oilfields would also help curb emissions by reducing the amount of co-produced gas used for power generation and ultimately allow more oil to be recovered from the fields because they could be run economically for longer with even lower oil production rates.

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