Geothermal Heat: Status Quo or Deeper and Down?

Dave Banks explores the economics of shallow versus deeply sourced geothermal heat, showing that the balance between drilling and electricity costs ultimately determines which type of project is favoured.

Words by Dave Banks
18 April 2022

Geothermal well head at Ammerlaan TGI's Pijnacker scheme, The Netherlands. The wells access a sandstone reservoir at depths of at least 2.1 km, delivering water at 76°C to supply horticulture, district heating and a swimming pool. Photo reproduced by kind permission of © David Walls 2022.

Geothermal energy is heat that is stored and transmitted in Earth's subsurface. This may be relatively "cool" heat (~10°C), present in the upper few metres or tens of metres of subsoil or rock. To use this heat, we can install a heat exchanger (often loops of polyethylene pipe in a trench or cheap shallow borehole) and a heat pump to extract it from the ground and deliver it at a higher temperature as space heating.

Geothermal energy may be found in warm or hot water (~30 to 90°C), stored at maybe 1–3 km depth in a permeable reservoir. For example, in Southampton, since around 1987, groundwater at over 70°C has been abstracted from a 1.8-km-deep borehole that taps into the Triassic Sherwood Sandstone, contributing 1–2 MW_{th} of heat to a district energy system.

Geothermal energy may also comprise very hot water or steam used to generate electricity via turbines. Conventional systems require a fluid over 170–180°C to generate steam for this purpose, but lower temperatures can be used to boil organic fluids in a closed cycle, whose vapour is used to turn turbines – so-called Binary or Organic Rankine Cycle systems (an alternative, the Kalina cycle, uses an ammonia-water mixture). An example of this is the recent Cornish United Downs project, where boreholes were drilled to ~5 km depth into a steeply dipping granite fracture zone, through which water is circulated. The fracture zone effectively acts as a huge subsurface heat exchanger, allowing the plant to generate both electricity and industrial heat.

A seriously large heat pump used to extract heating and cooling from mine water at a hospital in Mieres, Spain. Photo by © David Banks

Here I explore the costs associated with shallow versus deeply sourced geothermal heat. I argue that high drilling costs and, in particular, increasing "per metre" drilling rates with depth, tend to make shallow, ground source heat pump geothermal projects more economically attractive. On the other hand, an increase in the cost of electricity required to run heat pumps, relative to the price consumers are willing to pay for heat, would work in the opposite direction, favouring deeper geothermal drilling.

Ground Source Heat Pumps

Ground source heat pumps (GSHPs) are the low-carbon tool that allows us to use shallower, low-temperature geothermal resources for heating (or cooling) our buildings or industrial processes. While they have become well established in the UK since around 2000, with tens of thousands of relatively shallow GSHPs sucking heat from the upper ~150 m of the geological column, their installation cost can be unattractive to individual domestic consumers. Moreover, the electricity needed to run a GSHP costs up to 34 p per kWh_e compared to 10.4 p per kWh for natural gas (at January 2023 prices), meaning that the GSHP needs to have an efficiency of around 300% to compete with gas.

Regrettably GSHPs have made disappointingly little inroad into the imaginations of professional geoscientists and academics

Regrettably GSHPs have made disappointingly little inroad into the imaginations of professional geoscientists and academics, some of whom think that the only direction for geothermal energy is down – deeper and down – to tap increasingly hotter sources.

In this article, I ignore the use of geothermal energy for electricity generation because the economics of electricity are somewhat different to the economics of heat. While the United Downs project represents a huge achievement, I suspect that within the next few decades, the electricity generated by hot, deeply sourced geothermal fluids is unlikely to be able to compete (in terms of MWh_e generated) with more readily scalable renewable electricity sources such as wind and solar, given that the temperatures required are only found at considerable depth and that permeability may only exist or be developed at such depths in very specific geological environments in the UK. Here I focus on geothermal heat because there are relatively few competing technologies that can deliver low-carbon space heating in an exergy-efficient manner.

The value of heat

To evaluate and draw comparisons between proposed geothermal projects, we need to assign value to geothermal heat or fluids. The approach I use is based on some fairly gross assumptions, so I ask the reader to focus on the broad, important trends, rather than the exact figures.

The value of heat depends on its temperature. A hot geothermal fluid at 80°C can be used for many applications, such as conventional high-temperature district heating, lumber drying, horticulture and industrial applications. A cooler fluid, at say 30–40°C, has fewer direct-use applications: maybe aquaculture, swimming pools and medicinal hot springs, mushroom-growing or lower temperature district heating. A groundwater at a near-surface temperature, of say 12°C, has considerably lower value. It could be used for space cooling, but for most heating purposes a heat pump would be required to actively extract heat from the water to a higher temperature system. To run the heat pump requires an 'investment' of electrical expenditure, which comes at cost: the greater the step up in temperature, the more you have to invest.

The greater the step up in temperature, the more you have to invest

My approach for valuing geothermal hot water (Banks, 2022) takes a 'base price' for one kWh_{th} of waterborne heat at say, 70°C, based on a market rate for supplying district heating at this temperature to consumers. The value of lower-temperature fluids is discounted relative to this price according to the cost (electricity input) of using a heat pump to transfer heat energy from the low-temperature fluid to a higher temperature. I use this method to derive a value of 1 m^3 of warm water at a variety of temperatures (see figure A '*The modelled value of 1 tonne of warm geothermal water*' in the methods section). When electricity prices are low relative to the value of waterborne heating, the relationship between the value of warm water and temperature is approximately linear. When electricity prices are high, the cost of boosting heat from low to high temperature becomes significant and the relationship becomes much more non-linear, with low-temperature fluids having disproportionately less value.

As the value of heat increases (at worst, linearly) with temperature, and given that the geothermal temperature gradient is often quasi-linear, there seems to be benefit in exploring ever deeper for warmer geothermal fluids – if the cost of drilling deep holes weren't so frighteningly expensive.

The cost of drilling

Unfortunately, the cost of drilling per metre increases with depth and depends on the nature of the strata and the downhole conditions (overpressure, corrosiveness, gaseousness). Algorithms for estimating drilling costs based on real data (see methods section) show that in all cases, costs increase faster than depth.

For example, for hydrocarbon wells, Ogden & Johnson (2010) indicated that the cost of a 3-km-deep well is 6.6 times greater than a 1-km-deep well (based on the relationship between cost and depth proposed by the American Petroleum Institute, API), while Lukawski et al. (2014) suggested that the cost of a 3-km-deep well is 5.8 times greater than a 1-km-deep well.

For geothermal wells, Lukawski et al. (2014) found that costs are greater than hydrocarbon wells at shallower depth and lower at great depth, but typically a 3-km-deep geothermal well costs 4.2 times more than a 1-km-deep well.

Once these costs are corrected for inflation (to 2022), a 1-km-deep production borehole could cost well over £1 million (see figure B '*The predicted cost of drilled oil/gas wells and geothermal wells*' in the methods section).

Likely fluid yield

The amount of geothermal fluid that can be obtained from a well is approximately proportional to the transmissivity of the formation (i.e. the product of the permeability and reservoir thickness).

In fractured reservoirs, fractures tend to close with depth and permeability declines exponentially with depth. In granular reservoirs, porosity also tends to decrease quasi-exponentially with depth, largely due to mechanical compaction due to overburden pressure, and is dependent on clay content (see methods section). The occlusion of pore space with cements and secondary minerals (such as silica, gypsum and anhydrite) also plays a role.

For the UK's premium geothermal prospect, the Sherwood Sandstone (a granular reservoir), existing analyses (e.g. Brookes et al., 2003; Raine & Reay, 2019) suggest a broadly log-linear relationship between permeability and porosity, albeit with considerable scatter reflecting different diagenetic histories, cements and sedimentary textures in different basinal settings (see figure C '*Highly idealised porosity-permeability trends with depth*' and algorithm in the methods section). For example, in the southern North Sea, core data show a 1-log-cycle reduction in permeability for every 6–7% loss of porosity (Brooks et al., 2003). All of this implies that the permeability of granular reservoirs tends to decline with depth in a highly non-linearly way.

Synthesis

Let's consider the virtues of drilling shallower geothermal wells and using a heat pump to deliver heat, versus drilling deeper wells, which may allow direct use of heat.

Figure 1 shows the increases and decreases in various parameters, all normalised to values at 1 km depth, for an assumed typical UK geothermal temperature gradient of 25°C per km and loosely based on the properties of the Sherwood Sandstone. The value of warm groundwater increases as temperature increases. For example, its value at 2 km depth is 2.1 to 3.7 times its value at 1 km depth, depending on assumed electricity costs.

The cost of drilling to 2 km depth is 2.5 to 3.1 times the cost of drilling to 1 km. The increase in value of hot water is slower than the increase in drilling cost when the price of electricity is low. When the price of electricity is high (27 p per kWh, approaching the 2022 OFGEM price cap), then the value may well increase faster than drilling costs. Thus, the decision whether to drill for deep, hot geothermal waters, or to be satisfied with shallower cooler groundwater and greater reliance on heat pumps, depends very strongly on the relative price of electricity (and likely future price trends).

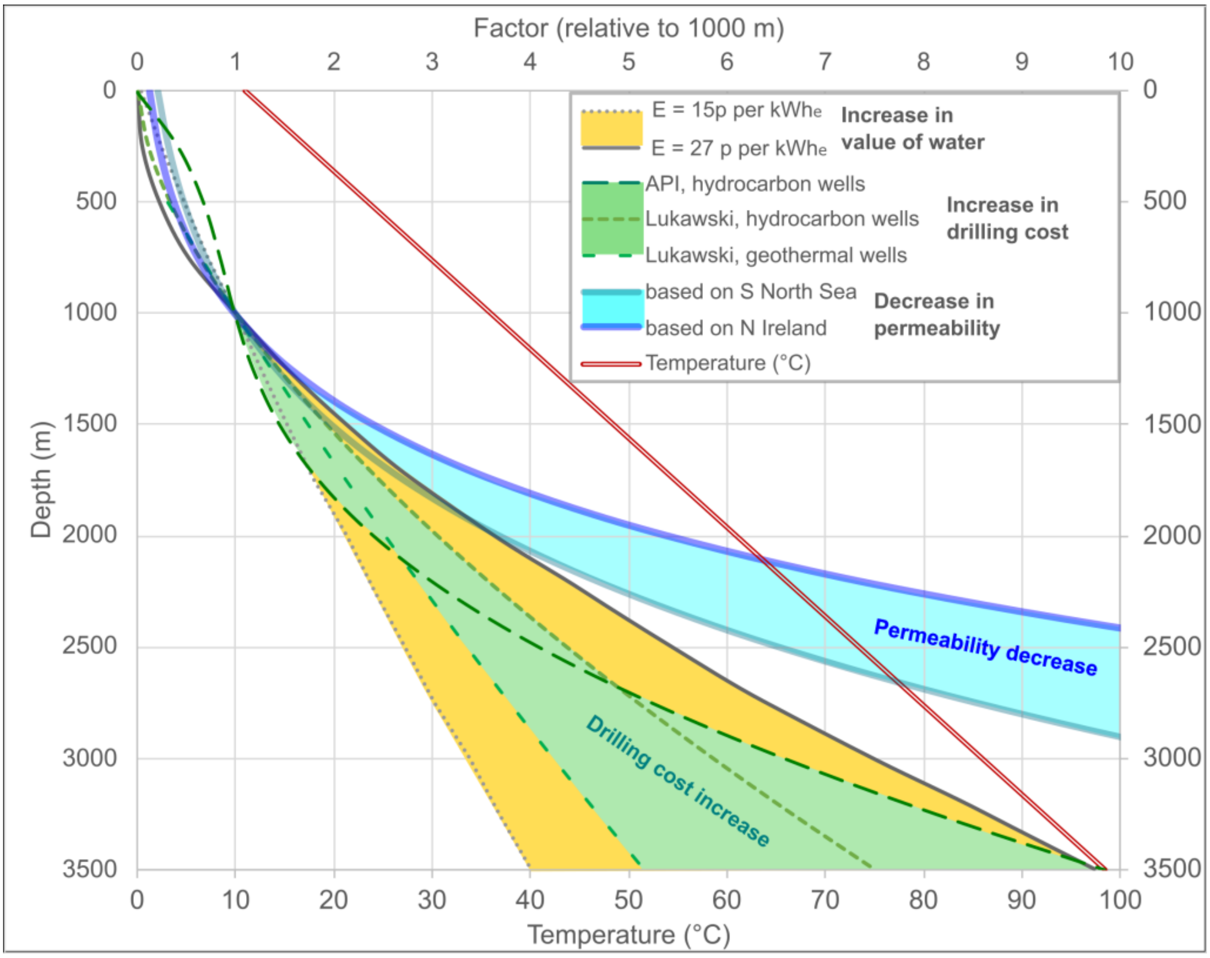

Figure 1 | Envelopes of relative trends in value of warm water, drilling costs and permeability decrease (see methods section for individual graphs), based on a geothermal gradient of 25°C per km, a surface temperature of 11°C and normalised to a 1 km borehole. E = assumed electricity cost. Permeability is based on "best fit" poro-perm relationships for the Sherwood Sandstone in the southern North Sea (Brook et al., 2003) and of onshore Northern Ireland (Raine & Reay, 2019), with an assumed uncompacted porosity of 28%.

However, the non-linear decline in permeability trumps all of these factors; the predicted permeability at 2 km could be 3.7 to 5.4 times smaller than at 1 km and the *general* decline in permeability is faster than the increase in value of water. In short: if you drill deeper, you'd better have a clear reservoir target and a permeability prognosis that bucks the trend!

Deep Borehole Heat Exchangers

An alternative technology – the Deep Borehole Heat Exchanger (DBHE) – removes the dependence on permeability at depth (Kolo et al., 2023). A DBHE consists of a deep borehole with a central, narrower-diameter axial pipe. Water is circulated down the annulus, where it picks up heat from the rocks in the wall of the borehole. The water is pumped to the surface up the axial pipe, and heat is extracted via a heat exchanger, probably coupled to a heat pump. Unfortunately, the heat yields available from such boreholes are modest, although they do increase non-linearly with depth (Fig. 2).

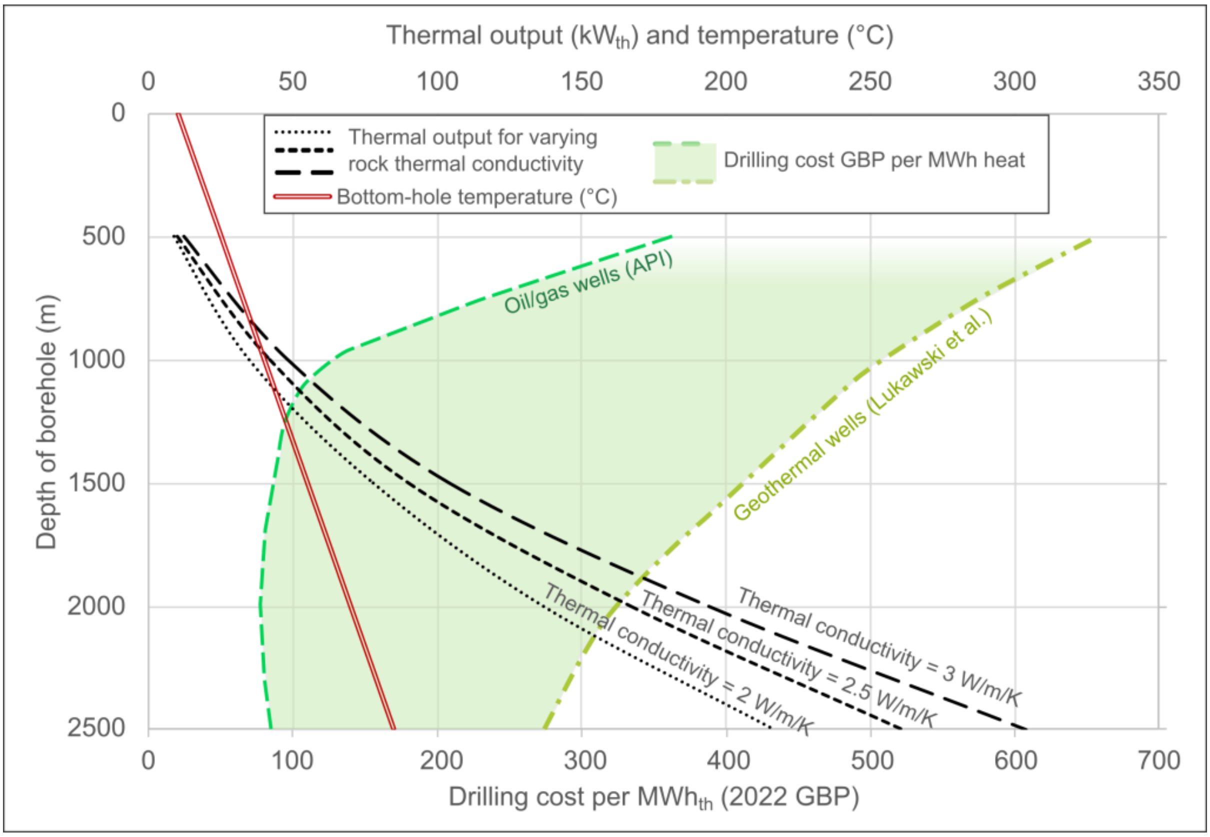

Figure 2 | Thermal output from a deep borehole coaxial heat exchanger (kW$_{th}$) for the following assumptions: 5000 hrs/yr operation, diameter = 210 mm, rock heat capacity = 2.3 MJ/m^3/K, a relatively high geothermal gradient of 30°C per km, surface temperature 10°C, borehole thermal resistance 0.03 Km/W, for a 20-year simulation using a simple line source heat extraction model. The minimum permitted mean fluid temperature at the end of simulation is 10°C. Costs per MWh$_{th}$ heat are derived by dividing the thermal output over 20 years by the drilling cost predicted by the two extreme models (API/Ogden & Johnson 2010 for oil and gas wells; Lukawski et al. 2014 for geothermal wells, corrected for inflation to 2022 prices), assuming 2.5 W/m/K rock conductivity.

Dividing the typical drilling costs by the total thermal output from a DBHE over a 20-year simulation period (kW$_{th}$ output x 5,000 hr/yr x 20 years; the green envelope in figure 2) shows that the levelized drilling costs are unattractive – typically in the range £80 to >£300 per MWh$_{th}$ – similar to, or significantly greater than the market rate for heat (and this is before other development and operational costs are included). For example, a 1,500-m-deep DBHE might yield around 90 kW$_{th}$ at 5,000 hr/yr operation for 20 years, with a total thermal yield of 9000 MWh$_{th}$. The drilling may cost £0.8 to £3.7 million, implying a levelized drilling cost of around £90 to £410 per MWh$_{th}$ of heat.

Given the current costs of drilling, the output of conventional coaxial DBHE struggles to justify the expense of drilling new boreholes. This may change if the price people are willing to pay for heat increases. It could be interesting to explore the use of DBHE in existing failed exploration wells or decommissioned hydrocarbon wells, although these will be associated with a number of environmental and safety challenges.

Several new “closed loop” borehole heat exchanger concepts are emerging. For example, the Eavor-Loop™ concept envisages MW-scale outputs from very deep, long (2–5 km) horizontal boreholes constructed between two vertical input-output boreholes at great depth (Van Wees, 2021), thus maximising the length of borehole at depth. The success of this depends on economic drilling technologies.

Finding a balance

My analyses come with caveats: I’m merely considering the value of the resource (warm water) relative to costs of drilling the borehole source (many other costs are involved in establishing a thermal energy plant), and I’m initially considering a given, highly idealised set of reservoir characteristics. With these in mind, I’m forced to conclude that *when the cost of electricity is low*, the drilling of deep geothermal wells is not economically efficient compared with the abstraction of shallow cooler groundwater and/or the use of heat pumps.

Factors that would favour the drilling of deeper geothermal wells, relative to shallow groundwater and/or heat pumps are:

- A significant increase in electricity prices relative to the price that consumers are prepared to pay for heat – and this is the situation in the UK at present!
- A significant decline in deep drilling costs, and especially the rate at which costs per metre increase with increasing depth.
- An attractive reservoir target at depth that “bucks” the general permeability-depth trend, identified through good hydrogeological characterisation or play-fairway analysis. Such a reservoir may be attractive by virtue of its great thickness and/or anomalously high permeability (e.g. particularly coarse, clay-poor, uncemented/unmineralized) or its anomalously elevated temperature or pressure.
- The co-production of other valuable components (e.g. dissolved lithium).

Finally, while shallow (50–150 m) closed-loop borehole heat exchangers *can* be attractive (cheap drilling due to lack of permanent casing), deep (500 to >2,500 m) vertical, coaxial borehole heat exchangers do not yet appear to be cost-effective in terms of heat production – *unless* they can be installed in pre-drilled deep boreholes (such as failed exploration boreholes or exhausted hydrocarbon wells). New technologies and high-penetration hard-rock drilling techniques offer some hope that deep closed-loop borehole heat exchangers may de-risk the provision of deep geothermal energy.

Author

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Further reading

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METHODS SECTION | Geothermal Heat: Status Quo or Deeper and Down?

Definitions

Ø Porosity (%)

$Ø_0$ Uncompacted porosity (%)

k Permeability (mD)

X Clay content (fraction)

α_0 Coefficient of compaction

d Depth (m or km, depending on context)

The value of heat

I use the methodology for valuing geothermal hot water outlined in Banks, QJEGH 2022. I take a “base price” of 10 p per kWh_{th} for waterborne heat at 70°C, based on a market rate for supplying district heating at this temperature to consumers. I value lower-temperature fluids by discounting this price according to the cost (electricity input) of using a heat pump to transfer heat energy from the low-temperature fluid to a higher temperature, allowing me to derive a value of 1 m^3 (strictly speaking, 1 tonne) of warm water at a variety of temperatures:

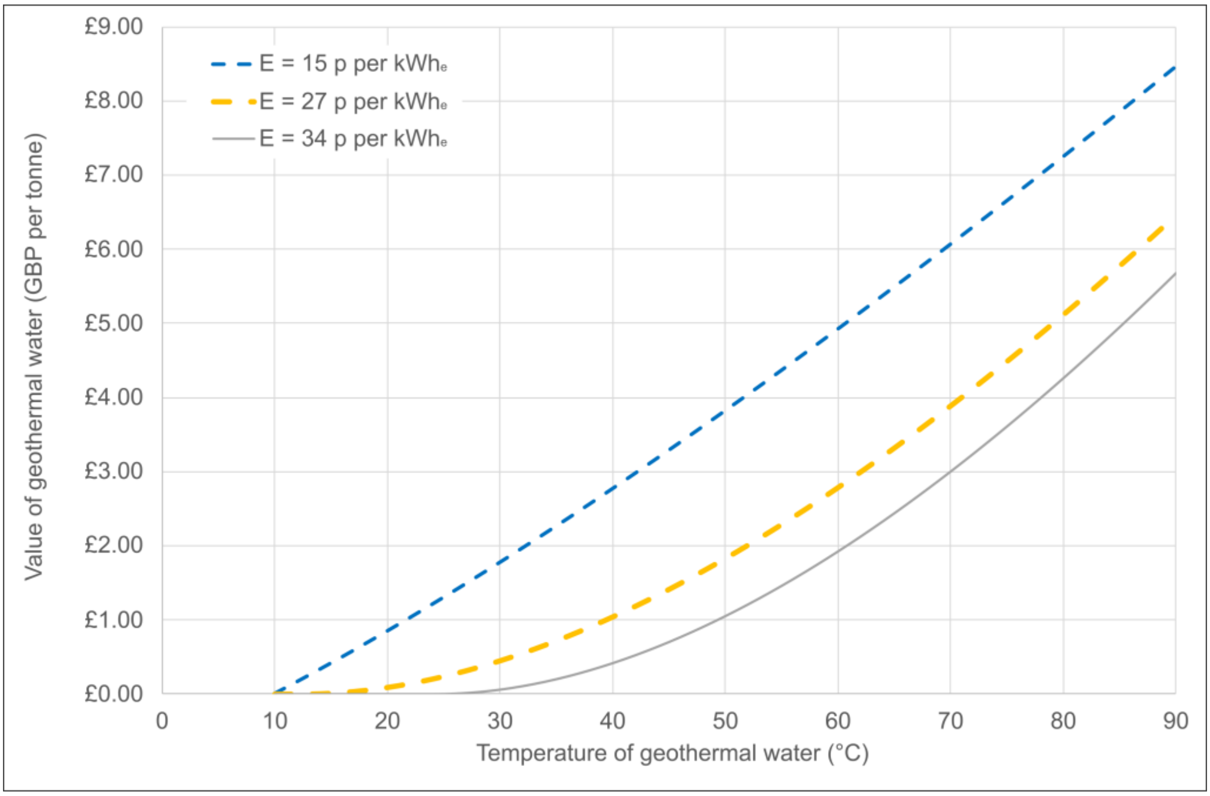

Figure A | The modelled value of 1 tonne of warm geothermal water, assuming a baseline value of waterborne heat as 10 p per kWh_{th} at 70°C; that waterborne heat has no effective value below 10°C; that the heat capacity of water is constant at 1.161 kWh_{th}/tonne/K and that an electrically-powered heat pump performs at 45% of its ideal Carnot efficiency.

The cost of drilling

Drilling costs per metre increase with depth and depend on the nature of the strata and the downhole conditions (overpressure, corrosive, gaseous conditions). Both the American Petroleum Institute (API) and Maciej Lukawski and colleagues (2014) have examined real data and come up with algorithms for estimating drilling costs for a borehole of depth d (in m). These relationships are either polynomial or power laws relative to depth, but in all cases, costs increase faster than depth:

Hydrocarbon wells

Ogden & Johnson (2010) cite the API relationship:

Cost (2005 USD) = $-3.9E{-}08\ d^4 + 4.0E{-}04\ d^3 - 0.84\ d^2 + 903\ d$

Here the cost of a 3 km well is 6.6 times greater than a 1 km well.

Alternatively, Lukawski et al. (2014) suggest:

Cost (million 2009 USD) = 1.65E-05 x $d^{1.607}$

Here the cost of a 3 km well is 5.8 times greater than a 1 km well.

Geothermal wells

Lukawski et al (2014) found a slightly more linear relationship, with costs being greater than hydrocarbon wells at shallower depth, but lower at great depth.

Cost (million 2009 USD) = 1.72E-07 d^2 + 2.3E-03 d -0.62 (Lukawski et al. 2014)

Here the cost of a 3 km well is 4.2 times greater than a 1 km well.

Here I calculate drilling costs according to these algorithms and correct for inflation to 2022 costs in USD (I have used a generic index of inflation, but anecdotal evidence strongly suggests that drilling cost inflation may exceed general inflation):

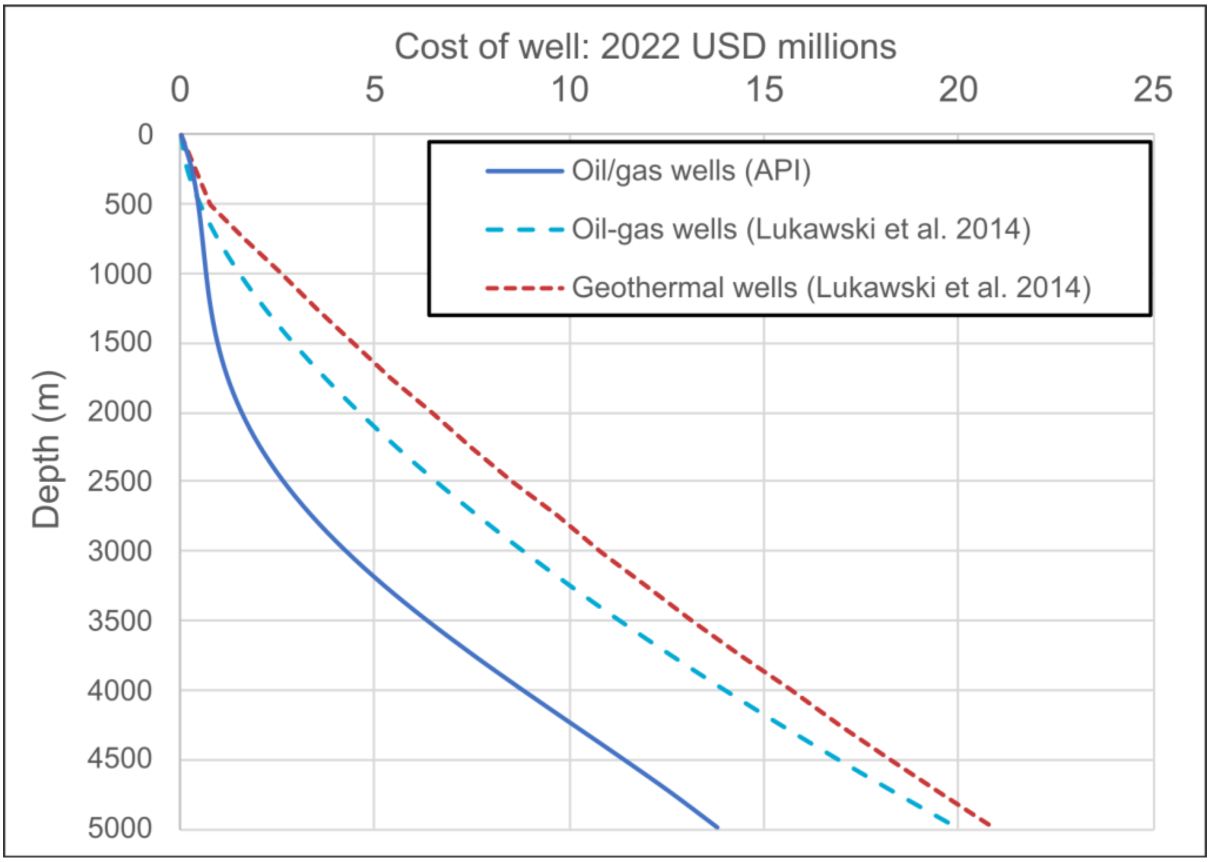

Figure B | The predicted cost of drilled oil/gas wells and geothermal wells, inflated to 2022 USD dollar prices (multiplier of 1.51 from 2005 costs and 1.38 from 2009 costs), based on algorithms provided by the American Petroleum Institute (API) and Lukawski et al. (2014).

Likely fluid yield

The amount of geothermal fluid that can be obtained from a well is approximately proportional to the transmissivity of the formation. That is, the product of the permeability and reservoir thickness.

In fractured reservoirs, fractures tend to close up with depth and permeability decreases logarithmically with depth (i.e. an exponential decline).

In granular reservoirs, such as the Sherwood Sandstone, porosity also decreases with depth. This decrease is partly due to mechanical compaction as overburden pressure increases, but also partly due to pore spaces becoming progressively occluded with cements and secondary minerals (silica, gypsum, anhydrite) with depth. If we ignore the effects of mineral clogging and focus purely on mechanical compaction, a widely respected relationship suggests that the decline in porosity (Ø) is exponential with depth and is related to clay content:

$$Ø = Ø_0 \exp(—d \times [\alpha_0 + X])$$

where $Ø_0$ is the uncompacted porosity, d is depth in km. α_0 is a coefficient of compaction and X is related to the proportion of clay minerals.

But how does the porosity of, say, the Sherwood Sandstone relate to its permeability? So-called “poro-perm” relationships are published for the Sherwood Sandstone reservoir in several basinal settings. The cross-plots typically exhibit a considerable scatter, reflecting different diagenetic histories, cements and sedimentary textures, but there is a broadly log-linear relationship between porosity and permeability (k). In the southern North Sea (Brook et al., 2003), core data show a typical permeability of 1000 mD for a porosity of 27% and of 1 mD for 7% (1 log cycle reduction in permeability for every 6-7% loss of porosity). In the full knowledge that the following estimate is rather crude and ignores a large scatter, this relationship then becomes:

$$\log_{10}k = 0.15\,Ø - 1.05 \qquad \text{(southern North Sea, Ø in \%, k in mD)}$$

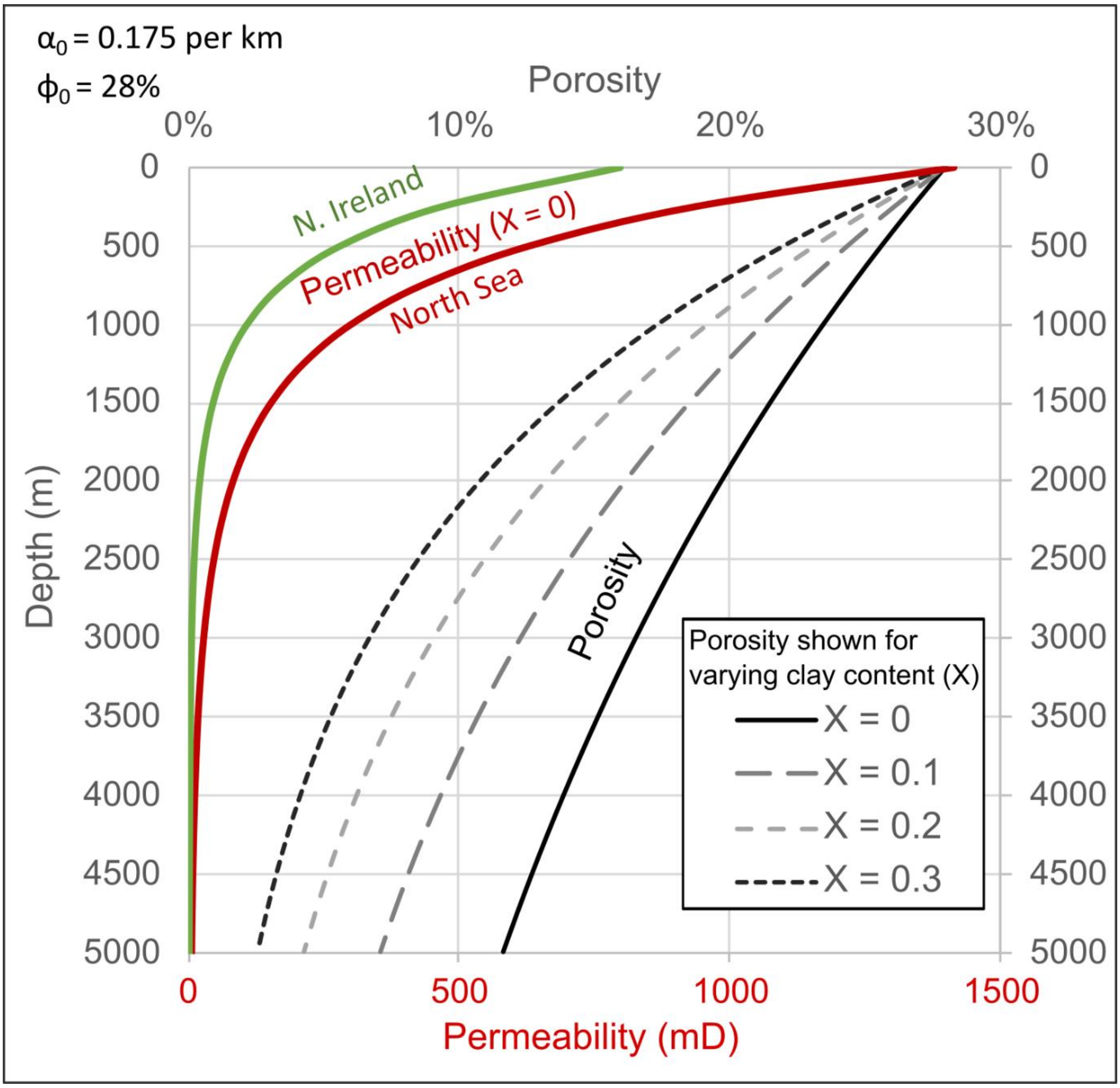

Figure C | Highly idealised porosity-permeability trends with depth. Porosity (Ø) estimates based on a sandstone of uncompacted porosity ($Ø_0$) 28%, with varying clay content (X). Permeability (k) is based on "best fit" poro-perm relationships documented for the Sherwood Sandstone in the North Sea (Brook et al., 2003) and of onshore Northern Ireland (Raine & Reay, 2019), assuming X = 0. α_0 is a coefficient of compaction. In reality, there is a very large scatter of data around these poro-perm trends.

METHODS SECTION | Further reading

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