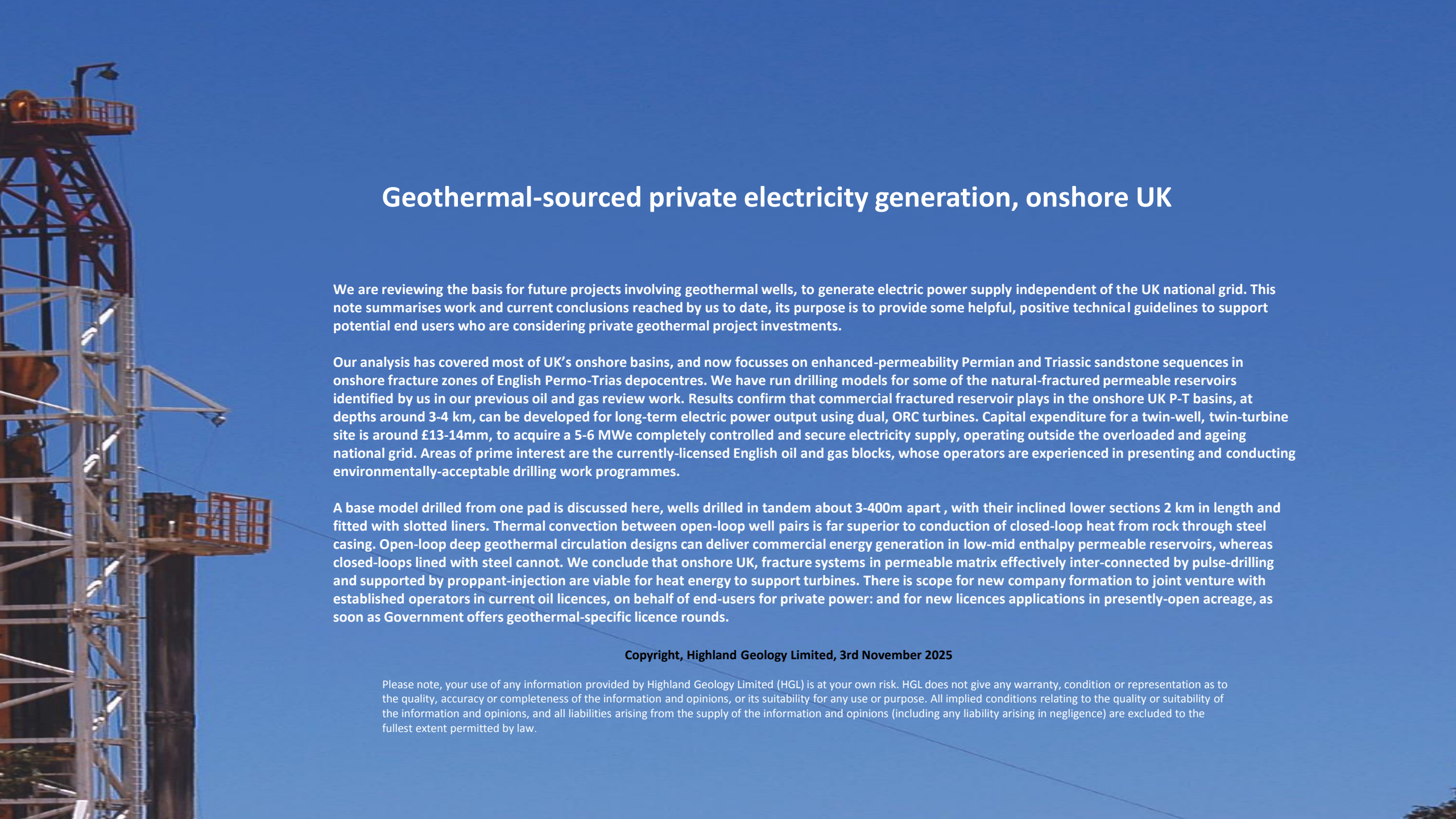

Geothermal-sourced private electricity generation, onshore UK

We are reviewing the basis for future projects involving geothermal wells, to generate electric power supply independent of the UK national grid. This note summarises work and current conclusions reached by us to date, its purpose is to provide some helpful, positive technical guidelines to support potential end users who are considering private geothermal project investments.

Our analysis has covered most of UK's onshore basins, and now focusses on enhanced-permeability Permian and Triassic sandstone sequences in onshore fracture zones of English Permo-Trias depocentres. We have run drilling models for some of the natural-fractured permeable reservoirs identified by us in our previous oil and gas review work. Results confirm that commercial fractured reservoir plays in the onshore UK P-T basins, at depths around 3-4 km, can be developed for long-term electric power output using dual, ORC turbines. Capital expenditure for a twin-well, twin-turbine site is around £13-14mm, to acquire a 5-6 MWe completely controlled and secure electricity supply, operating outside the overloaded and ageing national grid. Areas of prime interest are the currently-licensed English oil and gas blocks, whose operators are experienced in presenting and conducting environmentally-acceptable drilling work programmes.

A base model drilled from one pad is discussed here, wells drilled in tandem about 3-400m apart , with their inclined lower sections 2 km in length and fitted with slotted liners. Thermal convection between open-loop well pairs is far superior to conduction of closed-loop heat from rock through steel casing. Open-loop deep geothermal circulation designs can deliver commercial energy generation in low-mid enthalpy permeable reservoirs, whereas closed-loops lined with steel cannot. We conclude that onshore UK, fracture systems in permeable matrix effectively inter-connected by pulse-drilling and supported by proppant-injection are viable for heat energy to support turbines. There is scope for new company formation to joint venture with established operators in current oil licences, on behalf of end-users for private power: and for new licences applications in presently-open acreage, as soon as Government offers geothermal-specific licence rounds.

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Off-grid, geothermal-sourced private electricity generation, onshore UK

Geothermal is an attractive area for investment on ground-floor terms, offering clean-energy with near-24/365 capability, far superior in this respect to wind and solar, non-hydrocarbon options. Next-generation methods are arriving quickly, and investors entering now stand to gain from early participation. Present UK energy policy is largely electrification-based, intended to meet a carbon net-zero plan impossibly-scheduled for 2030. It is heavily reliant on wind and solar projects, which are supported by guaranteed prices to be met by consumers through various forms of levies and taxation. On top of penal prices, a major issue being addressed by government now is inefficient distribution consequent on the old transmission lines, to get power where it is needed as opposed to where it is generated. Power supply independent of whether the wind is blowing or the sun shining, is essential. To deal with that fundamental requirement, building large battery complexes able to safely store power until line capacity is freed-off, is expensive and running years too late.

Given these inherent limitations, the potential of hot fluid from rocks to drive turbines is obvious as a degree of freedom for UK corporate buyers and utilities. Next-generation geothermal will become the most cost-effective non-hydrocarbon option. Waiting for government to learn, re-orientate, change legislation and set up investment incentives, is to lose opportunity.

We think that next-generation UK geothermal projects will mainly be driven by utilities (wanting to diversify and reduce carbon taxation) and by commercial/industrial customers who will be end-users for <u>projects entirely commissioned and funded under PPA with no intention to make any connection to grids</u>. This latter funding method shortens project time scales and eliminates transmission charges. Project cost estimates for deep geothermal are dropping because of more efficient drilling; better success due to latest quality 3D seismic data and improving interpretation; better well productivity; and supply chains have matured, for items like turbines and ancillary equipment. Alternative clean-energy sources which are full-time available are not seeing comparable reductions. Natural gas for steam turbines, plus necessary carbon capture, have high overheads and significant environmental issues. Small nuclear reactors are not practical in the short term.

For these customers, oil explorers and experienced consultant teams are the critical UK ingredients: oil companies with current licence blocks onshore know local conditions, can get permissions to drill wells, have data bases, can form specialist groups to drill and maintain systems and link with supply chains to establish sites and commission and run the equipment to produce electricity. City investors can choose simply to provide capital for projects, or to invest in services which are of de-risking nature. Geothermal onshore at scale needs skills drawn from the oil sector. In UK, the current oil and gas licensees are the best placed people to move geothermal initiatives, in association with specialists bringing particular skills to project planning. What consultancies like HGL can do, to win business recognition and reward in this market, is focus on reducing project risk: by selling structural geology advice, better understanding of options, better interpretation of data, better well planning. And management services.

Binary-Turbine and Power Plant

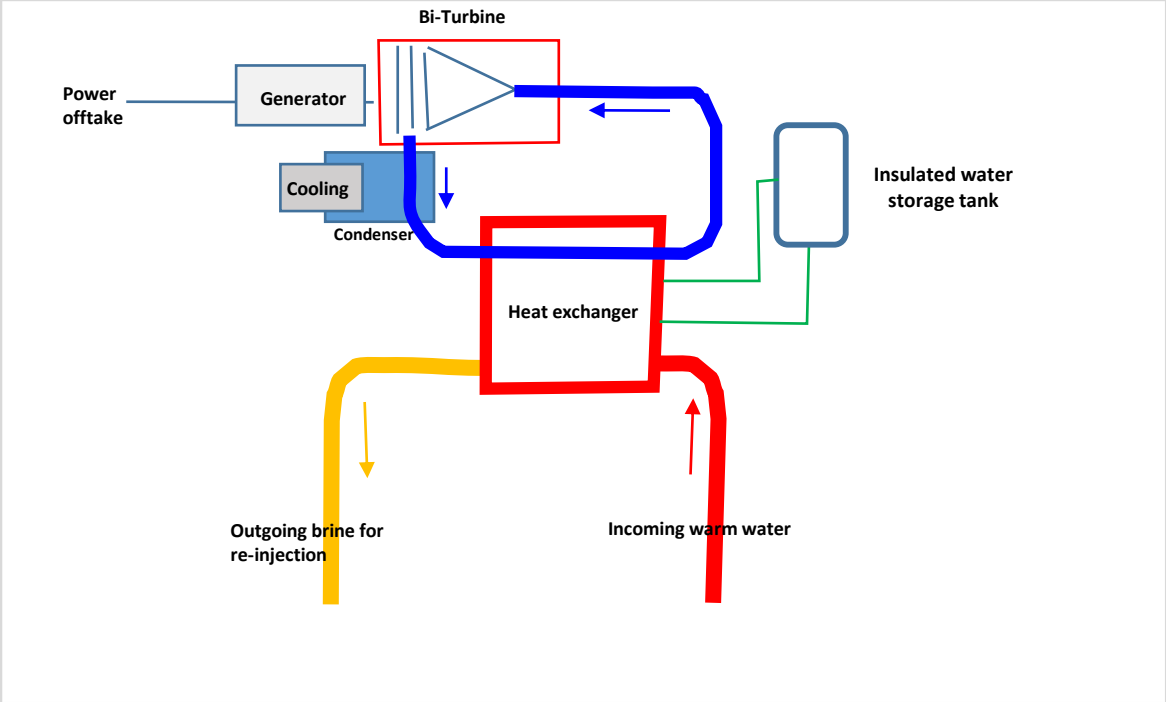
Binary-cycle ORC (Organic Rankine Cycle) power plants are commercial for low-temperature source geothermal fluids. These systems are flexible, modular, and can be run effectively with organic-sourced vapour at heat in range 100-300 degrees C. Presently the efficiency of ORC turbines is lower than that of conventional steam turbines but designs are steadily improving for low-mid temperature applications.

In a binary cycle turbine system the geothermal fluid (red) brought to surface from the reservoir heats the secondary working fluid (blue), typically an organic compound such as isobutane or isopentane. The heat causes the secondary fluid to vaporize, which then drives a turbine to generate electricity. The vaporized fluid is condensed back into a liquid using a cooling system, and the cycle repeats.

Low-temperature geothermal fluids pass through a heat exchanger which contains the secondary, "binary" fluid. This binary fluid is freeze resistant, it's an organic compound, has a much lower boiling point than water, and modest heat from the geothermal fluid causes it to flash to vapour, which then drives the turbines, spins the generator, and creates electricity. The condenser returns the heat exchanger vapour as liquid.

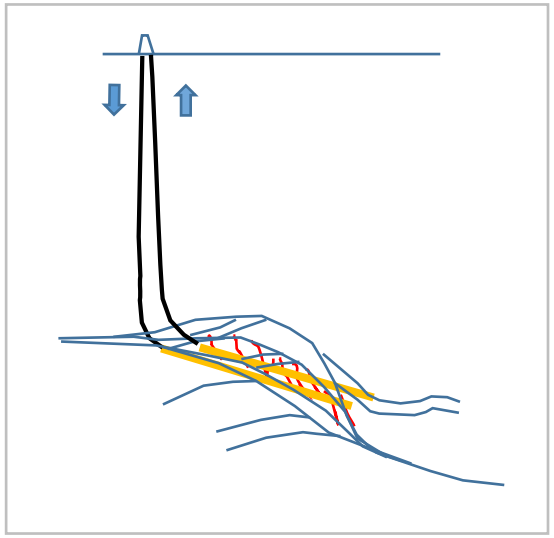
<u>The geothermal fluids never come into contact with the power plant's turbine units</u>. This means high-salinity ground water, any hydrocarbons traces, or corrosive/poisonous gas in solution in the fluid stream go back downhole to safe depth.

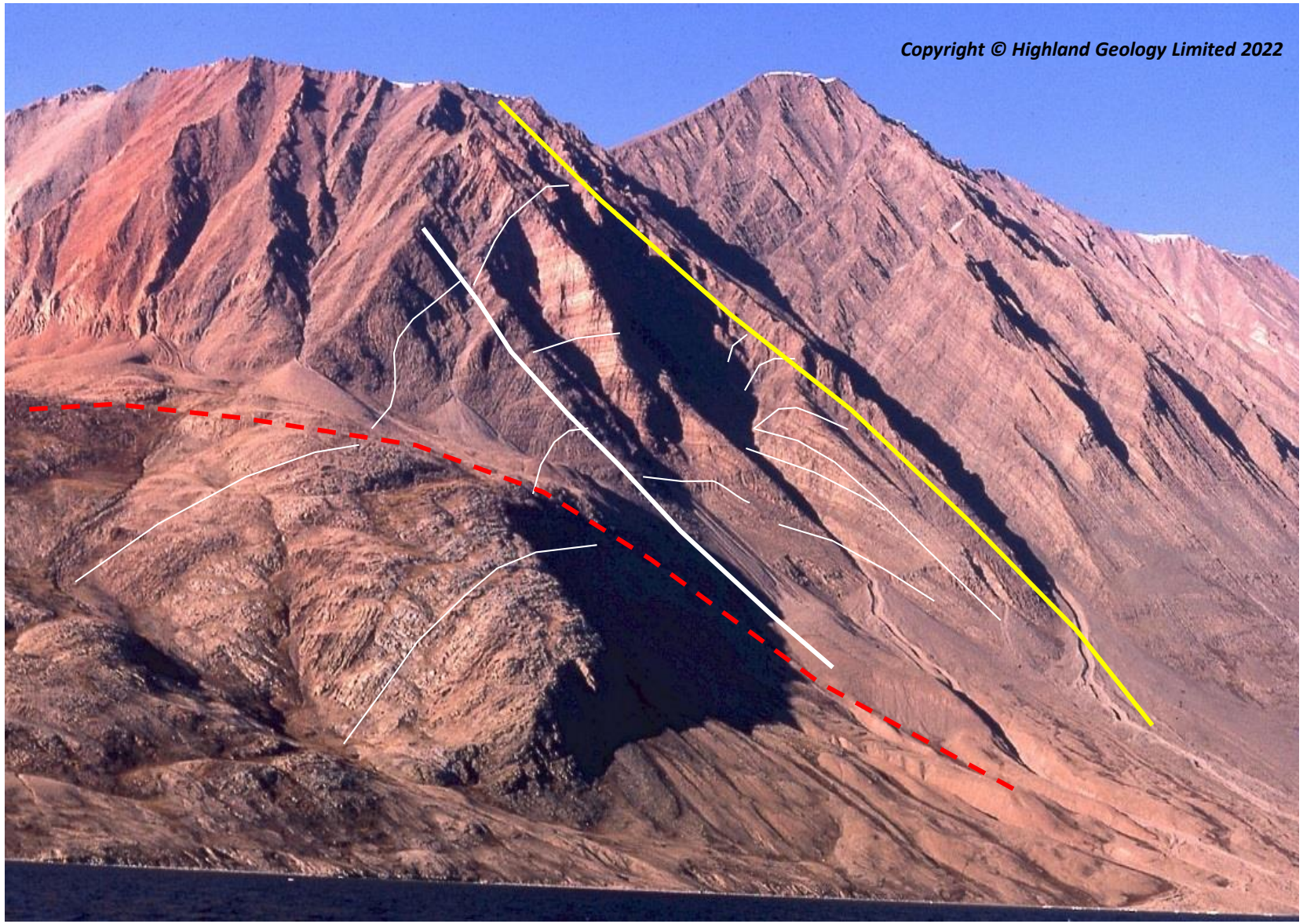
ORC plants can be highly automated. For low-temperature geothermal, efficiency of the heat exchanger is critical as the temperature differential is small. Cooling efficiency is crucial too, and is optimised.



What do fractured rock structures we are targeting look like? They are huge rock slices, called duplexes, and are excellent targets for geothermal drilling

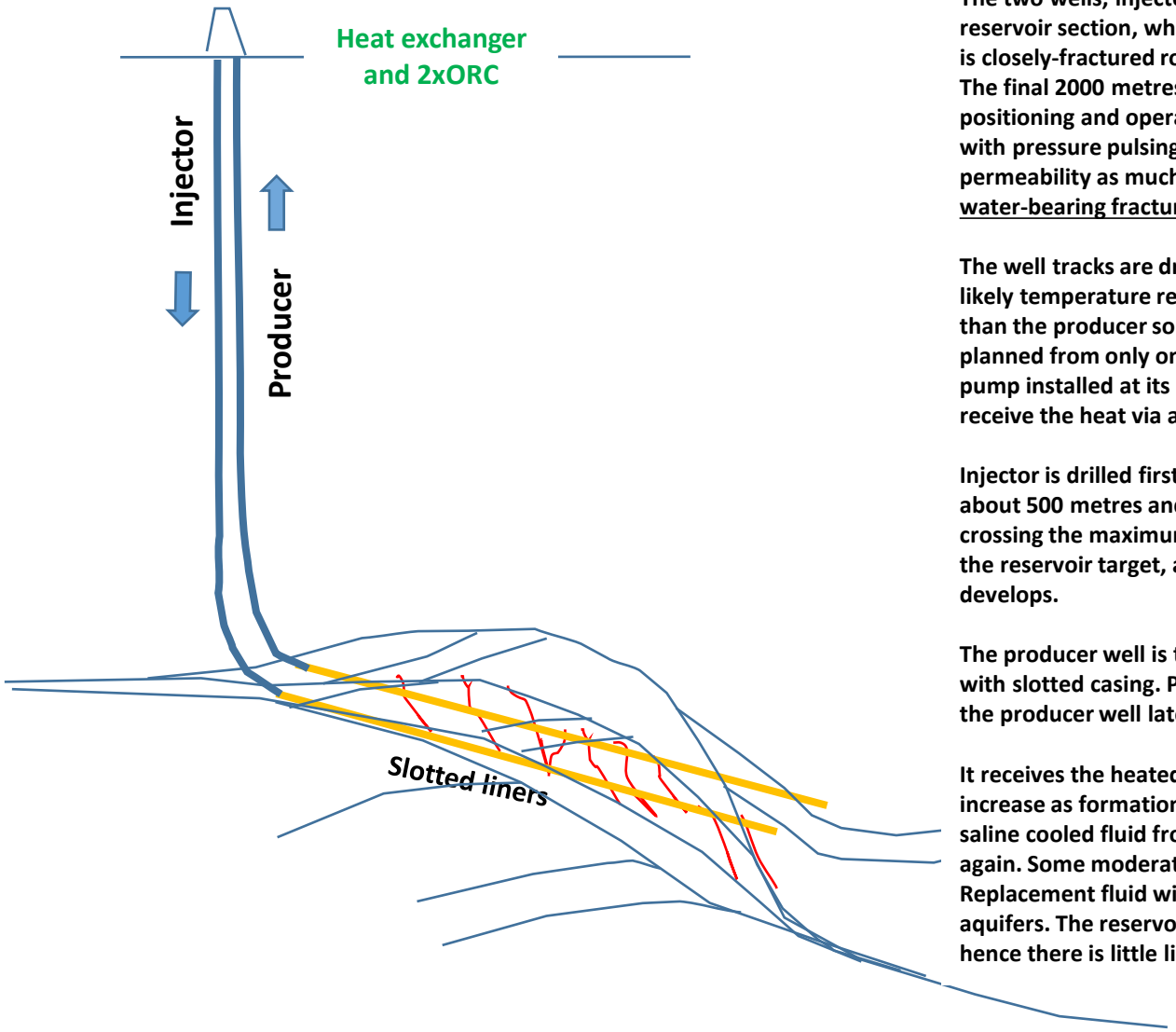
Repeated close-spaced faulting in progressive shortening of earlier extensional structure, forces a stack of thrust slices (duplexes) to develop and progressively climb, each slice stretches as it travels over an upward-convex new fault. The evolving duplex stack will fracture continuously as all previous slices of rock are passively flexed in the inversion. The new faults propagate downwards, each new one's curvature imposes more stretching of the evolving stack above it, because the stack has to stay in contact. Each new footwall collapse fault inflicts its own phase of stretching, and renewed axial fracturing on all of the overlying rock travelling across it. Brittle limestones and dolomites will be particularly likely to fracture.
So we can expect significant opening fractures to develop and thoroughly penetrate the hangingwall. A deviated well pair drilled through the stack will find a high concentration of interconnected faults.





The writer worked on central East Greenland Old Red Sandstone footwall collapse structures, in the late 1960s. This photo shows Rodebjerg, on Ymer O. I like this place: not just for the fascinating geology, I beached a sinking boat here, we stayed alive.

Open-loop deep geothermal twin-well pair with ORC turbines



The two wells, injector and producer, are designed to penetrate a 2 km or so profile through the target reservoir section, which is naturally-fractured sequence at around 3000-3500 metres depth. Reservoir is closely-fractured rock, around 100-125 degrees Centigrade: which means its low to mid-enthalpy. The final 2000 metres are fitted with slotted liners to support the borehole walls and allow packer positioning and operations of various kinds to enhance and maintain the natural fracturing network with pressure pulsing and proppant injection, to keep the main fractures open and improve permeability as much as possible. Rock matrix is a contributory source of thermal input, but <u>it's the water-bearing fractures which are the primary sources</u>.

The well tracks are drilled with separation of about 300-400 metres (150m is the max radius of the likely temperature reduction zone around each one), the injector is maintained at a higher pressure than the producer so that fluid will sweep the zone between the two wells. The well tracks are planned from only one pad, maximising efficiency in drilling operations. The producer has a powerful pump installed at its 13 3/8 casing shoe to lift the hot water to surface, where two ORC turbines will receive the heat via a flat-plate heat exchanger.

Injector is drilled first, its drilled length is about 4000-4500 metres, the 13 3/8 casing shoe will be set about 500 metres and it inclines to a deviated profile to give a final 2000 metres straight profile to TD, crossing the maximum number of fractures at high angle. The final 2000m is cased with slotted liner in the reservoir target, after logging. We aim not to cement the liner except where hole instability develops.

The producer well is then drilled to penetrate the enhanced fractured sequence, likewise it is lined with slotted casing. Pressure differential from the liquid column in the injector pushes hot fluid into the producer well lateral section.

It receives the heated water, circulating at 100-125 degrees C. (Drilling tool performance problems will increase as formation temperatures rise, that's the main reason to set a limit around 125 degrees). The saline cooled fluid from the heat exchanger is flowed to the injector well head and downhole, to cycle again. Some moderate loss of injector fluid will happen, as unconnected fractures will take some of it. Replacement fluid will come from upper sequence formation water: its not freshwater from shallow aquifers. The reservoir system is pressure-balanced and only cools in the vicinity of the slotted liners, hence there is little likelihood of inducing micro-seismic events: all extracted water is replaced.

Conventional geothermal, open-loop wells in fractured rock

What "conventional" means here is two wells initially vertical and then deviated to low-angle horizontal profiles, drilled alongside each other to around 3-3.5 km total vertical depth, one for injection and the other for production, with no direct connection across the 300-400 metre zone separating them. There is no concentric heat extractor pipework in the boreholes, the heat extraction is done entirely at surface (which minimises maintenance cost for removing mineral deposits and corrosion/repairs). We might drill and test two onshore UK simple wells today for £6 million with pad. The programme is designed to circulate and pump high volumes of fluid unimpeded by in-casing equipment: there are just downhole pumps.

In the examples shown below, cross-basin fault zones in permeable matrix (Permian and Triassic) are the project targets, sliced by major natural-fracture systems which contain moderately hot pore water. Minimum for projects using ORCs is around 100 degrees C, but 125 degrees is preferable. Its vital to identify, understand and drill the fracture systems without damaging them, and to enhance their effective permeability.

Occasional open fractures don't suffice: the whole fracture network has to be interconnected. Thermal conductivity is along fractures. There has to be a fluid pressure gradient from injector to producer wells, because free convection only generates weak gradients to drive flow. In conventional open-loop there is no drilling and casing horizontally between the wells; but with slotted liner sections placed, fractured rock is stabilised and allows operations to stimulate fracture interconnection, in the ways which are permitted in UK. Slotted liners have been used in geothermal wells for 50 years.

With this model there is free access of formation water to the offtake well. Improve interconnection of natural fractures by pulse-drilling, and acidise in the case of carbonate cementation. What we can't do (yet) in UK, is frack. But we will be able to inject proppant, as Europa have successfully done recently at Wressle to improve their oil reservoirs in their Carboniferous field there. Proppant is essential, to prevent fractures closing when pressure falls.

Fluid in conventional, simple geothermal well pairs is produced at surface, it expands as it rises up-hole and its density falls, reducing the hydrostatic head, which helps to draw fluid from the reservoir. Using a surface heat exchanger, and then re-injecting the cooled fluid, handling hot fluid is simple and fast. The surface heat exchanger will run efficiently, so the production rate can be high. We don't want to cool the fluid downhole, it increases the weight of liquid being brought to surface. Formation fluids remain contained in pipework at surface and go back downhole. The risk to drinking water is no more than in drilling oil and gas wells.

Risk and EGS

Poor permeability in target rocks is a particular reason why geothermal has remained a poor third option for investment in renewables, way behind wind and solar which are government subsidised under CfD and other forms of end-user taxation. Risk mitigation schemes (insurance policies) are available in a number of European countries investing grants in geothermal: France, Germany and the Netherlands do this, notably, but UK is not supporting geothermal with dedicated licences or grants of any significance at this time. See IEA's 2024 report "The future of geothermal energy", its page 23 has a summary risk-mitigation table. Guaranteed costs in UK until now have run at three-four times the cost of solar and wind power per megawatt-hour, but our models anticipate competitive PPA, power purchase agreements.

In 2020 or so, American projects began to appear with reservoir stimulation designs borrowing from successful oil and gas frack-based exploration. They work, they are the way to execute projects. Enhanced geothermal systems there have focused on fracking to improve permeability between wells, and over large geographic areas hydraulic fracking is accepted by the public, especially those who benefit from wells on their properties. Fracking of poorly convective (or any other kind of) rock is not permitted in UK, largely because of the link between micro-seismic events and hydraulic pressuring by rigs. (We do have earthquakes in UK, mostly minor but Perthshire saw three within 17 minutes on 20th October this year centred on the northeast end of Loch Tay at 3.6 magnitude, depth 5 km, shaking a radius of 60 km, aftershocks are still being felt as we write this).

So, given that we cannot break rock to improve permeability, our model is to drill already heavily-fractured fault trends, seen on seismic profiles and mapped using 3D seismic profiling. The presumption is that at least some major through-going faults are still open. A potential problem is that just a few important fractures may be dominant in the 2 km sample section, mainlining injected fluid from injector to producer wells before the fluid efficiently collects heat from the broken matrix. We address this by the drilling method. Intermittent pressuring and pumping re-opens and re-connects fractures around the well bore. Think about a chocolate orange. What happens with intermittent pressuring is an annular fracture bundle forms around the well bore, it's a disposal domain with a series of vertical fractures radiating off from the well bore, they have slightly different angles around the bore, giving slices like the pieces of chocolate in the orange. As you go on pushing drilling fluid into the receiving formation, the micro-fractures grow horizontally and the space for water storage increases accordingly. The volume available becomes far bigger than simple models predict. It's not a big fracture plane: it's a large number of sequential micro-fractures. We can inject proppant materials to prevent the fractures closing again when the drilling pressure is reduced to normal.

For a borderline permeability case there is the option to drill the wells deeper, adding say another 500 metres apiece. A second injector can also be drilled. Well trajectories are very important, they have to cross the main fractures at high angle.

Quantify potential production from rock matrix: method

This following analysis comes from GRC Transactions, Vol. 45, 2021, "A feasibility study on three geothermal designs: deep closed-loop (with and without conductive fractures) and open-loop circulation between multi-fractured laterals", by Garrett Fowler and Mark McClure, Resfrac Corporation. In our opinion its one of the most important papers written on geothermal science and future development, in the last half-decade.

Quoting them, "Thermal conduction into the wellbore is mathematically identical to the equation for single-phase flow through a hydrocarbon reservoir. We replace pressure with temperature, φc_t (porosity times compressibility) with ρC (density times heat capacity), and k/μ (permeability divided by viscosity) with K (thermal conductivity). Rearrange the equation to calculate the <u>heat production rate that would be required to achieve a specified thermal drawdown over a specified period of time</u>". The equation becomes:

$$Q_t = \frac{4\pi K h \Delta T}{\ln\left(\frac{Kt}{\rho C r_w^2}\right) + 0.80907}$$

Qt = flow (energy extraction) rate, and it's <u>thermal</u>, in megawatts thermal MWth. It's the heat production rate which is required to give a specified thermal drawdown over a given time . Multiply by 0.15 or 0.1 to convert to megawatts electrical MWe.

K = thermal conductivity in W/(K-m); its equivalent to permeability divided by viscosity
h = operational length of the production lateral, in metres
r sub w = wellbore radius in metres e.g. 10 cm is 0.1
Delta T is the desired thermal drawdown over specified period of production (say 1 year), its units are degrees Centigrade
rho ρ = rock density in kg per cubic metre, (kg/m3)
C = heat capacity. pC is density times heat capacity.

Let's now run a model, using variables appropriate for a unit like Collyhurst Sandstone in the Permian, appropriate for east Cheshire Basin and in Lancashire near Preston.

The importance of fractures in heat production

For the case of a Collyhurst sequence exemplified at Knutsford-1 well, on the east side of Cheshire Basin, lets apply an effective production lateral of 2000 metres; wellbore radius is 0.1; sandstone typical density is 2650 kg/cubic metre (it varies a lot, in practice; heat capacity is 1500 J/(kg-K), sandstone there likewise varies widely, e.g. between 800 – 2000).

What figure should we use for K? For matrix, a number like 3 would be reasonable - but we are modelling a fractured sandstone, not matrix. An estimate more like 7 would be reasonable.

If we wanted to draw down heat at a high rate over the first year of production from the space between the laterals, by say 100 degrees C, use that for delta T (the reservoir temperature would of course be renewing, so it wouldn't get anywhere near this figure at the year end); the thermal power drawn in one year could then be about 1.9 MW thermal.

$$Q_t = \frac{4 * \pi * 7 * 2000 * 100}{\ln\left(\frac{7 * 365 * 24 * 3600}{2650 * 2000 * 0.1^2}\right) + 0.80907} = 1.924 \quad MWth$$

We might possibly find this amount of thermal energy useful per annum, but it isn't going to pay back the cost of two wells with large laterals and the same sort of cash again for ORC and generator. Given that electrical MW power output would be one tenth of the thermal figure, the result is not commercial. This order of output is what has led operators in other areas to drill to 5-6 km depth for 300-400 degrees C reservoirs, and 7-8 km length of laterals, pursuing uneconomic solutions needing large grants of Government cash (which comes from tariffs on electricity bills). And its what has led to minimal investment in low/mid-temperature geothermal projects, despite the recognition that the deep heat resource is enormous.

But…….. let's see what addition natural fractures can contribute.

Totally different: heat production from fractures is commercial

This again comes from the excellent work of McClure and Fowler: they give this equation, "Let's assume that there are 500 flowing hydraulic fractures connecting the injector and producer; the well separation is 300 m, the fracture height is 200 m, the fracture conductivity is 50 md-ft (1.52e-14 m^2), and that the water viscosity is 0.15 cp; the bottom-hole pressure at the injector well is 5 MPa greater than the bottom-hole pressure at the production well. Then, assuming 1D flow, from Darcy's law, the <u>energy production rate</u> will be":

$$Q_t = \frac{NhC}{\mu D} \Delta P \rho H$$

where *N* is the number of fractures, *h* is the height in metres, *C* is the hydraulic conductivity of each fracture (the product of fracture permeability and across-fracture width, in md ft converted to SI), *D* is the separation between the wells, ΔP is the bottom-hole pressure difference between the wells, μ is the viscosity, ρ is the fluid density, and *H* is the specific enthalpy of the fluid.

JN modifies their figures which were for 200 degree reservoir. At 100°C, the density figure will be around 880 kg/m^3, and liquid enthalpy of water will be around 400 kJ/kg. Plugging in the values:

numerator = $(500*200*1.52e{-}14) * 5)$ = 7.6e-10
denominator = $300*(0.15e{-}9)$ = 4.5e-8
divide through and multiply by fluid density and specific enthalpy gives
0.01689∗880∗400

and so Qt = 5945 kWth or 5.9 MWe

At 10% efficiency of conversion to electricity, this would yield 5.9 MWe. At 150 degrees C, the H value is about 600: so the figure for energy production given here is a conservative one.

The matrix contribution is of some minor value, then, but efficiently linked and numerous fractures deliver an electricity-generating project and profits. <u>This means we can go to Mesozoic targets onshore UK, and also drill into strongly-fractured Carboniferous basins as well, so long as there is 100-plus degrees Centigrade temperature and effective permeability from fractures</u>.

The cost of a proving test, to include turbine-running

In £ millions	
Open-loop wells 300m separated, latest US drill style, with slotted liners 2 km length, and flow tests	
To map,plan and drill 2 4km wells and flow test, evaluate, costs £13mm	
Buy available 2D seismic, shoot 3D	2
Reservoir studies, system design	1
CAPEX drilling and completion, test wells	
Rental of one site (possibly end user would supply)	0.5
Build 1 pad, access roads: 3-cellar site	1
Injector well drilled 4000m length and slotted liner	3
Producer well likewise, parallel to injector, 300m	3
Stimulate reservoir fractures, acidise, well tests	2
Large insulated tank for hw storage	0.5
Pumps, 2, lease	
	13
Given successful testing, rig down and rent ORC and support surface equipment, add £1mm	
ORC 2.5 Turbine, 1 unit, lease	
Generator, lease	
Heat exchanger, condenser, lease	
Variant: acquire lease to deepen two existing wells by 2000m apiece; saves maybe 4mm? and tests reservoir at 150-200 C: reducing risk of low flow rate.	
Given successful testing, rig down and rent ORC and support surface equipment, add £1mm	
On success, add capex for another ORC, begin sales; or hand over to subscriber	

1. This spreadsheet suggests the initial target sum wanted is around £2-3 million to acquire and map seismic to confirm target, and to reprocess or infill data to confirm fracture patterns and finalise possible spud locations.

2. To perform well design, drilling and testing of a well pair using prices based on lessons from US operators, the sum wanted to drill the two wells - to log, extensively test, and complete for installation of ORC equipment on lease terms - is (roughly) about £10 million. This covers acquisition of the site on lease; build access and three cellars for the two wells; drill and run slotted liner in the injector; skid the rig for the producer, and drill that. Then set up surface facilities for production testing, that equipment will all be leased until the result is known to be commercial. The rig is released for extended testing, replaced with a hoist.

3. When the production rate is confirmed, one ORC turbine and support items can then be leased, and if all that equipment runs successfully, the site is proven and can be retained to supply power: at contract stage or end user buying the whole project, buy the surface equipment and add a second ORC turbine.

To get to spud-in day for the first well, will take about 1 year because permissions are needed from dozens of interested parties, and whilst that process is happening a consortium can raise the remaining project capital, along with the team who will provide the technical skills and logistic support.

If the injector well could be deepened in the pattern we show and reach 125 degree reservoir, that's a sizable potential saving on the injector. That money subsidises the deeper drilling and reduces risk of sub-commercial heat flow. Oil and gas operators will be fully aware of this approach to geothermal entry.

How much revenue can a geothermal well pair generate?

The mid July publication of Government's 2025 renewables Administrative Strike Price subsidy figures for power supply (the Contracts for Difference update) has confirmed that onshore and offshore wind, along with solar, are about to be more expensive than burning natural gas in turbines, despite the tax loading on gas. For summary and comment on these latest numbers see Kathryn Porter's blog, discussing ASPs for the current AR7 auction, in Watt-Logic, 27 July 2025.

There is no inclusion of geothermal yet in the plan for meeting the Clean Power 2030 targets, and in the following model we choose figures which match the onshore wind price per megawatt hour. CfD weighted-average for AR6 had onshore wind at £89 per MWh. For a 15-year period now, the current AR7 ASP for onshore wind is increased to £103, which is about 12 percent higher, results of the auction are expected in late 2025.

So let's say we are running an ORC turbine putting out 2.5 MW for 8760 hours per year, allow 90 percent capacity is achieved, that gives us 19710 MW per year. Valuing this at the AR6's £89 per MW gave that single ORC revenue stream at around £1.44 million, with 2024 rates.

Re-run now at £103, points to £2.03 million. If we are operating two ORCs, an annual revenue stream at around £4 million is therefore attainable, and that is the basic more or less minimum figure used in the following model. Its just a guide, to roughly indicate what order of income is plausible for the model used.

Actually, we are not recommending CfD as the basis for commercialising early geothermal projects. <u>PPA is likely to be higher than CfD, or wholesale market prices</u>. Long-term PPA power purchase agreements will provide more stable and predictable income, and depend on negotiation: sole off-takers will be prepared to pay a premium for security of supply per well, or will buy the entire project outright.

2025 cash flow entry-level model for an open-loop 5 MW well pair with slotted liners

In £ millions																					
Year	1	2	3	4	5	6	7	8	9	10		11	12	13	14	15	16	17	18	19	20	
Open-loop project twin-wells with slotted liners																						
Phase 1: to map,plan and drill two 4km wells and flow test, evaluate, costs £13-14mm																						
Rental of land (possibly end user would supply)	0.50	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25		0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	
Buy available 2D seismic, shoot 3D, process for fractures	2																					
Reservoir studies, system design	1																					
Build 1 pad, access roads:3-cellar site	1.5																					
Injector well drilled 4000m length and slotted liner	3																					
Producer well likewise, parallel to injector, 3-400m apart	3																					
Pressurise reservoir fractures and inject proppant, well tests	2																					
Large insulated tank for hw storage	0.5																					
Lease 2 large pumps	0.2																					
	13.7																					
Phase 2: Given successful testing, rig down and rent ORC and support surface equipment, lease £1mm																						
ORC 2.5 Turbine,1 unit lease plus ancillaries	1																					
Generator																						
Regenerator, for second pass (cascade)																						
Heat exchanger, condenser																						
	1																					
Phase 3:																						
Connect to grid (periodic?)	1											1										
Year 2, buy surface kit plus second ORC		4.5																				
Capex and Opex spend (exclude management charges	16	5	1	1	1	1	1	1	1	1	29	2	1	1	1	1	1	1	1	1	1	40
SALES OF ELECTRICITY and HEAT		4	4	4	4	4	4	4	4	4	36	4	4	4	4	4	5	5	5	5	5	81
NET ANNUAL POSITION pre-tax	-16	-17	-14	-11	-8	-5	-2	1	4	7		9	12	15	18	21	25	29	33	37	41	

Possibly, the purchaser is a behind-fences data centre or military, airfield, factory complex needing guaranteed self-owned power supply, and will pay premium relative to wholesale market.If so, the land rental may be zero.
Altogether different is a district heat project, part funded by government grant, paying on a market-defined basis. Heat sales require pipeline capex.

The well-pair design makes significant cost savings: one pad only; the rig slides on rails from well one to two, only 20 metres from cellar 1 to 2, saving £1 million demob and move several km, set-up; there is no pipeline needed to return cooled water from the heat exchanger back to injector well; rig time is saved on second well as its track is almost identical to first well.

Example 1. Open-loop slotted liner well pair: east side of Cheshire Basin

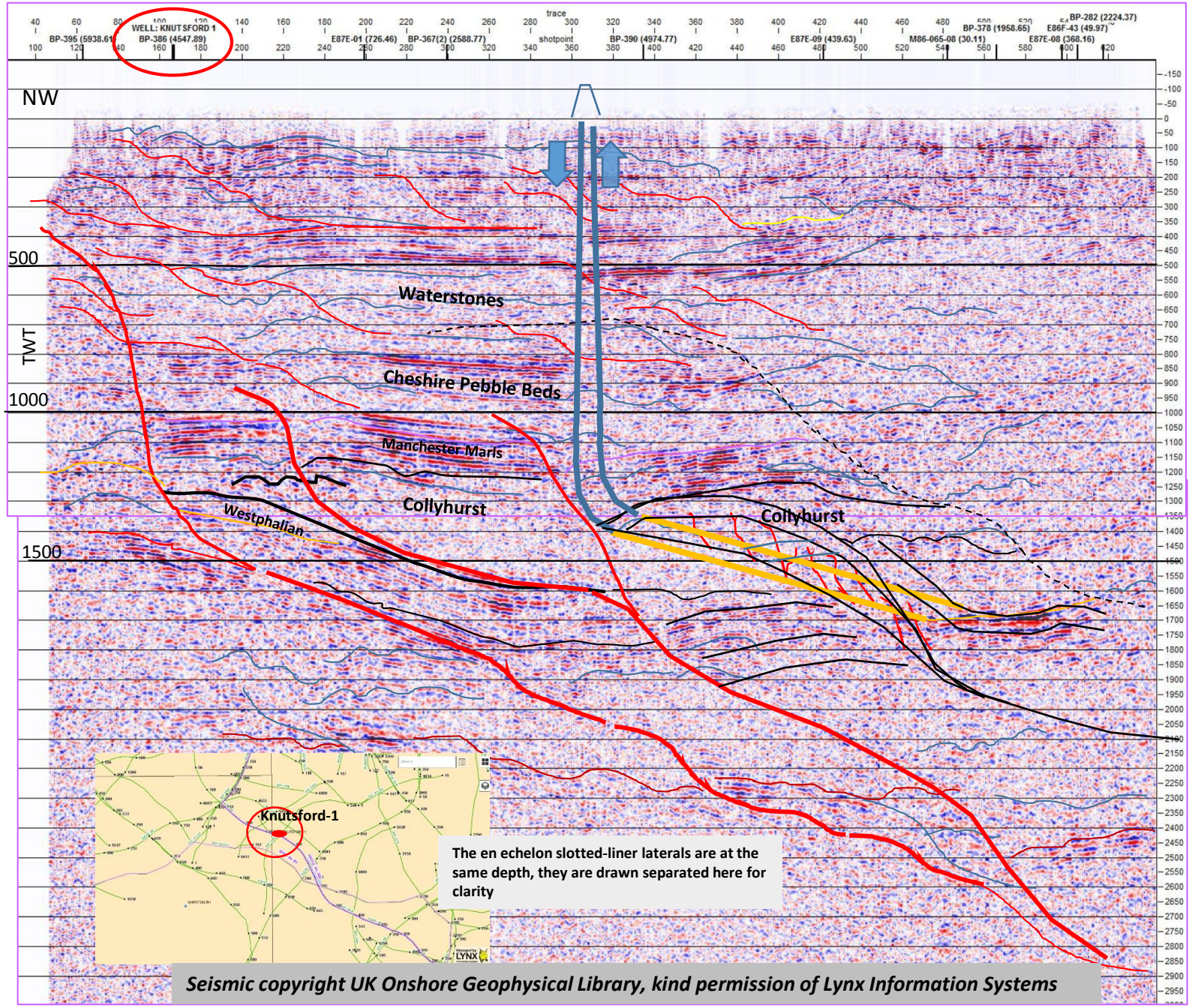
This instance, is in open acreage. Potential end-users here are district councils which plan town-centre heating schemes. Knutsford-1 area (ringed in red) drilled for hydrocarbons in 1974 is one possible re-drill location, to go deeper with a design like the overlay. The heating sequence is the Permian Collyhurst Sst at around 2750-3000 metres with backup from younger Triassic sandstones. CS is folded and faulted at the zone where Manchester Marl is broken, promising high fracture permeability as well as good porosity in thick sandstones.

Learning American lessons, we might drill the two wells for around £5-6 million, if there is good seismic control. The second well will be less costly than the first one, as the sequence is then known in high detail and bit selection etc will be more efficient. K-1 didn't have problems except tight hole in top Triassic thin salt sequences, its in the Cheshire salt depocentre and required high salinity mud at spud. The upper Triassic saline beds above Waterstones will be a source of fluid for the programme, saves buying fresh water. No hydrocarbons were found at K-1, which helps the drilling approval application.

Capex all-up £14-15 mm to confirm target, shoot 3D, design, drill, test and complete, get into service year 1, followed by the second ORC and outright purchase of all surface plant, is a reasonable projection.

There is potential to drill another well pair immediately to the northwest, given success with the first pair.

In this seismic profile the scale is 1 second approx. 2500 metres depth, 500 msecs approx. 1000 metres. Zero time is approx mean sea level.



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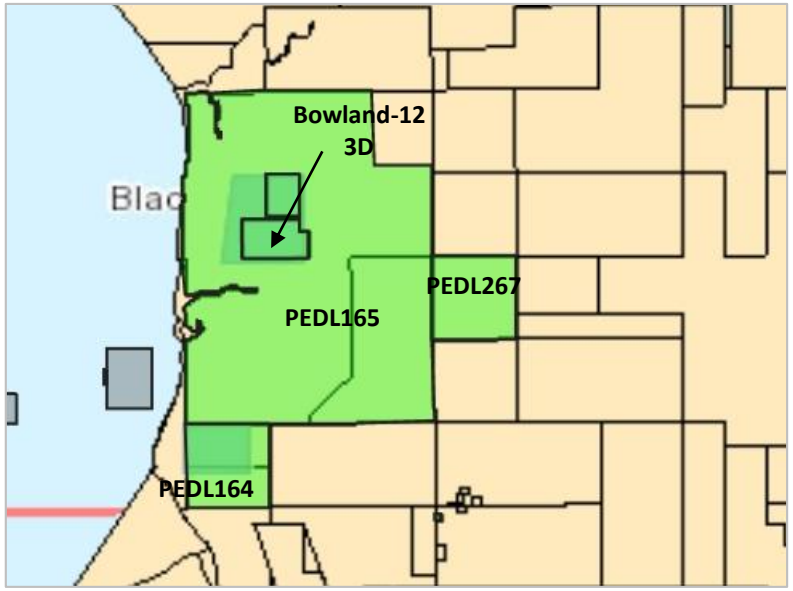
Second example: PEDL165 Preston-Blackpool-Formby area

In our second case, three hydrocarbon licences in the Bowland Basin are current (green areas) and have moderately deep Permian fractured reservoir. Darker-green areas are 3D survey coverage shot, for shale gas. Wells here can be classified and drilled under the oil and gas licence terms, given an agreement with the operator on charges and equities.

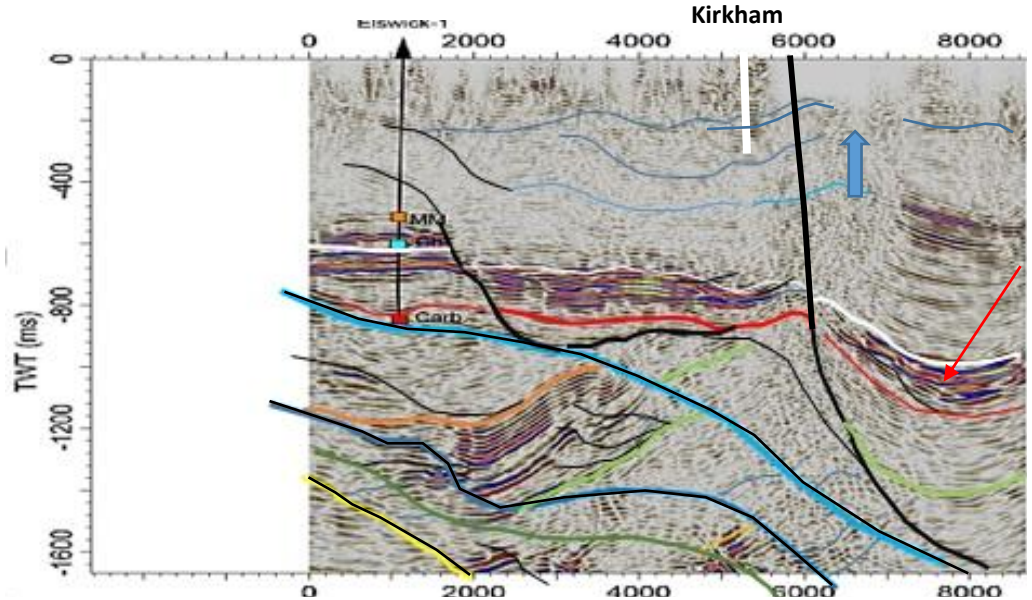
Two areas of particular interest for drilling in a pilot project are Warton airfield near Preston (next slide), and the shale-gas wells area tested by Cuadrilla which have been suspended since micro-seismic events led to termination of fracking in UK. In the case of the Warton area, that is in PEDL165 and could be drilled under agreement with Cuadrilla Bowland.

In the shale gas wells, maybe at the last minute those two wells might be re-assigned to geothermal use rather than enforced-abandoned?



In PEDL165, north-south orange line in the map is seismic (shown below) from the 3D coverage area in the blue-outlined rectangle. The profile passes through the Kirkham borehole, which was drilled only to 450m to investigate a possible salt structure for fuel storage. The breakdown of seismic continuity on the fault just south of the borehole may suggest a possible water escape plume from the Carboniferous, blue arrow, though note there is a big loss of seismic fold at surface.

We think Kirkham fault is an important inversion fracture zone, marking footwall collapse faults on the north side, it's an extensional sidewall on the down-to-west fracture trend bounding the complex of local PermoTrias-infilled basins, one of which is the Ribble Estuary Graben, reversing in compression in early Permian and again in Alpine plate tectonics. The following slide is red-line IELP-99-07 and we mark a possible well pair to reach down-faulted Collyhurst Sandstone at around 1400 msecs on that profile, ie about 3000 metres. Collyhurst deeper than that could supply two ORC turbines to generate 5 MWh power and heat for end-users such as the British Aerospace factory (circle, dashed).



Collyhurst Sandstone at near 2 km on north side of airfield: and possible hot water escape through fracture zone to Kirkham borehole

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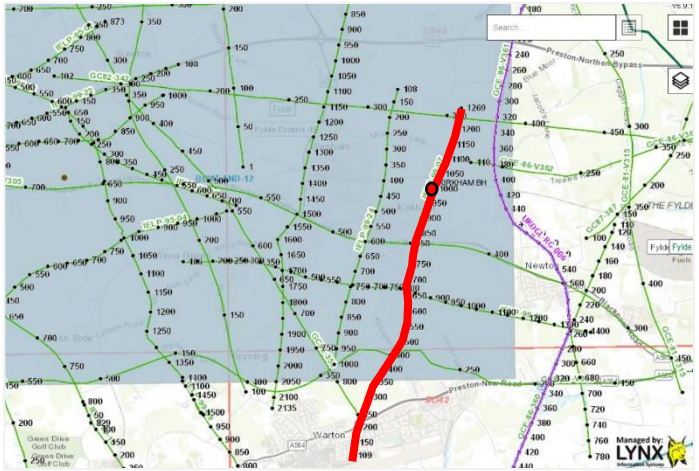
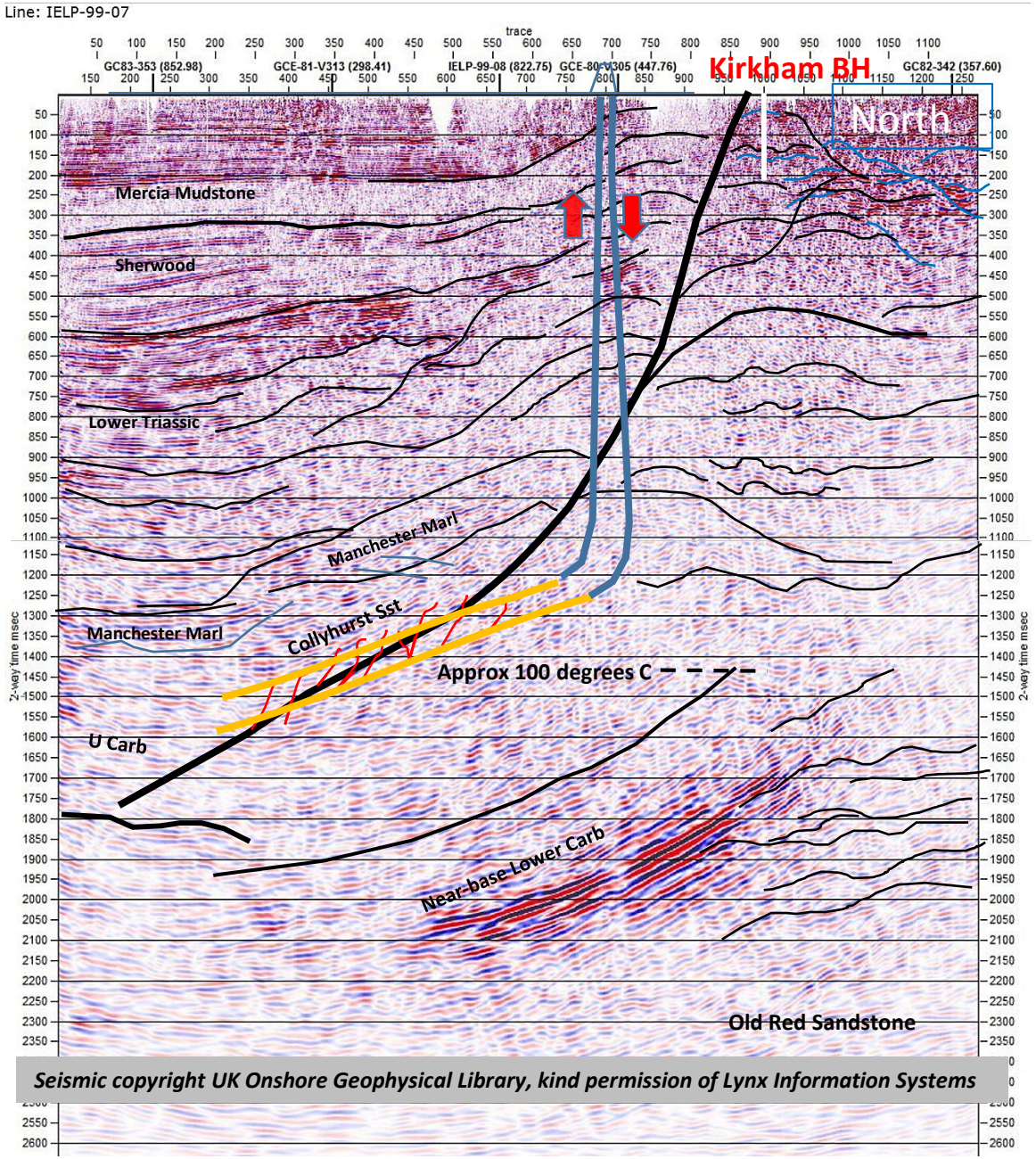
Map is top of Sherwood Sandstone, from UKOGL Independent report of 2019. Purple lines mark Ribble estuary shorelines. All the map area lies inside PEDL165.

Line IELP-99-09 open-loop pair with slotted liners, reservoir in Collyhurst Sandstone

In this 1999 seismic profile. shot by then-operator Independent, the scale is 1 second approx. equivalent to 2000 metres depth, 500 msecs is approx. 1000 metres. Laterals for the suggested boreholes are in Collyhurst, TVDs around 3000 metres. Line length is 5.8 km.





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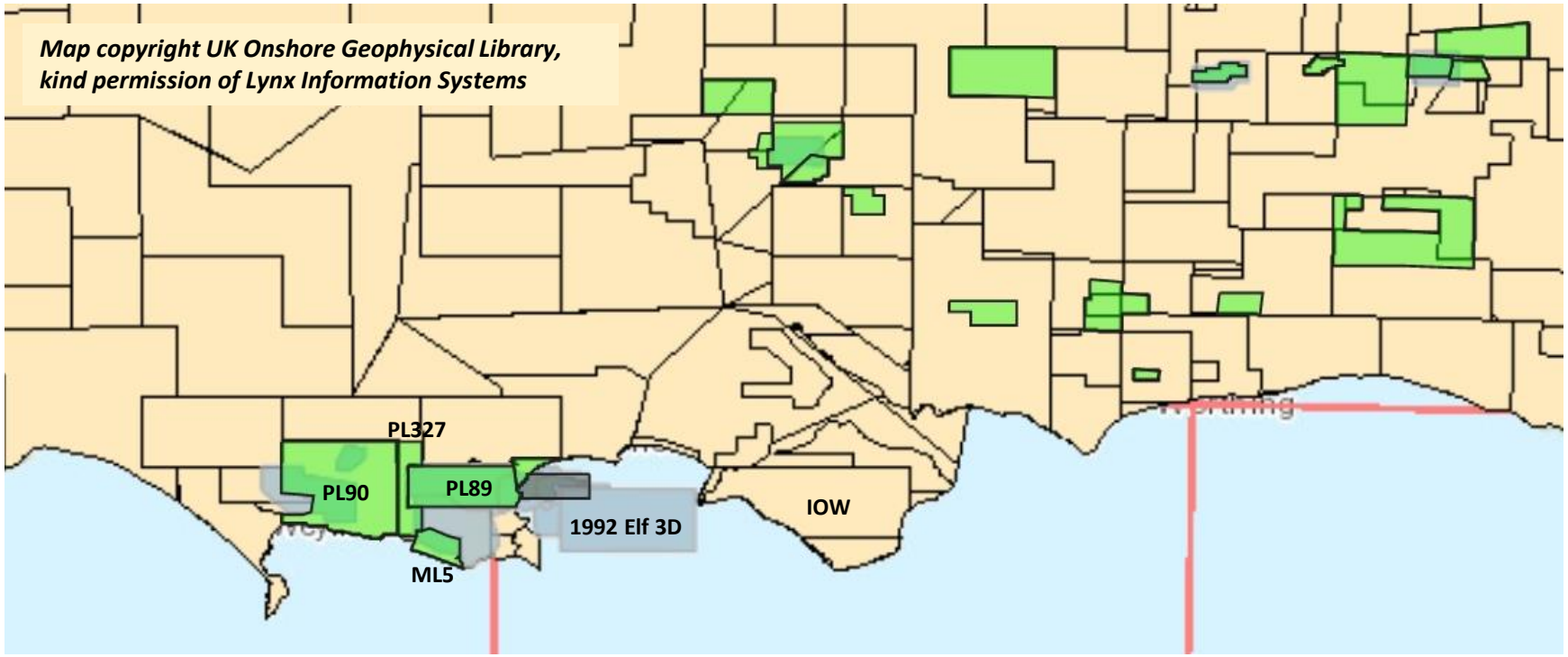
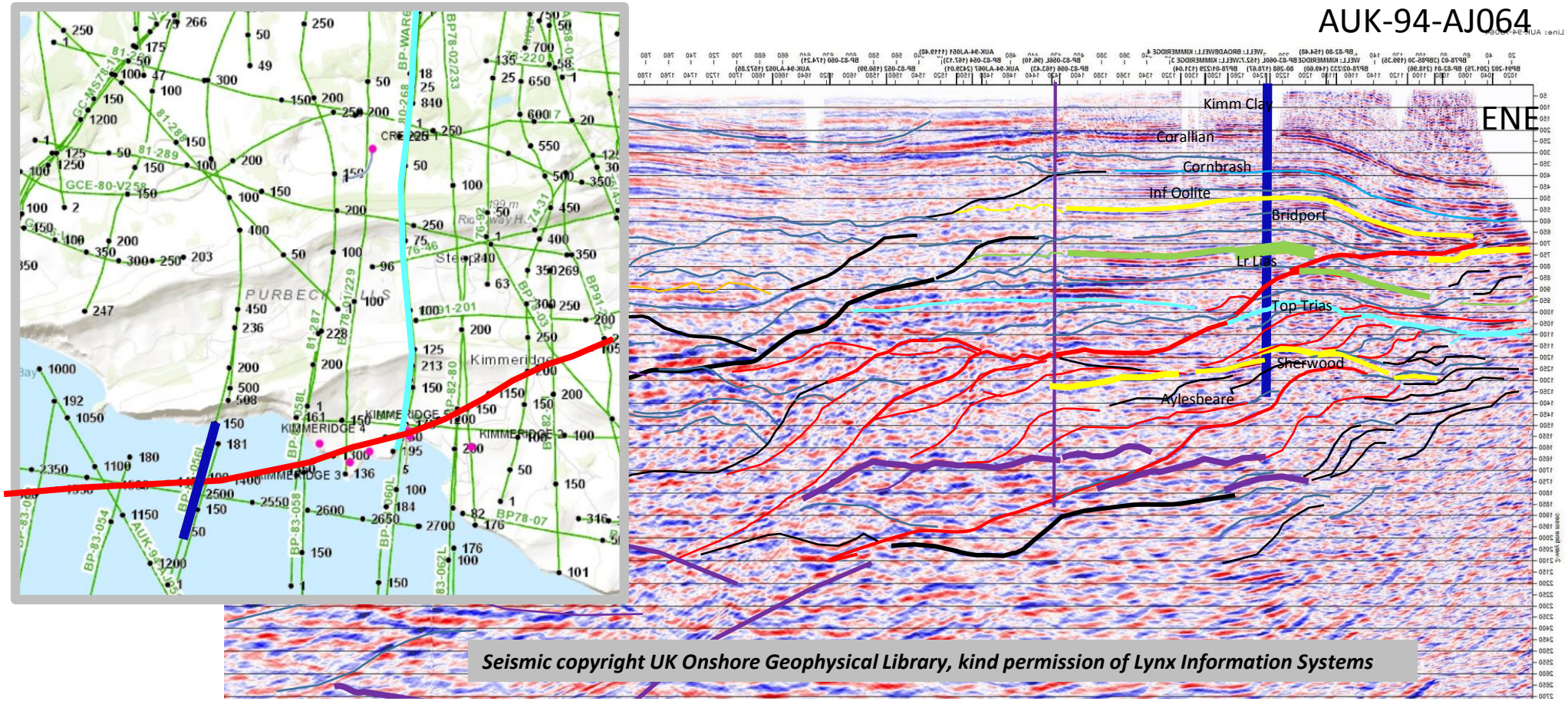


For a third Trial Project location, specifying fractured Permian and Triassic reservoirs at significant depth, in southern England the hydrocarbon licences in green between Weymouth and onshore Wytch Farm are still current. Grey areas show 3D data cover. This is prime acreage for geothermal exploration. Orange inset is the licence administrator and beneficial group breakdown for the green areas. The next two slides show structure style typical of progressive inversion along the trend.

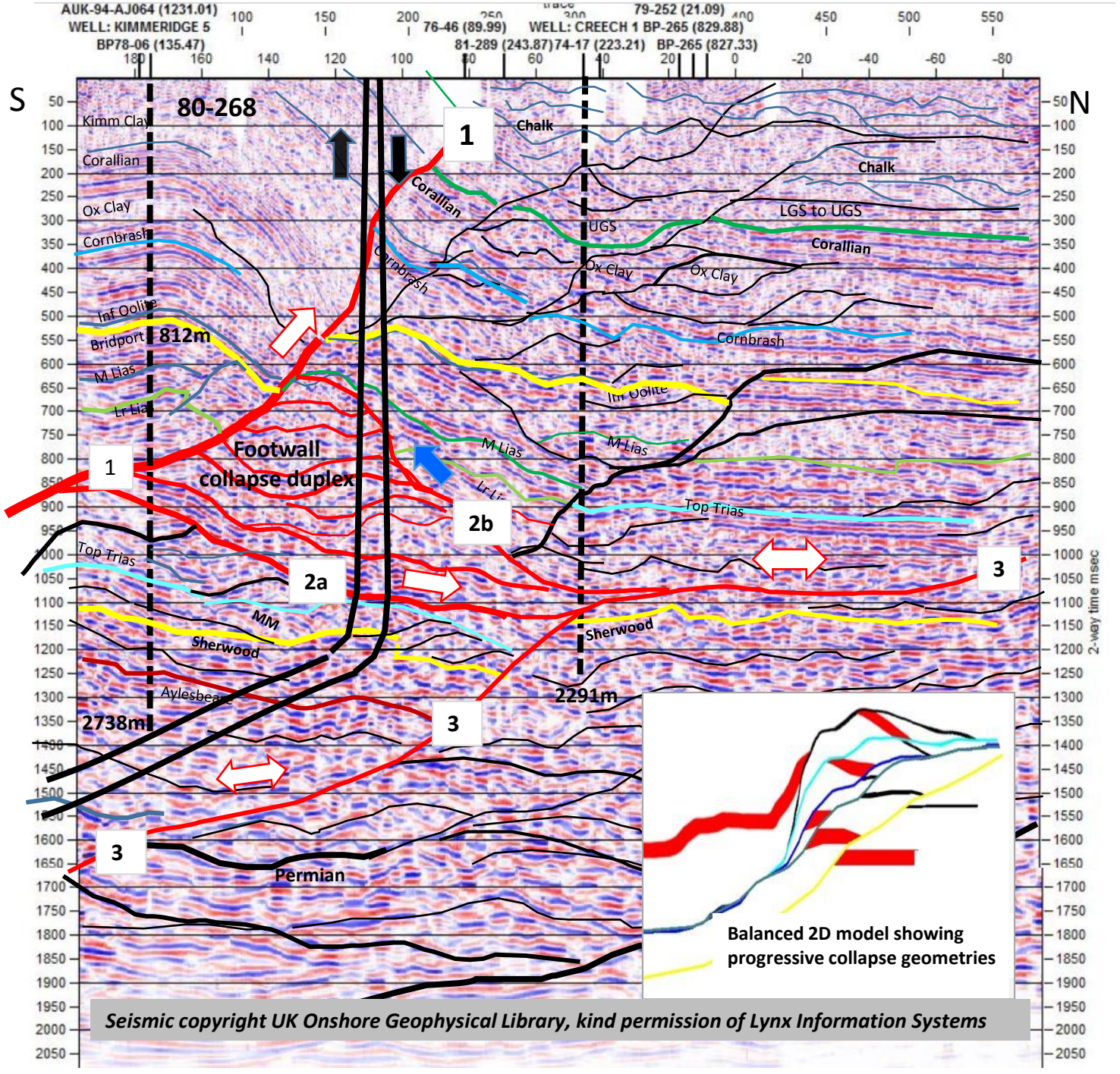
We have Kingdom mapping for most of this trend, along with 3D interpretation in Bournemouth Bay; and we own a licence for most of the Isle of Wight open acreage 2D seismic, which we also have mapped. The onshore Isle of Wight is of particular interest for geothermal, in the footwall structures south of the Chalk outcrop, in a belt which includes large agricultural interests and an airfield with light engineering businesses.

Wytch Farm Field will no doubt see hot water production developed in due course, from the Trias extended-reach wells under the Bay, extending field operating life as the oil output runs down. It's a primary future play recognised in UK geothermal literature. Another particular block of interest is ML5 at Kimmeridge field: one could anticipate support from Dorset Council, for geothermal renewables initiative with small footprint.



From Eocene through Miocene, North Africa has impacted on the Europe Plate, building the Alpine fold belt and re-shaping UK sedimentary basins. Strong uplift effects are seen in all the UK basins. Dorset through Isle of Wight deformation belt is one result. Its not a two-dimensional deformation: its oblique-slip, ideal for exploring fractures bearing hot water.

This seismic line part-shown from Weymouth Bay through Kimmeridge/Purbeck shows partly or wholly-reversed south-extensional faults along with massive sets of much younger northward-climbing fractures, in red. The sketched reds are inverting surfaces, on which rocks travelled north deforming the Mesozoic basin. The displacement on the red faults is away from the eye, into the plane of this section. Kimmeridge-5 well, in blue, is shown in the next slide, running north-south.



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Gas Council 80-268 is a dip line, trending from Kimmeridge Bay northwards from near-K-5 to Creech-1 area, it is just under 5 km in length, the two wells are about 3.7 km apart, Creech data projected half a km eastwards.

The inversion is multi-stage and resulted in mixed compression superimposed on original extension. Oldest fault to reverse here is 1, and it is partly-reversed Mesozoic extensional. Its footwall collapse duplex records progressive breakdown in Tertiary age reversal, as its too steep to simply reverse, it breaks repeatedly from top downwards, its floor fault is 2a in the Lower Jurassic Lias shales. The roof fault (blue arrow, 2b) could be partly balancing the south-to-north stacking. Fault 3 is another extensional re-used in shortening as it has a low dip.

All this is perfect, for interconnecting fractures with hot water.

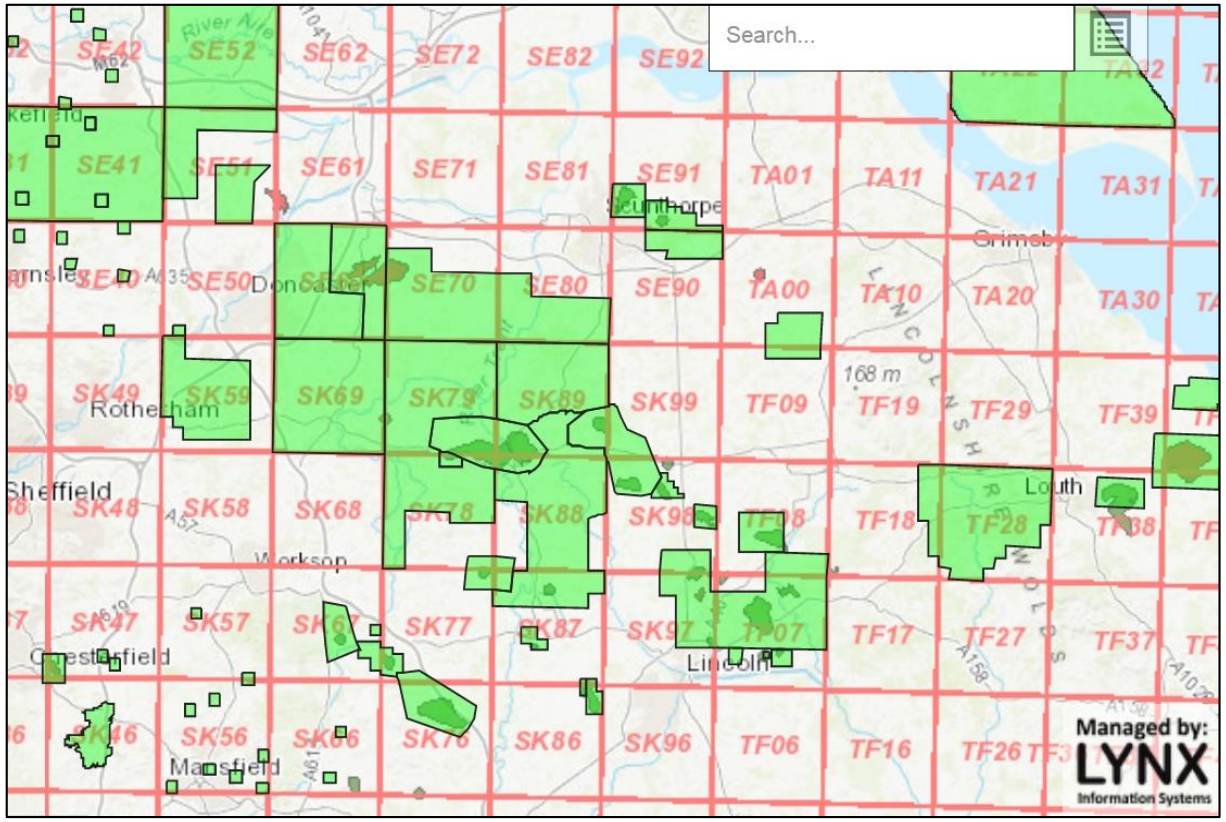
Fractured reservoirs in the Carboniferous of East Midlands: current licences

In this note we don't document targets in the Carboniferous basins: the proving wells study at this stage requires appreciable matrix poroperms as well as fracturing.

This map is shown just to make the point that current licence coverage in East Midlands, which could be immediately drawn into geothermal projects, is significant. Looking beyond the Permo-Trias, fractured Carboniferous plays which we have identified number more than twenty and are chosen with seismic confirmation of probable major faulting. These are high-priority targets <u>when the initial well project validates the design</u>. There are several dozen licensee companies here with blocks which can permit geothermal drilling, now.

Although Carboniferous reservoir rocks have low to very low matrix permeability, the presence of dense faulting promises high secondary permeability which controls an effective rate of circulation of hydrothermal fluids, allowing us to plan open-loop wells with slotted liner interconnection. In the northern England and Scotland basins recent glaciation and melting has loaded then unloaded them and re-opened fractures at target level. Drilling mud overpressure following recent glaciation phases will re-open joints and faults, when pressure is repeatedly varied to enhance natural fracturing and micro-fractures.

Follow-up potential for open-loop projects is appreciable here, and in due course presently open areas may become re-licensed for geothermal, as there is huge energy reserve here.



How can we fast-track geothermal projects, in late 2025?

In these notes HGL has restricted its presentation to one style of geothermal prospectivity. Our aim is to encourage innovative thinking and practical commitment to what is a highly promising field for investment.

The latest, end-2024 IEA report on geothermal energy potential world-wide (www.iea.org) follows previous compilations in acknowledging geothermal resource as vast. It acknowledges developing technologies will drive commercial projects by reducing costs and investment risk. To quote IEA, "With continued technology improvements and reductions in project costs, geothermal could meet up to 15% of global electricity demand growth to 2050. This would mean the cost-effective deployment of as much as 800GW of geothermal power capacity worldwide, producing almost 6000 terawatt-hours per year, equivalent to the current electricity demand today of the United States and India combined".

Well, looking at the latest drilling cost figures from US projects, that IEA comment was on the right lines: but it under-estimates the real possibilities! Applying lessons learned from shale gas well drilling in USA basins, UK costs per well can certainly be contained, with more breakthroughs to come. Drilling faster is the game changer. What's the status of research into increasing ROP, e.g. by high-pulse electric discharge to fracture rock ahead of the bit? Hammering as well as rotary drilling? Better poly-crystalline bits? High pressure water jets? All these are areas to watch; but skilled well designers are the key.

What next? In our view, in November 2025 the fastest way to develop a commercial interest in geothermal energy projects onshore UK is to use oil and gas licenses as the basis for an initial entry. Ventures with oil companies holding onshore blocks which feature deep, fractured Permo-Trias are presently the optimum way for geothermal projects to be validated and completed quickly onshore UK. Current oil licenses provide the framework for deep drilling and recognise ownership of wells approved and completed; and operators have the skills and experience to plan, reach and produce reservoir fluids at 100-125 degrees in large volume.

The opportunity is significant.