BASIN-CENTERED STRATIGRAPHIC RESERVOIRS – POTENTIAL FOR LARGE SCALE GEOTHERMAL POWER GENERATION IN THE U.S.

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Keywords: *Stratigraphic reservoirs, geothermal resources, Great Basin, permeability, heat flow, power potential.*

ABSTRACT

Recent growth in the installed geothermal power capacity of the U.S. has utilized binary plants mostly located on moderate-temperature hydrothermal systems. Many of the more attractive and accessible systems have been developed or are under investigation, and blind hydrothermal systems are difficult to locate. These moderate temperature systems are typically small (< 10 km^2 in area) and power plants are often 10 – 30 MWe in size. If the U.S. is to achieve 5 - 10 GWe growth in geothermal capacity during the next decade as advocated by the Dept. of Energy Geothermal Technologies Office, it requires 100 MWe-scale power developments. This size power plant requires reservoir volumes of ~ 10 km^3 for developments producing at near the installed capacity for at least 30 years. The modest success of EGS pilot projects since 1980, and the small size of moderate-temperature hydrothermal reservoirs in the western U.S. suggest limited potential for power growth in the next decade from these types of reservoirs.

Stratigraphic reservoirs in high heat flow basins of the western U.S. have the potential to sustain 100 MWe-scale power developments and contribute the required growth. These sub-horizontal reservoirs need to have a temperature of at least 175°C for a levelized cost of electricity of US$ 100/MWe-hour, and are likely to be at 3 – 4 km depth in basins where the heat flow is at least 80 mW/m^2. A review of porosity and permeability data from both oil reservoirs and groundwater aquifers suggests the high permeabilities required for geothermal production wells (100 mDarcy) are not uncommon. Modeling with reservoir transmissivities of 3 – 10 Darcy-meters yields power densities in the range 3 – 10 MWe/km^2 of reservoir area. In the eastern Great Basin, large areas of Paleozoic carbonates underlie Tertiary–Quaternary fill in basins and appear to be the most attractive reservoir target.

1. INTRODUCTION

After more than a decade with the installed capacity of geothermal power in the U.S. plateaued at about 3 GWe, federal government stimulus spending since 2009 has helped to increase the installed capacity to 3.4 GW by 2012, and the geothermal industry expects an additional 800 MWe online by 2015 (GEA, 2013; Fig. 1). However, geothermal power is no longer the dominant renewable energy source (excluding hydropower) for power in the U.S. The installed capacity of both wind and solar power now exceed 60 GWe and 7 GWe respectively, with both growing at more than 10%/year. The Geothermal Technologies Office (GTO) of the U.S. Department of Energy has a target to increase the installed geothermal power capacity to more than 10 GWe by 2025 (Hollett et al. 2013). This is envisaged as a mix of generation from blind hydrothermal systems, hot water co-produced with oil and gas production, enhanced geothermal systems (EGS) and known, undeveloped systems. To achieve a tripling of geothermal power in about a decade will require many power plants of at least ~ 100 MWe in size, and power generation at costs of ~ US$100/MWe-hour or less to be competitive in today's electricity markets.

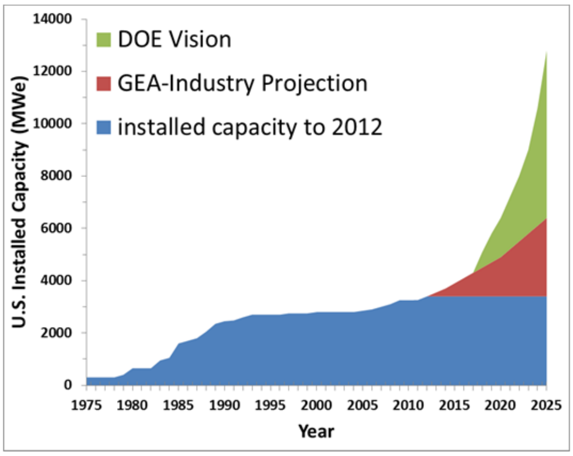

Fig. 1. Installed geothermal power capacity to 2012 with geothermal industry predictions and U.S. DOE national goals to 2025 (modified from Hollett et al. 2013).

The purpose of this paper is to point out that a fourth type of system, hot sedimentary reservoirs with natural high permeability, may offer a more rapid path to geothermal power growth in the U.S. in the coming decade than has previously been appreciated. These stratigraphic reservoirs are slightly deeper than the geothermal industry has considered economic (3 – 4 km depth for temperatures of up to 200°C), but compensating for the additional cost of deeper wells is the large area of prospective, sub-horizontal reservoirs, and the potential for power plants that are hundreds of MWe in size. The thermal regime of the western U.S. is globally unusual because of the very large area of high heat flow (more than 500 x 500 km^2 at 80 – 100 mW/m^2) as a result of Neogene extension. There is now a basin and range topography where Paleozoic shelf sediments are situated beneath 1 – 3 km of unconsolidated basin fill in the basins, and regional temperatures at 3 – 4 km depth are 150 – 200°C due to the conductive thermal gradient. Some of the buried shelf sediments are known to have characteristically high permeability, especially some carbonate formations beneath the eastern half of the Great Basin (Allis et al. 2011, 2012, 2013). The technologies for finding and developing these reservoirs (gravity, heat flow, seismic reflection surveying, conventional drilling and stimulation) already exist and are mature. There are few environmental issues that could impede development, as long as air-cooled binary power plants are used and there is no water consumption between production and injection wellheads. Based on the areas of individual basins (each ~ 1000 km^2), once a reservoir target is confirmed, the scale of a particular development may be several hundred MWe because of the sub-horizontal reservoir geometry.

2. GEOTHERMAL TECHNOLOGY CHALLENGES

All three forms of new geothermal power generation identified by the GTO have engineering and economic challenges that require government support if technological breakthroughs are to be achieved. Most of the accessible hydrothermal systems in the U.S. have already been developed, and it is becoming increasingly difficult to locate blind systems. Faulds et al. (2012) suggest geological indicators such as fault style and strain rate as exploration tools for finding blind systems in the Great Basin, and Garg et al. (2010) review possible geophysical signatures. However, Blackwell et al. (2012) suggest the upflow zones of hydrothermal systems in the Great Basin are relatively small in cross-sectional area, with the implication that their sustainable power potential may not be large.

The greatest potential for power generation from hot water coproduced with oil and gas production is in the Gulf Coast region of Texas, where wells deeper than 6 km have temperatures of more than 150°C. Although numerous wells are drilled to more than 6 km depth, gathering sufficient coproduced hot water for a 100 MWe geothermal power facility (> 2000 L/s depending on temperature and conversion efficiency) is a major technological and economic hurdle. Augustine and Falkenstern (2012) have investigated the co-produced water power potential in the U.S. and found the required data (production temperature and flow rate) are often poor. They concluded that most co-produced water is not hot enough (60% of wells with temperature of less than 80°C), and the potential may only be a few hundred MWe assuming the most prospective producers are co-located and gathering the separated water at a power plant is feasible.

EGS projects, where the reservoir is created in a hot, initially low-permeability host rock by hydrofracturing, have been attempted in several countries since the 1970s with limited success. The potential for EGS in the U.S. is vast (~ 100 GWe; Tester et al., 2006; USGS, 2008) but the challenge has been creating a fracture network on a large enough scale to sustain commercial flow rates and temperature for decades. Five demonstration projects are presently being funded by the GTO (at The Geysers, Desert Peak, Brady's Hot Springs, Raft River, and Newberry Volcano), with promising results in their initial phases of stimulation (Ziagos et al., 2013). At Desert Peak, the stimulation has resulted in a 1.7 MWe improvement in power plant output (Chabora and Zemac, 2013). Four of these projects are expansions of developed geothermal systems; Newberry Volcano is undeveloped.

In their modeling of an EGS reservoir, Sanyal and Butler (2005) found the recoverable fraction of heat was typically about 40% for reservoirs with characteristic fracture permeabilities of 10 – 100 mD, and fractures at 3 – 30 m spacing. The required reservoir volume for a 30-year economic life was 26 MWe/km^3, or about 4 km^3 for a 100 MWe power plant. However, Tester et al., (2006) have questioned whether the 40% heat recovery factor is achievable given the challenges of creating large, uniform fracture networks, and experience in projects where flow short-circuits develop in the reservoir. More recently, Grant and Garg, (2012) and Garg and Combs (2010) pointed out that naturally fractured reservoirs appear to have heat recovery factors of 5 – 15%, and for some EGS projects the heat recovery decreases to a few percent. Assuming a more modest 10% recovery factor for an EGS project, a 100 MWe power plant needs a reservoir of about 16 km^3. Creating a 10 – 100 mD uniformly fractured reservoir of this volume still appears to be several decades away (Pritchett, 2012).

The oil industry has had spectacular success over the last decade in hydrofracturing low-permeability rocks (mostly organic-rich shales, which are petroleum source rocks) so that they produce economic flows of oil and gas. This raises the question of whether new technologies including wells with long horizontal legs, and multiple stimulations per well, result in flow rates that could be of interest if applied to a low permeability geothermal setting. In three unconventional oil plays (Bakken, North Dakota; Woodford, Oklahoma; and Uteland Butte-Uinta, Utah), horizontal legs range up to 1 – 3 km, and hydrofracturing of up to 30 – 40 stimulation stages per leg is not uncommon. Initial production rates are reported to be in the range 500 – 2000 barrels/day (that is, about 1 – 4 L/s; Redden, 2013a, 2013b, Vanden Berg et al., 2013). However, these flow rates at the Bakken play decrease rapidly to about 15% of the initial flow rate after three years (Hicks, 2013), and subsequently decline much more slowly to a rate of about one tenth the original production rate for several decades. Well data on North Dakota's DMR website show average production rates for more than 3000 wells drilled in the Bakken tight-oil play since 2010 are 140 barrels/day (0.3 L/s). In 2012, the average Bakken well had a 2 – 3 km horizontal leg at almost 3 km depth and cost $9 million to drill and complete (Hicks, 2013). The horizontal well density at Bakken is one leg per 2 square miles (5 km^2).

Unfortunately, the flow rates stimulated in tight oil plays are usually two orders of magnitude below those required for utility-scale geothermal power generation (~ 50 – 100 L/s; 27,000 – 54,000 barrels/day), and they demonstrate the difference in energy value at the wellhead between oil and hot water. Although this is an apparently disappointing result, there is an important caveat: with tight-oil stimulation the induced fractures are designed to stay within the low permeability source rocks (usually less than 100 m radius depending on the source rock thickness). In the Barnett Shale play (Texas), engineers avoid fractures growing downward from the Barnett Shale into the underlying Ellenberger Limestone, after which the well may produce significant volumes of water (Maxwell et al. 2010). The restricted fracture length is achieved through real-time microseismic monitoring and limiting injection flow rates. In a vertically stratified geothermal reservoir, such a restriction does not apply, and in fact hydrofracturing that cross-cuts low permeable units and links more permeable units or fracture zones in a reservoir is highly desirable.

3. SEDIMENTARY GEOTHERMAL RESERVOIRS

Some deep sedimentary formations in the U.S. are known to have the requisite permeability for a geothermal reservoir, and if such formations exist in a high heat flow basin, there may be significant power potential using existing technologies (Allis et al. 2013). When near-market economic constraints of a levelized cost of power of US$100/MWe-hour over a 30-year reservoir life are applied, production and injection wells supporting a 100 MWe power plant with a moderate temperature reservoir (less than 200°C) need to have flow rates of ~ 50 – 100 L/s so that the well costs do not become prohibitive. For the same reason, wells need to be less than about 4 km in maximum depth. An upper temperature threshold of about 200°C exists because of present pump technology, and these pumps also have an upper flow rate of about 130 L/s. If production wells have exceptional permeability and also are significantly hotter than 200°C, they can self-discharge. However, such wells are likely to be intersecting a hydrothermal upflow (at < 4 km depth), rather than a conductive thermal regime where such temperatures are too deep for heat flows of 80 – 100 mW/m^2. The two most critical questions are: Do high heat flow basins exist with potential stratigraphic reservoirs within the temperature-depth constraints mentioned above; and do the prospective sedimentary reservoirs have the required permeability?

3.2 Thermal regime

Figs. 2 & 3 show that basins with heat flows of more than about 80 mW/m^2, and at least 2 km of relatively low conductivity sediments (such as unconsolidated fill or mudstone-shale) have temperatures in the range of 150 - 200°C at 3 – 4 km depth (zone labeled "the Prize"). Large areas of the western U.S. have a heat flow of more than 80 mW/m^2, including the Great Basin, Snake River Plain – Yellowstone, and the Southern Rocky Mountains – Denver Basin (Blackwell et al. 2011), representing one of the largest regions with high heat flow on the Earth's continents. "The Prize" on Fig. 2 is at slightly greater depth than most moderate temperature hydrothermal reservoirs that have been drilled in the Great Basin. Beneath the eastern half of the Great Basin is the Lower Paleozoic Carbonate System renowned for its aquifer properties (Heilweil et al. 2011). In several basins within the Great Basin, where these carbonate units occur at more than 2 km depth, preliminary screening of abandoned oil exploration wells shows temperatures of more than 175°C at 3 – 4 km depth (Allis et al. 2013). Many basins are attractive for more detailed definition of the geothermal potential. The northern Great Basin may be the most prospective because of the internal drainage and reduced hydrological disturbance to the conductive heat flow. Lower heat flow in the southern Great Basin is attributed to interbasin groundwater flow and deep flushing towards low elevation topography south of Las Vegas, perhaps through the underlying Paleozoic carbonate units (Lachenbruch and Sass, 1977; Masbruch et al. 2012).

3.2 Permeability

The greatest challenge to proving that hot basins have viable stratigraphic reservoirs suitable for utility-scale power generation is that production wells penetrating "The Prize" zone need to find adequate permeability. Numerical modeling by Deo et al. (2013) and by Sanyal and Butler (2005) in the case of uniformly fractured reservoirs both point to reservoirs with permeabilities of about 100 mD in order to achieve the adequate flow rates without excessive pressure decline. In contrast to hydrothermal reservoirs where reservoir production is usually controlled by widely-spaced fractures, stratigraphic permeability depends on the particular formation and its thickness. The transmissivity, or permeability-thickness product, is probably more meaningful for well productivity, and values of about 10 Darcy meters (100 mD over a 100 m thickness) are what is required for flow rates of 50 – 100 L/s (Deo et al. 2013). Such flow rates are found in oil and gas reservoirs, although they are at the upper end of the range. A good U.S. oil well in a traditional, stratigraphic reservoir flows at about 5000 barrels/day, or 10 L/s. A good Middle Eastern oil well can flow at 10 times this rate. The Macondo well that flowed uncontrollably into the Gulf of Mexico in 2010 flowed at 50,000 – 70,000 barrels oil per day (90 –130 L/s; McNutt, et al. 2012).

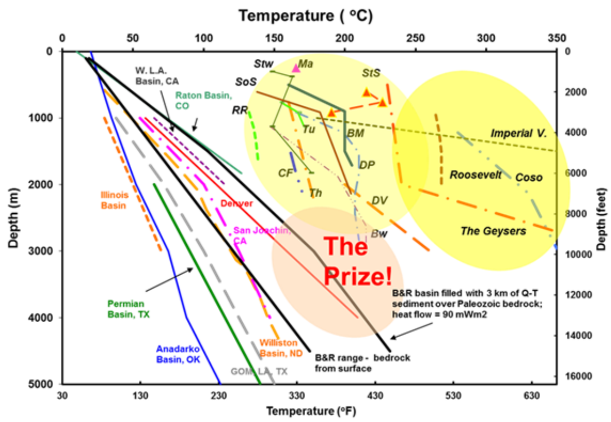

Fig. 2. Hydrothermal systems in the western U.S. (yellow – high temperature systems; light yellow – moderate temperature systems). "The Prize" is the zone of potential stratigraphic reservoirs beneath high-heat flow basins that should be a target for future geothermal development (Allis et al. 2012). Also shown are profiles from several large sedimentary basins. Most U.S. geothermal developments are at temperatures of more than 150°C, and less than about 3 km depth. Two geotherms representing high heat flow (90 mW/m2) beneath deep basins and beneath ranges in the Great Basin are plotted. Note that temperatures at 3 – 5 km depth are about 50°C hotter beneath a basin than at the same depth beneath an adjacent range with outcropping bedrock. Key: L.A., Los Angeles Basin; GOM, Gulf of Mexico onshore (Louisiana) and offshore (TX). Geothermal systems: Stw, Stillwater, NV; Ma, Mammoth, CA; StS, Steamboat Springs, NV; SoS, Soda Springs, NV; Tu, Tuscarora, NV; BM, Blue Mountain, NV; DP, Desert Peak, NV; Ro, Roosevelt, UT; CF, Cove Fort, UT; Th, Thermo, UT; Tu, Tuscarora; DV, Dixie Valley, NV; Bw, Beowawe, NV; RR, Raft River, ID. The location of these systems is shown in Fig. 3.

Ehrenberg and Nadeau (2005) have compiled porosity and permeability data for reservoirs from around the globe, subdividing the data into siliclastic and carbonate reservoirs. Their results provide insight on the likelihood of finding 100 m permeability at 3 – 4 km depth. The authors plot porosity against depth, and porosity against permeability, and they note that plotting porosity against reservoir temperature rather than depth would have been more meaningful, but that the temperature information was not readily available. However, some inferences about permeability with depth can be drawn from their two graphs. Fig. 4 (upper) shows statistical trends from 8300 porosity-depth pairs, with P90 indicating 90% of the porosity values within the depth bin (500 m) are above that line. The lower graph shows the results of 29,000 porosity-permeability data pairs. The porosity-depth trends show siliclastic reservoirs have as much as 5% systematically higher porosity at any depth compared to carbonates. At 3.5 km depth, the median porosity of carbonate is 8% compared to 15% for siliclastic reservoirs. However, Ehrenberg and Nadeau (2005) also show a porosity trend for a quartzose sandstone from offshore Norway where there is moderate temperature gradient (35°C/km). Although the porosity is unusually high at 1 – 2 km depth (30 – 35%, inferred temperature about 60°C), at 4 km depth and an inferred temperature of about 145°C, the porosity is only 10% and is approaching the P90 line. This highlights a caution that at the desired temperatures of 150 – 200 °C, diagenesis may result in significantly diminished quality of siliciclastic reservoirs. Carbonates typically become less soluble with increasing temperature, so if relatively pure, these reservoirs may not be as sensitive to increasing temperature as siliciclastic reservoirs.

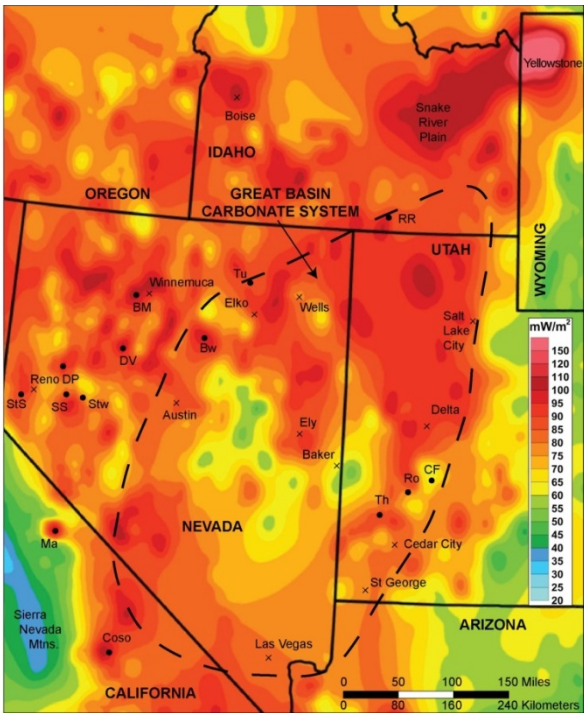

Fig. 3. Heat flow map centered on the Great Basin of the western U.S. (Blackwell et al., 2011), overlain by developed geothermal systems (black dots, with labels from caption in Fig. 2). The eastern Great Basin contains up to 5 km thickness of Paleozoic carbonates (labeled as "Great Basin Carbonate System") known to have high permeability (Heilweil and Brooks, 2011; Masbruch et al. 2012). These carbonates locally occur beneath up to 3 km of basin fill.

The distribution of above-average porosity (P50 up to P10) between 3 and 4 km depth is superimposed on the porosity-permeability trends in Fig. 4 assuming the data also corresponds to same the P50 – P10 distribution. This is reasonable because porosity and log permeability are correlated. In carbonates, the permeability range is about 30 – 200 mD, and in siliclastic reservoirs it is about 50 – 500 mD. This is consistent with the permeability required for geothermal production wells.

As a check on whether these results represent reservoirs in the western U.S., Kirby (2012) reviewed oil exploration and groundwater databases for the Great Basin and adjacent basins in the Rocky Mountains to characterize permeability as a function of depth and dominant lithology (Fig. 5). Permeability values had been determined by drill stem tests and aquifer pump tests. All lithologies show a significant decline in permeability between the surface and about 1 km depth. However, at greater depth the trend for both siliciclastics and carbonates is remarkably constant. Between 3 – 5 km depth, the average permeability for carbonates is 75 mD and that for siliciclastic rocks is 30 mD. In contrast, the permeability of basin fill and igneous lithologies (volcanic and intrusive rocks) decreases rapidly with increasing depth to about 1 mD at 2.5 km, the maximum depth for which there is data. The data for carbonates are similar to those for the global dataset, but the siliciclastics reservoirs are five to ten times lower. The majority of the data at 3 – 5 km depth comes from reservoirs in the Rocky Mountain province, so perhaps the thermal history here has reduced the quality of siliciclastic reservoirs.

4. DISCUSSION

Hot stratigraphic reservoirs are attractive targets because of their natural permeability. In tectonically active areas such as the Great Basin, joints, fractures and faults may also enhance the permeability at depth. Although geothermal wells require high flow rates and good reservoir permeability by petroleum standards, the 100 mD permeability target is not uncommon for sedimentary reservoirs. Similarly, the very large area of high heat flow in the Western U.S. (more than 80 mW/m^2) and thick sedimentary sections within this area of 3 to more than 6 km provides opportunities for large-scale power developments if reservoir depths of 3 – 4 km are considered. At these depths, temperatures of 150 - 200°C are present, with the highest temperatures occurring beneath the deepest portions of basins where the thermal resistance (thickness/thermal conductivity) of the overlying sediments is a maximum. The broad, central parts of basins in the Great Basin have not, in general, been a focus for geothermal exploration, which has targeted finding hydrothermal upflows on range-bounding faults.

An example of a sedimentary section in a high heat flow basin of the Great Basin is the northern Steptoe Valley, about 50 km north of Ely in eastern Nevada (Figs. 6, 7). Deep exploration wells here confirm temperatures of 175 – 200°C at 3 – 4 km depth. The dominant lithologies at these depths are limestone and dolostone, and major loss zones and fractures were encountered in these formations. The wells are 20 km apart, so the prospective reservoir area is at least 100 km^2 (Allis et al. 2012). Although seismic reflection surveying has been challenging for locating hydrothermal systems along range fronts in the Great Basin, Schelling et al. (2013) demonstrate that in the central regions of basins of the Great Basin, the technique is ideal for delineating stratigraphic reservoirs.

In contrast to hydrothermal systems where the permeability is largely on sub-vertical faults and fractures, stratigraphic reservoirs are sub-horizontal. Basins in the Great Basin are commonly 10 – 30 km wide and are typically more than 100 km long. The areas of prospective stratigraphic reservoirs may therefore be at least two orders of magnitude large than most hydrothermal systems in the Great Basin. The reservoir volume required for a 100 MWe power plant for more than 30 years depends on the effectiveness of the heat sweep between injection and production wells, but is at least 10 km^3. Assuming the reservoir comprises a total of 100 m of stratigraphic units with 100 mD permeability and they are distributed within a 300 m depth range, the modeling of Deo et al. (2013) shows that the borefield area supporting a 100 MWe plant needs to cover about 30 km^2. This modeling assumes producers and injectors are located in a repeating 5-spot pattern with wells 500 m apart; the wells are pumped at 70 L/s, and the initial reservoir temperature is 200°C. A range of reservoir permeabilities with an overall transmissivity between 3 and 10 Darcy-meters confirms power densities varying between 10 MWe/km^2 early on in the development, declining to about 3 MWe/km^2 subsequently. This means capital investment can be staged, with infill or expansion wells drilled later in the development cycle.

Although these stratigraphic reservoirs are at 3 – 4 km depth and slightly deeper than the geothermal industry is used to, preliminary economic modeling indicates levelized costs of electricity of about US$100/MW-hour depending on factors such as the rate of reservoir temperature decline, and well productivity (Allis et al. 2013). Well costs were assumed to vary between $5 – 8 million for this depth range of reservoir (vertical wells). When considering a utility-scale development there will be economies of scale, both in grouping multiple wells on the same drilling pad, and also from similar, step-out drilling across a basin, where each well has the same subsurface geological and hydrological characteristics. Such drilling is commonplace in oil and gas developments with enhanced recovery in waterfloods, and more recently with tight oil and gas production wellfields. The economic modeling shows that the most attractive prospects are in reservoirs with temperatures of at least 175°C, and wells are less than 4 km depth.

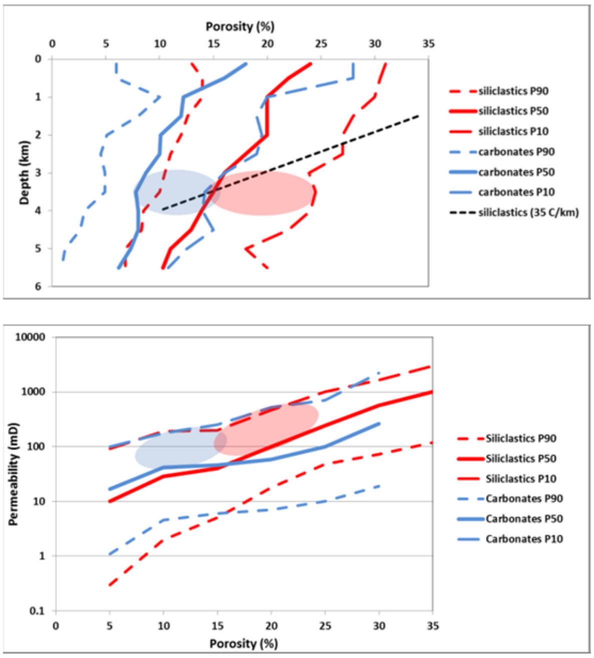

Fig. 4. Global trends in reservoir porosity with depth (upper graph) and porosity vs. permeability (lower graph), modified from Ehrenberg and Nadeau, (2005). Labels such as P90 mean that 90% of the data lie above the trendline, and P50 is the median trend. Colored ellipses highlight the approximate distribution of above average porosity within the 3 – 4 depth range, and the equivalent distributions in poro-perm space. The black dashed line in the upper graph is the porosity trend in a moderate heat flow basin (35°C/km) from offshore Norway.

The greatest challenge for stratigraphic reservoirs seems to be proving that laterally extensive, high permeability naturally exists at 3 – 4 km depth where formation temperatures are 175 – 200°C. Once one or two geothermal exploration wells verify that these reservoirs exist beneath some basins, and 100 MWe-scale power plants are feasible, significant investment from the geothermal industry will follow. In fact, some hot oil and gas production wells already demonstrate that high-temperature and high-permeability exist in appropriate sedimentary lithologies. One obvious example is the normally pressured, Madison carbonate reservoir at 6 – 7 km depth in the Wind River basin of northern Wyoming where the temperature is 215°C and there is good permeability (Dyman et al. 1997; Williams, 2000). If several GWe of new geothermal power developments are to be achieved in the next decade in the U.S., stratigraphic reservoirs in hot basin settings need to be pursued aggressively, along with continued technology development for EGS and blind hydrothermal systems.

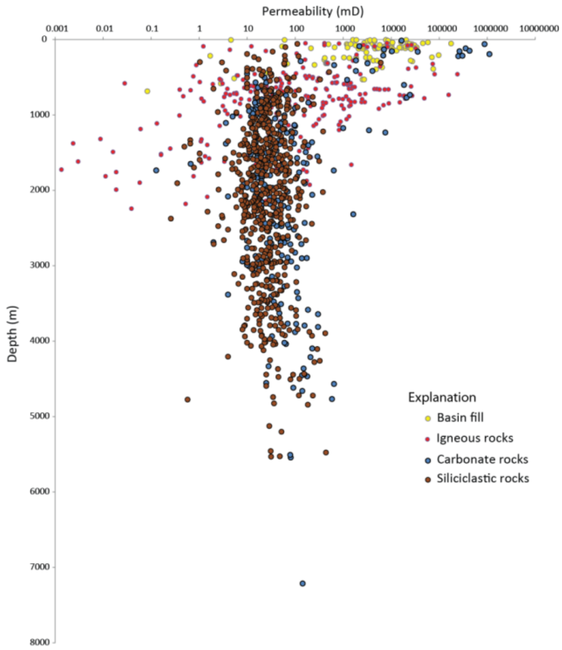

Fig. 5. Compilation of permeability measurements in oil exploration and groundwater databases from the Great Basin and Rocky Mountains regions (Kirby, 2012).

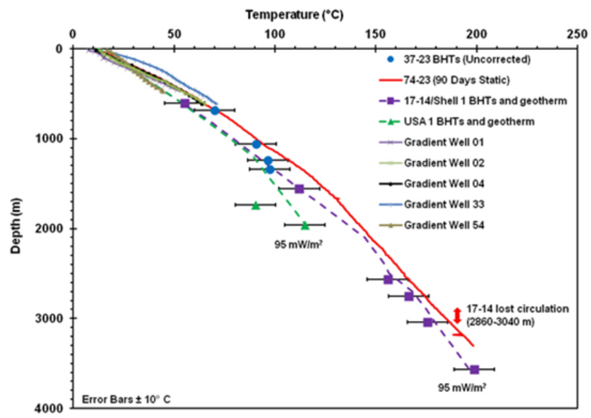

Fig. 6. Temperature data from oil and geothermal exploration wells in North Steptoe Valley, 50 km north of Ely in eastern Nevada (located on Fig. 3). Geothermal wells 37-23, 74-23, and the Gradient wells are about 20 km from the oil wells 17-14 and Shell 1. The area with temperatures of 175 - 200°C appears to cover at least 100 km^2 (Allis et al., 2012).

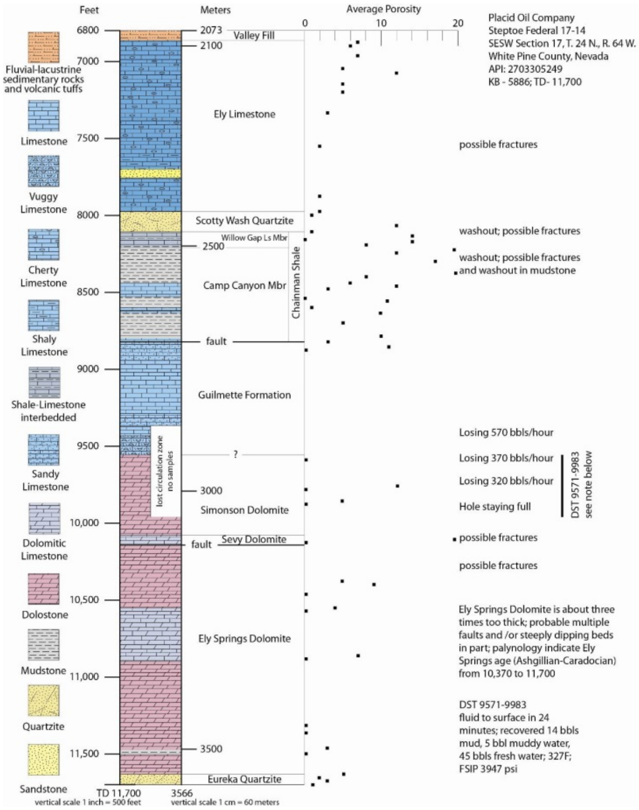

Fig. 7. Detailed stratigraphy of bedrock section of oil exploration well Placid Steptoe Federal 17-14 in northern Steptoe Valley, Nevada. The dominant lithology between the base of Valley Fill at 2100 m depth and Eureka Quartzite at 3550 m depth is lower Paleozoic carbonate (Allis et al. 2012).

ACKNOWLEDGEMENTS

This paper is a follow-up from research carried out during Phase I of a Project titled: "Novel Geothermal Development of Sedimentary Basins in the United States," Moore, J.N. and Allis, R.G. (co-Principal Investigators). The project was partially funded by the Geothermal Technologies Program of the U.S. Dept. of Energy (Award DE-EE0005128). Mark Gwynn and Doug Sprinkel (UGS) compiled the material for Figs. 6 & 7; Jay Hill, (UGS) drafted some of the figures. We thank Joseph Moore, Doug Hollett, Rob Ressetar, and Kimm Harty for helpful comments on earlier drafts.

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