Acceleration of Deep Subsurface Fluid Fluxes in the Anthropocene

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Abstract

The Anthropocene has been framed around humanity's impact on atmospheric, biologic, and near-surface processes, such as land use and vegetation change, greenhouse gas emissions, and the above-ground hydrologic cycle. Groundwater extraction has lowered water tables in many key aquifers but comparatively little attention has been given to the impacts in the deeper subsurface. Here, we show that fluid fluxes from the extraction and injection of fluids associated with oil and gas production and inflow of water into mines likely exceed background flow rates in deep (>500 m) groundwater systems at a global scale. Projected carbon capture and sequestration (CCS), geothermal energy production, and lithium extraction to facilitate the energy transition will require fluid production rates exceeding current oil and co-produced water extraction. Natural analogs and geochemical modeling indicate that

subsurface fluid manipulation in the Anthropocene will likely appear in the rock record. The magnitude and importance of these changes are unclear, due to a lack of understanding of how deep subsurface hydrologic and geochemical cycles and associated microbial life interact with the rest of the Earth system.

Key Points

- Current anthropogenic fluid fluxes in the deep subsurface likely exceed background fluxes.
- Anthropogenic fluid fluxes in the deep subsurface are expected to accelerate with the energy transition.
- Injection and production of fluids from the deep subsurface is expected to leave a mark on the geologic record.

Plain Language Summary

The Anthropocene is often framed in terms of changes in climate, ecosystems and land use. These have been accompanied by changes in the Earth's water cycle, including depleted groundwater storage due to pumping in many regions. The scale of anthropogenic change in the subsurface at depths beyond typical water wells has received less attention. Fluid flow rates associated with oil and gas production likely exceed natural groundwater flow rates at depths greater than 500 m. Anthropogenic impacts to this deeper zone of the Earth's subsurface are expected to increase dramatically as we look to store carbon, mine lithium from deep brines and produce geothermal energy as part of the ongoing energy transition.

Introduction

The Anthropocene is often thought of in terms of land use change, greenhouse gas emissions and climate change, biodiversity and the appearance of distinctive physical and chemical features in the stratigraphic record (Crutzen, 2002; Lewis & Maslin, 2015; McCarthy et al., 2023; Seddon et al., 2016). The atmosphere has changed dramatically since the Industrial Revolution with rising carbon dioxide and methane concentrations (Crutzen, 2002). Land use change has resulted in substantial increases in erosion (Borrelli et al., 2017). Excavations and boreholes are widespread (Zalasiewicz et al., 2014), particularly in urban environments (Melo Zurita et al., 2018). Combined with aggregate extraction for building materials, humans are the largest geomorphologic agent on Earth (Syvitski et al., 2022). The hydrologic cycle has also been profoundly altered at a global scale, with changes in soil moisture, surface water, the cryosphere and groundwater at scales impacting the Earth system (Gleeson et al., 2020). How the Anthropocene is manifested in the deeper subsurface, below typical depths of current groundwater extraction (>~500 m), has received less attention(Melo Zurita et al., 2018). Pores and fractures at these depths contain the largest volume of water aside from the ocean (Ferguson et al., 2021) and may contain ~15% of the Earth’s biomass (Bar-On et al., 2018). Groundwater residence times exceeding one million years have been found in a variety of geological settings (Ferguson et al., 2023; Warr et al., 2018), indicating that these deep subsurface ecosystems have been isolated for prolonged periods of geologic time in this “hidden” part of the Earth system that has minimal interaction with the rest of the hydrologic cycle (Warr et al., 2018). Continental to global scale studies tend to treat the subsurface as a black box that is capable of storing or producing fluids without considering how fluxes and microbial communities might change within the subsurface.

Anthropogenic impacts in the deeper subsurface are and will likely continue to be dominated by the production and injection of fluids; extraction of groundwater (Konikow, 2011; Rodell et al., 2018) and oil and gas (BP, 2022; C. Clark & Veil, 2009; McIntosh & Ferguson, 2019) already account for a substantial fraction of deep subsurface fluid fluxes. Subsurface fluid extraction and injection will accelerate with rapidly growing production of lithium (Kumar et al., 2019), helium (Cao et al., 2022), geothermal energy (Nardini, 2022), and storage and production of hydrogen (Miocic et al., 2023) and compressed air (Olabi et al., 2021), as well as, and likely most important, carbon capture and sequestration (CCS) (Benson & Cole, 2008; Krevor et al., 2023; Zoback & Smit, 2023) (Figure 1). Here, we evaluate how fluid fluxes in the Earth's deep subsurface have been affected to date, along with how they are expected to change over the coming century and how this might affect geochemical cycles and microbial communities.

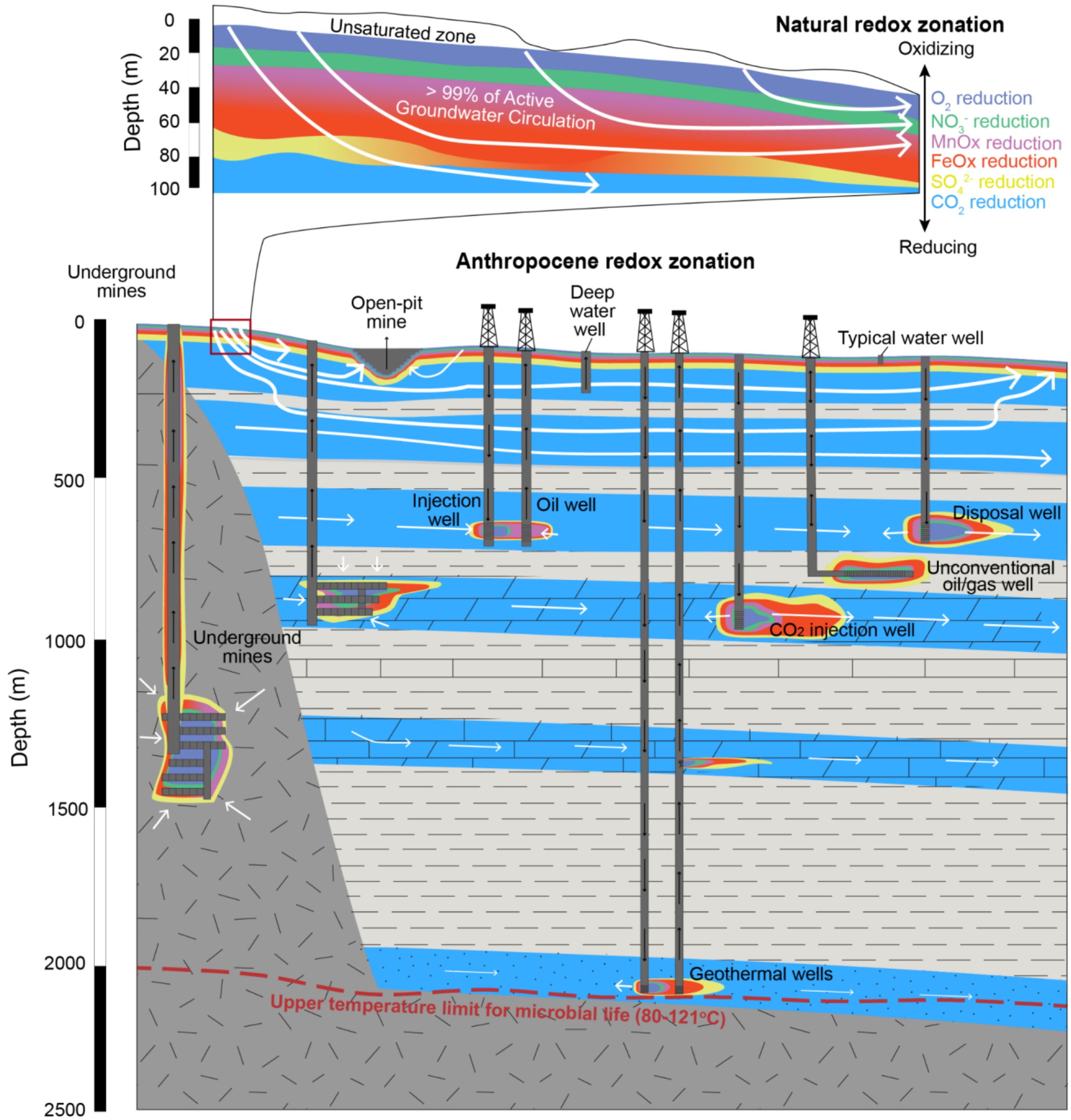

Figure 1: Approximate depths of subsurface activities. Median (31 m) and 95th (130 m) percentile of water wells (Jasechko & Perrone, 2021); minimum depth of CCS in sedimentary basins (800 m) (Benson & Cole, 2008); shallow limit of oil and gas development (including injection and disposal; 600 m) (Lemay, 2008); geothermal (>2,000 m) (Nardini, 2022). The upper temperature limit for life (80-121 °C) (Bar-On et al., 2018; Magnabosco et al., 2018)

approximately corresponds to the lowest temperatures required for geothermal power generation (Nardini, 2022; Tester et al., 2021). Circulation of meteoric water occurs up to depths of a few km (McIntosh & Ferguson, 2021) but fluxes are small below 500 m (Ferguson et al., 2023).

Current Uses of the Subsurface

Groundwater systems have been profoundly affected during the Anthropocene. Approximately 1,000 km^3/yr of groundwater is extracted each year (Wada et al., 2010). While this volume is only ~5 to 17% of global groundwater recharge, where fluxes of 6,000 to 20,000 km^3/yr have been estimated (Döll & Fiedler, 2007; Gleeson et al., 2016; Wada et al., 2010), it has resulted in widespread and substantial losses of groundwater storage, which can now be tracked at monthly scales with remote sensing such as the GRACE satellite project (Rodell et al., 2018). Approximately 3,500 km^3 of groundwater depletion occurred globally between 1900 and 2008 (Konikow, 2011). The extracted groundwater in excess of depletion has largely been balanced by loss of streamflow (Konikow & Leake, 2014). Most extracted groundwater is from wells less than ~35 m deep (Jasechko & Perrone, 2021). Pumping appears to be causing an acceleration of the shallow subsurface hydrologic cycle through increases in hydraulic gradients, as modern water (i.e. containing ^3H from nuclear weapons testing (Gleeson et al., 2016)) is reaching greater depths in areas where large volumes of groundwater have been extracted (Thaw et al., 2022). The corollary of this is that groundwaters that were recharged several millennia ago or longer (GebreEgziabher et al., 2022) are being reconnected with the rest of the hydrologic cycle.

The deeper subsurface (defined here as >500 m) has been more profoundly affected than shallower realms when background conditions are compared to anthropogenic activities. Fluid volumes deeper than 500 m likely exceed 30 million km^3 (Ferguson et al., 2021) but these fluids are weakly connected to the rest of the hydrologic cycle under natural conditions, with estimated fluxes of <13 km^3/yr (Ferguson et al., 2023) (Figure 2). Between 1970 and 2020, approximately 200 km^3 of oil was produced globally (IEA, 2021b). For every 1 m^3 of oil extracted from the subsurface, approximately 3-5 m^3 of water is co-produced (C. Clark & Veil, 2009), resulting in a total fluid volume of 1,000 km^3. The approximately 20 km^3/yr of fluid produced by the oil industry during that 50 year time period likely exceeds any background fluid fluxes at depths between 500 m and a few km in sedimentary basins. Overall fluid budgets in these environments are often near zero because the co-produced water and additional water for reservoir pressure maintenance (i.e. waterflooding) or hydraulic fracturing is injected into the subsurface. However, at subregional scales the production and injection of fluids often results in large changes in hydraulic gradients (Jellicoe et al., 2022).

Environmental concerns surrounding fluids in the deep subsurface have focused on upward leakage into the rest of the hydrologic cycle and the atmosphere (Dusseault & Jackson, 2014; Kang et al., 2014; Lacombe et al., 1995; Perra et al., 2022). However, impacts to the deep subsurface itself will also occur because the chemical and microbial composition of injected fluids differ from *in situ* fluids. Water injected for hydraulic fracturing and secondary recovery (waterflooding) is often seawater, surface water, or shallow groundwater (Bayona, 1993; Kondash & Vengosh, 2015; Scanlon et al., 2019) with various additives (e.g. biocides, corrosion inhibitors) (Elsner & Hoelzer, 2016). Produced and flowback water are often injected into other strata with different original fluid chemistries and this reinjection strategy has become increasingly common in unconventional oil and gas developments. For example, flowback and produced water from the Bakken Formation are routinely injected into the shallower Dakota/Mannville Group in the Williston Basin (Jellicoe et al., 2022; Scanlon et al., 2016) and produced water from the Mississippi Lime, a play relying on dewatering to drive gas exsolution, is injected into the deeper Arbuckle Group in Oklahoma and Kansas (Murray, 2013). However, even where produced water is injected back into its same source strata, the oxidation-reduction (redox) states and microbial communities within these fluids are profoundly altered from their initial conditions. There have been no comprehensive studies examining how these changes affect solute transport, fluid chemistry and microbial activity at regional scales.

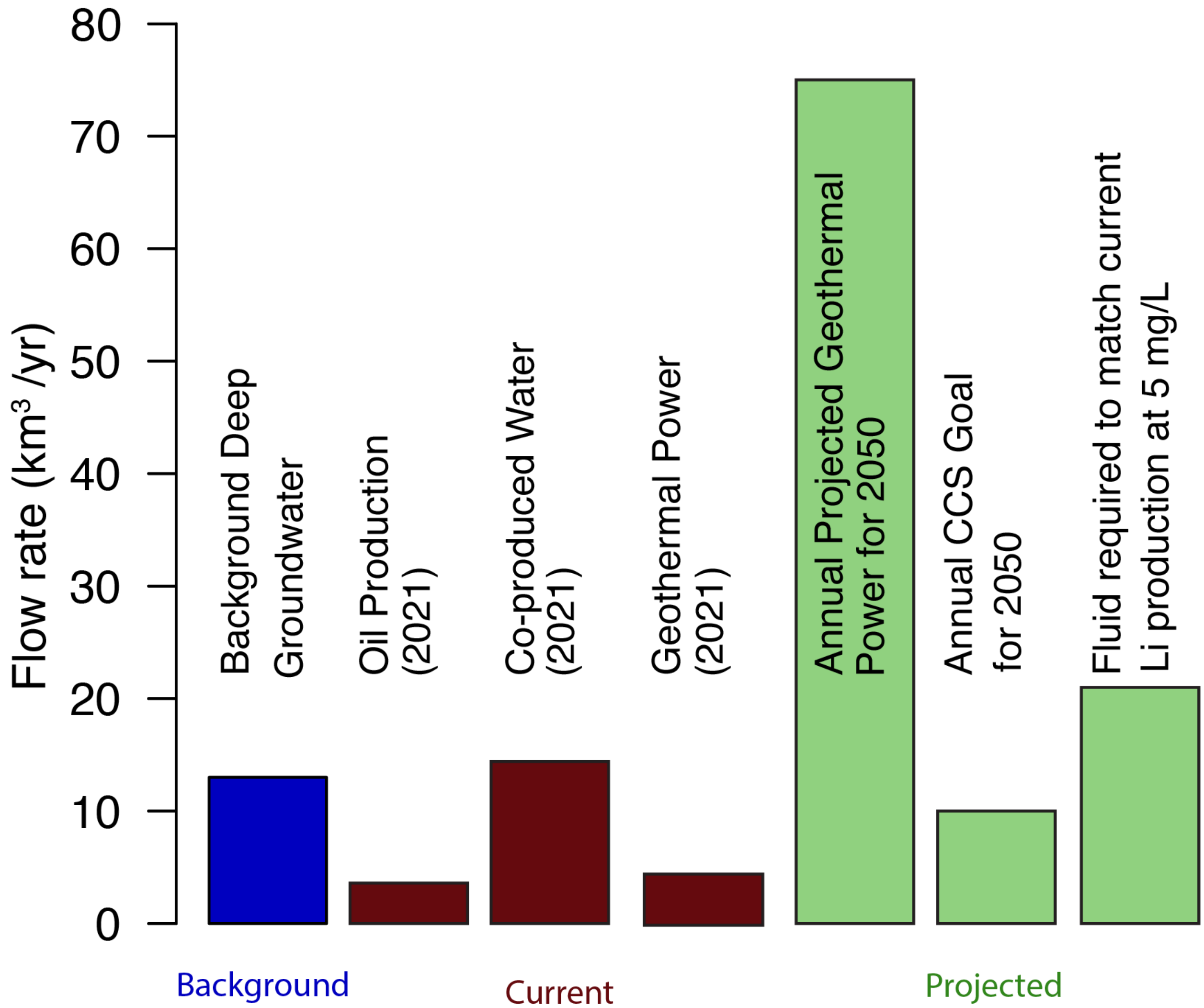

Figure 2: Current oil and gas production involves similar fluid fluxes to natural deep (>500 m) groundwater flow (Ferguson et al., 2023), while current geothermal projects are associated with smaller fluxes (C. E. Clark et al., 2010; IEA, 2021a). Projected fluxes for future CCS (Zoback & Smit, 2023) and geothermal power production (van der Zwaan & Dalla Longa, 2019) are similar to current fluxes from oil and gas production (IEA, 2021b). Scaling up Li extraction (Marza et al., 2023) from sedimentary basins to current global production from all sources would also require a similar amount of fluid.

Fluid injection can have notable effects on the subsurface biosphere, by introducing new microorganisms, fluids with different chemistries and redox conditions, and/or amendments that alter *in situ* microbial communities that have coevolved with fluid and host rock properties over long time periods, in some cases 10s of millions of years or more (Castro et al., 1998; Ferguson et al., 2018). Documentation of these anthropogenic changes to the deep biosphere has rarely been done along with tracking of produced and injected fluid volumes. One well known example is that of reservoir souring, resulting from the introduction of SO_4 via fluid injection, which can stimulate sulfate reducing microbial populations, producing H_2S and reducing fuel grade (Cord-Ruwisch et al., 1987). The common mechanisms of ameliorating this "souring," such as NO_3 injection, represent intentional modulation of the subsurface biosphere at industrial scales. Another is the introduction of *Halanaerobium* in deep hydraulically fractured shale gas reservoirs, which were previously sterile or near sterile(Booker et al., 2019). In some cases, oil and gas companies have intentionally stimulated existing microbial populations to degrade hydrocarbons and produce methane by injecting amendments, such as yeast or algal extracts and nutrients (Barnhart et al., 2022; Ritter et al., 2015). Similarly, CO_2 injection for enhanced oil recovery or storage can enhance microbial methanogenesis in some settings (McIntosh et al., 2010; Tyne et al., 2021). Preliminary research on H_2 storage suggests that this may also promote microbial activity (Dopffel et al., 2021).

The inflow of groundwater into mines and pumping to prevent these inflows also represents a substantial perturbation to deep groundwater flow. There is no comprehensive global database of inflow rates but values of 1 to 1,000 L/s have been documented (Dong et al., 2021; Greene et al., 2008; Winter et al., 1983). If an inflow rate of 10 L/s is representative of the globe's 6,000 active mines (Maus et al., 2020), this would result in 1.9 km^3/yr, which is similar to the current rate of global oil production. These waters are often released to surface waters as the lower permeability environment associated with many mines prevents subsurface disposal. Changes in hydrogeochemical conditions and microbial communities in the vicinity of mines will result from downwelling of meteoric water and upwelling of older, more saline water (Figure 1).

The Future of the Subsurface

Humanity's use of the subsurface over the next century is expected to increase to address climate change and energy security. This will include production of lithium, helium, and geothermal energy, along with storage and production of hydrogen, storage of compressed air and geologic CCS. CCS is arguably the most important of these projected uses in terms of reducing greenhouse gas emissions, with many of the studies examining the capacity to sequester carbon in the subsurface focusing on estimation of the volume of porosity in sedimentary basins suited for this purpose (Benson & Cole, 2008; Krevor et al., 2023; Zoback & Smit, 2023). Additional capacity exists in mafic and ultramafic rocks(Gislason & Oelkers, 2014) but uncertainty exists around the ability to inject large volumes of fluid into these often low permeability environments (Fisher, 1998). Global capacity in sedimentary basins may exceed 60,000 Gt (Kearns et al., 2017), which far exceeds the 220 to 2500 Gt that may need to be sequestered. Comparing this amount to historical fluid production and injection and fluid fluxes provides a different perspective.

Although some of the injected CO_2 may be quickly mineralized in rock or dissolved in fluids (Benson & Cole, 2008), if sequestered as a separate phase, 2,000 Gt of CO_2 is equivalent to a volume of ~3,300 km^3, if a density of 600 kg/m^3 is assumed for CO_2. This volume of fluid is an order of magnitude larger than cumulative historical global oil production. A proposed annual sequestration rate of 6 Gt/yr (~10 km^3/yr) of CO_2 by 2050 would occur at a rate 50% greater than global oil production in 2022 (Zoback & Smit, 2023) and similar to the maximum estimated global flux of deep groundwater (Ferguson et al., 2023). CO_2 injection is likely to be concentrated geographically, near anthropogenic sources of CO_2 (e.g., power plants) and in areas where suitable subsurface reservoirs exist (Bachu, 2003). Experience from oil and gas production and associated co-produced water management indicates that even where fluid budgets are close to balanced, large hydraulic head changes will occur at local scales near injection wells resulting in substantial changes in regional groundwater flow systems (Barson, 1993; Jellicoe et al., 2022) and, in some cases, induced seismicity (Peterie et al., 2018). Such impacts have yet to be documented in CCS projects but responsible caution will need to be exercised if use of the subsurface for CCS becomes more extensive.

Produced water from oil production and other sedimentary brines have been proposed as sources of lithium (Kumar et al., 2019; Munk et al., 2016). Lithium extraction from sedimentary basin brines will only be viable if large fluid volumes can be produced, likely from wells producing at several times the rate of a typical oil well (Marza et al., 2023). The median Li concentration in sedimentary basin brines in the USA is 5 mg/L (Blondes et al., 2016) and we assume that concentrations in similar environments around the globe are comparable. At this concentration, 20 km^3 of brine would be required to produce an amount equal to global Li production of 100,000 tpy in 2022 (USGS, 2023), an amount similar to current combined annual oil and associated produced water volumes (Figure 2).

Geothermal electricity production of 1,050 TW h/yr using binary technology in conventional and enhanced geothermal systems has been projected for 2050 using an integrated assessment model (van der Zwaan & Dalla Longa, 2019). Binary geothermal systems require approximately 610,000 USGPD/MW_e (= 6.53 x 10^7 m^3/yr/MW_e) (C. E. Clark et al., 2010), indicating that 75 km^3/yr of fluid would need to be produced to support the projected level of geothermal electricity production. This target represents a large expansion of geothermal capacity but would only account for a small fraction of current electricity generation, at 67 TWh/yr compared to the overall generation of 23,000 TWh in 2019 (IEA, 2021a). Large increases in production and injection of fluids will be required to upscale direct-use geothermal applications, which currently provide nearly 300,000 GWh/yr of heat, although that number includes many “closed” systems which extract without production or injection of fluid(Lund & Toth, 2021).

Despite the large volume of pore space in the subsurface globally, there will inevitably be competition between different applications (Ferguson, 2013). All developments here will benefit from the presence of elevated permeability and porosity to allow for larger injection and/or extraction rates. In some cases, such as geothermal power production and CCS, overlapping temperature ranges may allow for synergistic developments (Randolph & Saar, 2011). In other cases, previous developments may complicate other types of subsequent uses. For example, strata that have previously been extensively developed for oil and gas may not be appropriate for CCS or H_2 storage because of the possibility of leakage through older wells (Gasda et al., 2014). Reservoirs that have a history of injection of fluids that have spent time at the surface are likely to have cooled, which will have altered their potential to produce geothermal power or sequester carbon (Ferguson & Ufondu, 2017). The lack of characterization of impacts of fluid production and injection will be a challenge as we look to repurpose portions of the subsurface that have been previously developed. Whether this competition restricts development or expands that volume of subsurface use is unclear.

Similar magnitudes of changes to subsurface fluid budgets and associated changes in hydraulic gradients due to extraction of groundwater and hydrocarbons and injection of various fluids for storage and disposal are occurring orders of magnitude more rapidly than geological drivers. For example, groundwater flow in the Mannville Group of the central portion of the Williston Basin, Canada appeared to have been stable for millions of years, even through multiple glacial cycles (Cheng et al., 2021), yet operation of injection wells since the 1960s for disposal of oilfield produced waters has resulted in substantial disruption of background groundwater flow patterns (Jellicoe et al., 2022). The implications of these changes to groundwater flow on solute transport and microbial activity will likely occur with substantial time lags and may persist well into the future even once the anthropogenic perturbation ceases due to the long-time scales associated with hydraulic diffusion (Bredehoeft & Durbin, 2009). Responses of shallow groundwater systems to new boundary conditions associated with climate change will likely take decades to centuries (Cuthbert et al., 2019). Fluids in the deeper subsurface are slow to respond to shifts in climate and topography, with regional aquifer systems typically having hydraulic response times of thousands to millions of years (Rousseau-Gueutin et al., 2013). Solute transport responses typically take place over longer time periods due differences between rates of advection and hydraulic diffusion(Ferguson et al., 2023). Evidence for increases in subsurface paleofluid fluxes, solute transport and microbial activity have been tied to geological events such as continental scale glaciations (McIntosh et al., 2012) or extensive denudation and incision by large rivers (Kim et al., 2022; Li et al., 2023).

There has been considerable debate about how the Anthropocene will appear in the geologic record but this has largely focused on depositional processes and what markers will delineate the shift from the Holocene to Anthropocene (McCarthy et al., 2023; Zalasiewicz et al., 2011). Anthropogenic activities in the deep subsurface will also leave a mark in the geologic record. Wells and boreholes will likely be rarely encountered due to their small diameter and large spacing (Zalasiewicz et al., 2014). Hydraulic fractures, which commonly extend 50 to 100 m from the wellbore (Davies et al., 2012), will increase the footprint of human activities slightly but activities associated with more permeable strata, where fluids can migrate greater distances, are likely to leave more extensive evidence. Transport of fluids from injection into conventional oil and gas reservoirs commonly reaches several 100 m (Craig Jr et al., 1955; Wassmuth et al., 2009) and transport of CO_2 of distances of several 100 m have been observed in CCS projects (Ringrose, 2018). Contaminant plumes with greater extents can develop in shallower groundwater systems under background hydraulic gradients(Van der Kamp et al., 1994) but will be less common in deeper systems due to the lower hydraulic gradients unless injection or pumping wells are operated for long time periods (Jellicoe et al., 2022). Transport can be further enhanced by the presence of leaky wells. Instances are documented where migration of fluids over distances of several 100 m have occurred through leaky wells in waterflooding (Eger & Vargo, 1989) and hydraulic fracturing operations(DiGiulio & Jackson, 2016). Contaminant plumes in shallow groundwater systems can persist for decades or longer

(Essaid et al., 2011) and timescales in the deep subsurface could be even longer due to the smaller geochemical fluxes available to support geochemical transformations.

Secondary minerals, such as barite, carbonates and sulfides are commonly precipitated following the injection of water for secondary recovery of oil (i.e. waterflooding), hydraulic fracturing or for disposal of produced water from oil and gas operations (Bennion et al., 1998; Engle & Rowan, 2014; Jew et al., 2017). CCS operations are predicted to result in bleaching of sandstones and release of trace metals due to removal of hematite (Bickle & Kampman, 2013), along with precipitation of halite (Muller et al., 2009). At a smaller scale, calcite and sulfide precipitation may occur due to stimulation of microbial activity by materials introduced during drilling and well construction (Pidchenko et al., 2023). The isotopic signatures of these minerals precipitated due to injection of fluids may differ from similar minerals precipitated under background conditions (Śliwiński et al., 2017). The rock record in environments that have experienced fluid flow events that resulted in precipitation of secondary minerals driven by changes in solute fluxes, salinity, redox conditions and microbial communities can provide some insights into how anthropogenic activities in the deep subsurface are being preserved.

Conclusions

Extraction of groundwater as well as production and injection of fluids by the oil and gas industry have become important components of the global subsurface fluid budgets during the Anthropocene. Increased use of subsurface fluids for extraction of energy and mineral resources and associated pore space for storage of alternative energy and anthropogenic waste has been proposed to confront climate change. While there is likely adequate subsurface storage, the fluxes of fluids involved with CCS, geothermal energy production and lithium extraction will be substantial, likely exceeding current levels associated with the oil and gas industry.

The subsurface and its pore space has often been viewed as a resource(Melo Zurita et al., 2018) rather than part of the Earth system. Over the past two decades, there has been an increase in the awareness of the microbial communities that inhabit the deep subsurface of depths of up to a few km (Bar-On et al., 2018; Magnabosco et al., 2018; McMahon & Parnell, 2014). This has been accompanied by questions about how the deep subsurface fits within the larger Earth system in terms of microbial life and associated water and geochemical fluxes (Ferguson et al., 2021, 2023; Lollar et al., 2019; Warr et al., 2018). As we stand at the precipice of the energy transition, we have the opportunity to develop the deep subsurface in a manner that allows us to study its natural functions and response to anthropogenic perturbations to minimize human impacts and build understanding, synergies and resilience.

Data Availability Statement

No new data was generated or compiled to support writing of this commentary.

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