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Tracing enhanced oil recovery signatures in casing gases from the Lost Hills oil field using noble gases

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ABSTRACT

Enhanced oil recovery (EOR) and hydraulic fracturing practices are commonly used methods to improve hydrocarbon extraction efficiency; however, the environmental effects of such practices remain poorly understood. EOR is particularly prevalent in oil fields throughout California where water resources are in high demand and the disposal of large volumes of produced water may affect groundwater quality. Consequently, it is essential to better understand the fate of injected (EOR) fluids in California, and other subsurface petroleum systems, as well as any potential effect on nearby aquifer systems. Noble gases can be used as tracers to understand hydrocarbon generation, migration, and storage conditions, as well as the relative proportions of oil and water present in the subsurface. In addition, a noble gas signature diagnostic of injected (EOR) fluids can be readily identified. We report noble gas isotope and concentration data in casing gases from oil production wells in the Lost Hills oil field, northwest of Bakersfield, California, and injectate gas data from the Fruitvale oil field, located within the city of Bakersfield. Casing and injectate gas data are used to: 1) establish pristine hydrocarbon noble-gas signatures and the processes controlling noble gas distributions, 2) characterize the noble gas signature of injectate fluids, 3) trace injectate fluids in the subsurface, and 4) construct a model to estimate EOR efficiency. Noble gas results range from pristine to significantly modified by EOR, and can be best explained using a solubility exchange model between oil and connate/formation fluids, followed by gas exsolution upon production. This model is sensitive to oil–water interaction during hydrocarbon expulsion, migration, and storage at reservoir conditions, as well as any subsequent modification by EOR.

1. Introduction

Noble gases are excellent tracers of a variety of subsurface fluid flow processes due to their inert nature and distinct isotopic signatures. Noble gas isotopes and relative concentrations can be used to provide limits on the volumes of differently sourced fluids that have contributed to any particular system (Ballentine et al., 1991, 1996; Ballentine and Burnard, 2002). Terrestrial reservoirs (i.e., atmospheric, crustal and mantle) have diagnostic noble gas isotopic compositions, and fluids derived from each reservoir can be differentiated. Noble gases from fluids in sedimentary basins have been used to successfully quantify physical exchange mechanisms between water, oil and gas phases in conventional and unconventional hydrocarbon systems (Ballentine and Burnard, 2002; Hunt et al., 2012; Prinzhofer, 2013; Darrah et al., 2014, 2015; Wen et al., 2015, 2016; Barry et al., 2016, 2017; Byrne et al., 2018).

Noble gases are also useful tracers of fugitive natural gases detected in groundwater (Darrah et al., 2014, 2015; Wen et al., 2015; Harkness et al., 2017) and for understanding the effects of CO_2 injection and EOR (LaForce et al., 2014; Győre et al., 2015; Sathaye et al., 2016). To date, the use of noble gas signatures as tracers of reservoir processes in oil dominated systems is not well-developed, and requires precise characterization of noble gas signatures of oil reservoir fluids. However, subsurface hydrocarbon systems are intrinsically complex, marked by multiphase interactions (e.g., Barry et al., 2017) and affected by a range of natural geologic and anthropogenic processes. As a result, determining proportions of gas, oil, and formation water is difficult using geophysical (e.g., seismic, wireline logs, continuous core) and traditional geochemical

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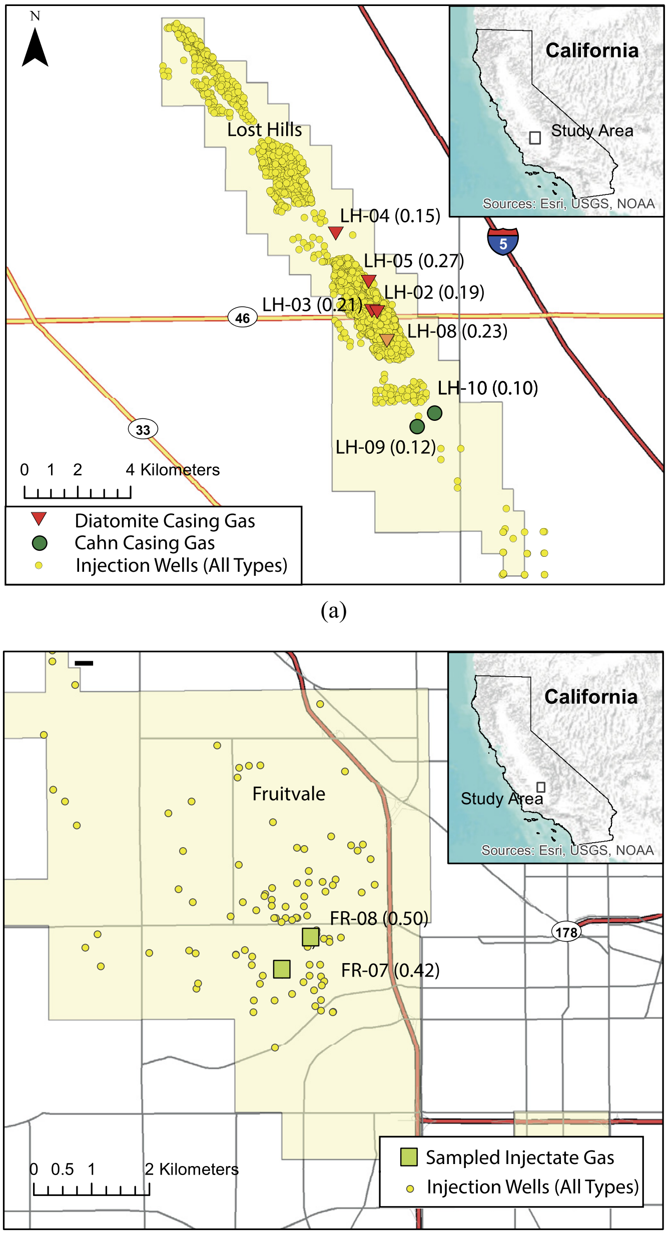
techniques (Batzle and Wang, 1992; Schoell, 1980). For example, geochemical variability within a hydrocarbon system is controlled by the timing and origin of hydrocarbon charge, secondary fluid migration, and the relative distribution of regional trapping structures. Further complicating these signatures is the superimposed effect of EOR techniques, including steam or CO_2 flooding, and unconventional techniques such as hydraulic fracturing (e.g., Darrah et al., 2014).

In this study, a novel geochemical approach is used to differentiate between source and secondary (EOR) geochemical features in an actively producing hydrocarbon system. This distinction is critical, as it provides the necessary baseline values for fingerprinting any fugitive hydrocarbons that might be identified in nearby aquifer systems, which are valuable natural resources as a source of water supply for drinking water and agricultural irrigation (Mount et al., 2014). A primary goal of the California State Water Resource Control Board's (SWRCB) Oil and Gas Regional Groundwater Monitoring Program (RMP) is to determine if any fluid exchange has occurred between regions affected by oil and gas activities and the surrounding groundwater (Taylor et al., 2014). The RMP will investigate approximately 100 onshore oil fields, thus providing information to resource management agencies about relative risks to groundwater. This study utilizes noble gas concentrations and isotope ratios in order to understand the extent of exchange between oil and formation waters. Our models describe how noble gas concentrations and elemental ratios evolve as 1) natural formation waters (i.e., air saturated water [ASW]) interact and exchange with oil in a pristine system, and 2) what the secondary effects of human-induced EOR are on the noble gases within a subsurface petroleum system.

2. Lost Hills production history

Oil was discovered in the Lost Hills area in 1910, which is located in the southwestern portion of San Joaquin Valley, approximately 220 km northeast of Los Angeles and 70 km northwest of Bakersfield, California, USA (Long et al., 2015). The Lost Hills field currently produces oil, with no separate hydrocarbon gas phase (or 'gas-cap') being encountered. Details about geologic and depositional history are provided in the Supplementary Material.

Oil and gas operators commonly inject water and steam into subsurface petroleum-bearing rocks (e.g., Tulare Formation, Etchegoin Formation) throughout the San Joaquin Valley in order to promote secondary recovery of hydrocarbons and to maintain adequate fluid pressures in petroleum reservoirs. Injected fluids commonly consist of briny produced, surface or well water. The Tulare Formation was extensively steamflooded, beginning in 1964. The Diatomite, within the Monterey Formation, was waterflooded, hydraulically fractured, and subjected to CO_2 injection, with the earliest hydraulic fracturing occurring in 1962 (Land, 1984). All wells where injection has occurred (since 1977) in the Lost Hills field are shown in Fig. 1a. Tracers injected into the Belridge Diatomite of the Monterey Formation have been shown to breakthrough to the oil producing wells in less than one month, which may indicate a naturally fractured reservoir (Zhou et al., 2002). The total number of injection wells (within a 100 and 500 m radius of the sample well) has been tabulated in Table 1 along with aggregate injection volumes. Supplementary Figs. S3–S7 show the injection history of Lost Hills (since 1977) and the proximity to wells sampled in this study. Digitized records of injection volumes per well prior to 1977 were not available, but for the entire Lost Hills field, injection occurring during 1952–1976 accounted for about 2% of total historic injections.



(a)

(b)

Fig. 1. a) Map showing the location of where casing gases were collected in the Lost Hills Oil Field. Diatomite casing gases are shown as red triangles apart from sample LH-08, which is shown as an orange triangle (as it plots distinctly in several subsequent figures). Cahn casing gases are shown as green circles. The location of injection (EOR) wells are also shown as (small) yellow circles. This labeling scheme is used in all subsequent figures. $^{20}Ne/^{36}Ar$ values are shown in parentheses next to each well name; the highest $^{20}Ne/^{36}Ar$ values were measured in the densest regions of injection, whereas the lowest $^{20}Ne/^{36}Ar$ values have limited injection in their vicinity. b) Map of Injectate gases collected (large green squares) in the Fruitvale Oil Field and their proximity to all other injection wells in the region (small yellow circles). $^{20}Ne/^{36}Ar$ values are shown in parentheses next to each well name. Notably, the two injectate samples that we collected had high (air-like) $^{20}Ne/^{36}Ar$ values. (For interpretation of the colors in the figure(s), the reader is referred to the web version of this article.)

Formation water at Lost Hills has salinity between 0.54 and 0.60 M NaCl and an average reservoir temperature of 57 °C. All oil gravities (expressed in American Petroleum Institute (API) gravity units) are homogeneous at approximately 23.1, apart from sample 'LH-05', which has an API of 21.5. All temperature, salinity and API data are taken from ($n = 7$) well-logs in the Lost Hills area. Heavier oil occurs in the (overlying) Tulare Formation (12–18 API).