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A statistical analysis of well production rates from UK oil and gas fields – Implications for carbon capture and storage

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ABSTRACT

The number of wells required to dispose of global CO_2 emissions by injection into geological formations is of interest as a key indicator of feasible deployment rate, scale and cost. Estimates have largely been driven by forecasts of sustainable injection rate from mathematical modelling of the CO_2 injection process. Recorded fluid production rates from oil and gas fields can be considered an observable analogue in this respect. The article presents statistics concerning Cumulative average Bulk fluid Production (CBP) rates per well for 104 oil and gas fields from the UK offshore region. The term bulk fluid production is used here to describe the composite volume of oil, gas and water produced at reservoir conditions. Overall, the following key findings are asserted: (1) CBP statistics for UK offshore oil and gas fields are similar to those observed for CO_2 injection projects worldwide. (2) 50% probability of non-exceedance (PNE) for CBP for oil and gas fields without water flood is around 0.35 Mt/yr/well of CO_2 equivalent. (3) There is negligible correlation between reservoir transmissivity and CBP. (4) Study of net and gross CBP for water flood fields suggest a 50% PNE that brine co-production during CO_2 injection could lead to a 20% reduction in the number of wells required.

1. Introduction

There has been on-going discussion in the literature concerning the number of injection wells that will be needed to store global CO_2 emissions in geological formations (Ehlig-Economides and Economides, 2010; Cavanagh et al., 2010; Hosa et al., 2011; Gammer et al., 2011). Confidence concerning estimates of number of wells required can be increased by consideration of previous experience. However, commercial-scale CO_2 injection data remains scarce (Michael et al., 2010, 2011; Hosa et al., 2011). Consequently, current estimates heavily rely on numerical simulation (e.g., Pickup et al., 2011; Jin et al., 2012; Zhou et al., 2012). A particular issue with numerical simulation concerns the excessive grid-resolution required to ensure numerically converged results (Pickup et al., 2012). This in turn leads to prohibitive computational requirements in the context of sensitivity analysis for uncertainty propagation (Mathias et al., 2013a; Hedley et al., 2013) although this problem can be partially alleviated by the use of simplified analytical solutions (e.g., Mathias et al., 2011b, 2013b).

This article seeks to gain further insight concerning the estimation of CO_2 injection rates by undertaking a statistical analysis of production data from 104 UK offshore oil and gas fields (DECC, 2013) (see Fig. 1). The conclusions from this work provide new information for forecasting likely injection rates, and therefore numbers of wells, for future CO_2 storage projects located on the UK continental shelf.

The article commences with an explanation concerning the need and methodology for converting data for standard conditions (60 °F and 14.7 psi) to an equivalent combined volumetric flow rate of oil, gas and water at reservoir conditions. A discussion is then provided to explain the choice of using the cumulative average production rate after 10 years. Production data statistics for UK offshore oil and gas fields are compared with those for CO_2 injection projects worldwide. Water flood data are used to gain further insights concerning the usefulness of brine co-production during CO_2 injection. An investigation is then performed to look at how production statistics vary for different reservoir types. Finally, the article summarises and concludes.

2. Formatting of DECC production data

Time series data for all UK offshore oil and gas fields can be obtained from DECC (2013) (UK Department of Energy and Climate Change) including both monthly production and injection data for oil, gas and water. An example of such a data set is shown for the Balmoral oil field in Fig. 2a. The DECC (2013) data is reported at

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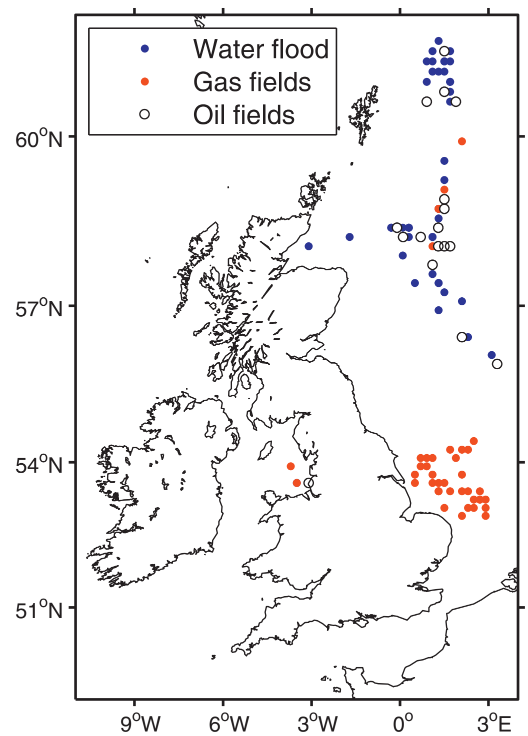

Fig. 1. Map of UK showing locations of the oil and gas fields studied. In the legend, "water flood" refers to oil fields where water injection has been used and "oil fields" refer to oil fields where water injection has not been used.

standard conditions (SC), i.e., 60 °F and 14.7 psi (Ahmed, 2001, p. 33). Also note to obtain an average production rate per production well it is necessary to divide the DECC (2013) data by the number of production wells in the field. For example, the Balmoral field has 14 production wells (DECC, 2007).

Note that the number of production wells in a given field often increases with field life. However, the history of well development for each field studied was not available for this investigation.

At reservoir conditions (RC) the solubility of gas in oil is much higher. Once the oil is brought to SC, the gas solubility is significantly reduced and gas comes out of solution. Most of the gas produced in UK oil fields has been derived by this process. In reservoir engineering it is typical to quantify gas solubility in terms of a gas–oil-ratio at SC, R_s, which is measured in standard cubic ft of gas per standard barrel of oil (SCF/BBL). Fig. 3a shows a plot of R_s as a function of pressure for the Balmoral field, assuming a correlation function presented by Glaso (1980) (see Eq. (2.73) of Ahmed, 2001). Note that beyond 1460 psi, R_s remains constant. This critical pressure for a given oil and gas is referred to as the bubble point, defined as the pressure at which a bubble of gas appears on depressurising.

Also of interest is the gas expansion factor, E_g (−), defined as the volume of gas at SC divided by the volume of gas at RC. Fig. 3a also shows E_g for Balmoral according to the Peng and Robinson (1977) equation of state (EOS) assuming critical pressures and temperatures as calculated using the correlations of Standing (1977) (see Eqs. (2.18) and (2.19) of Ahmed, 2001). Note that E_g increases with increasing reservoir pressure due to the increase in gas density associated with compression.

A unit volume of oil at RC results in a smaller produced volume at SC due to the loss of gas from solution when the pressure is lowered. Also, at RC, once gas is dissolved an increase in reservoir pressure

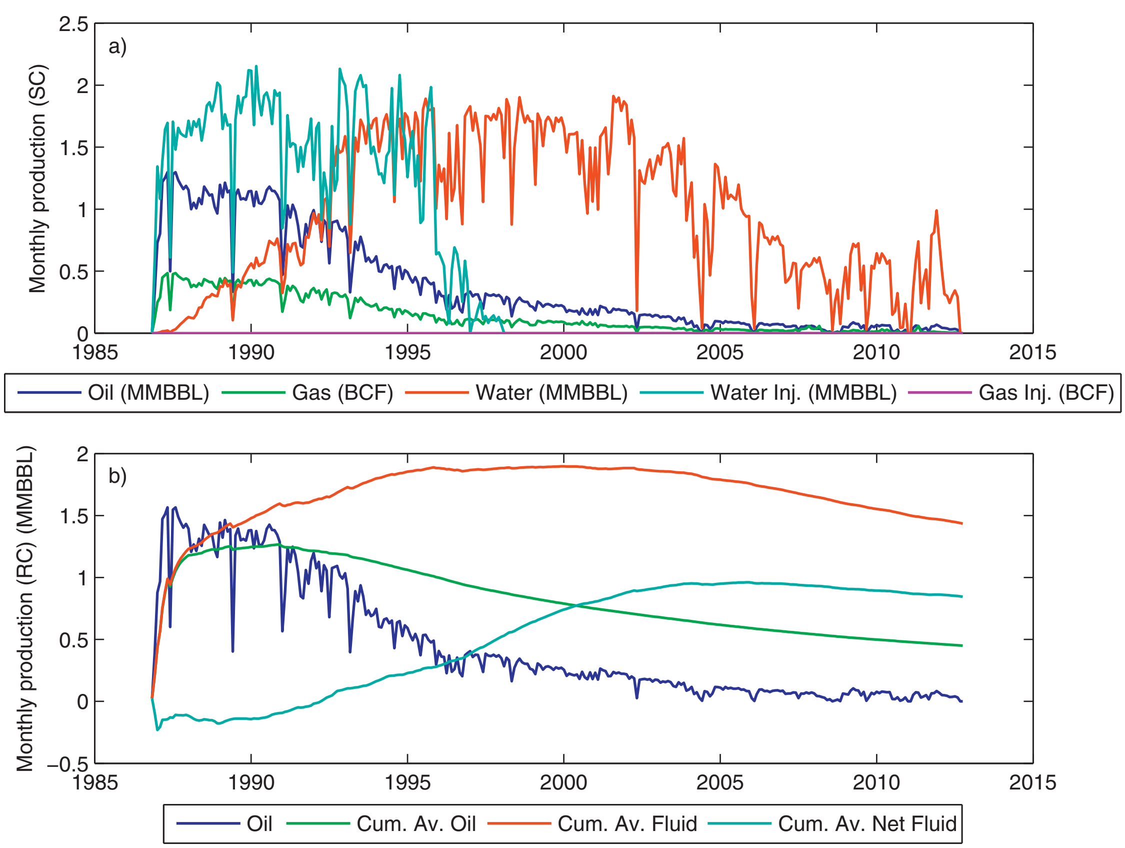

Fig. 2. Time series plot of monthly production for the Balmoral field. (a) Assuming standard conditions (SC). Note that data here are production data except for "Water Inj." and "Gas Inj.", which are injection data. (b) Assuming reservoir conditions (RC). Note that "Cum. Av." is an abbreviation for cumulative average and "Net Fluid" involves subtracting the injected water and gas.