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Enhanced Gas and Condensate Recovery: Review of Published Pilot and Commercial Projects

Wspomaganie wydobycia gazu ziemnego i kondensatu: przegląd opublikowanych projektów pilotażowych i komercyjnych

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ABSTRACT: The majority of the Ukrainian gas condensate fields are in the final stage of development. The high level of reservoir energy depletion has caused significant in situ losses of condensed hydrocarbons. Improving and increasing hydrocarbon production is of great importance to the energy independence of Ukraine. In this paper, a review of the pilot and commercial enhanced gas and condensate recovery (EGR) projects was performed, based on published papers and literature sources, in order to identify those projects which could potentially be applied to the reservoir conditions of Ukrainian gas condensate fields. The EGR methods included the injection of dry gas (methane), hydrocarbon solvents (gas enriched with C_2–C_4 components), or nitrogen and carbon dioxide. The most commonly used and proven method is dry gas injection, which can be applied at any stage of the field's development. Dry gas and intra-well cycling was done on five Ukrainian reservoirs, but because of the need to block significant volumes of sales gas they are not being considered for commercial application. Nitrogen has a number of significant advantages, but the fact that it increases the dew point pressure makes it applicable only at the early stage, when the reservoir pressure is above or near the dew point. Carbon dioxide is actively used for enhanced oil recovery (EOR) or for geological storage in depleted gas reservoirs. In light of the growing need to reduce carbon footprints, CO_2 capture and sequestration is becoming very favourable, especially due to the low multi-contact miscibility pressure, the high density under reservoir conditions, and the good miscibility with formation water. All of these factors make it a good candidate for depleted gas condensate reservoirs.

Key words: enhanced condensate recovery, dry gas injection, solvent gas injection, nitrogen injection, carbon dioxide injection, CO_2 sequestration.

STRESZCZENIE: Większość ukraińskich złóż gazu kondensatowego znajduje się w końcowej fazie zagospodarowania. Wysoki poziom wyczerpania energii złożowej spowodował znaczne straty in situ skroplonych węglowodorów. Duże znaczenie dla niezależności energetycznej Ukrainy ma usprawnienie i zwiększenie wydobycia węglowodorów. W niniejszym artykule dokonano przeglądu pilotażowych i komercyjnych projektów wspomagania wydobycia gazu ziemnego i kondensatu (EGR) na podstawie opublikowanych artykułów i źródeł literaturowych w celu zidentyfikowania tych, które mogą znaleźć zastosowanie w warunkach występujących w ukraińskich złożach gazowo-kondensatowych. Metody EGR obejmują zatłaczanie: suchego gazu (metanu), rozpuszczalników węglowodorów (gaz wzbogacony składnikami C_2–C_4), azotu i dwutlenku węgla. Najpowszechniej używane, sprawdzone i szeroko stosowane jest zatłaczanie suchego gazu, które można wykorzystać na każdym etapie zagospodarowania złoża. Na pięciu ukraińskich złożach zostało wdrożone zatłaczanie suchego gazu i obieg wewnątrz odwiertu, ale ze względu na konieczność zablokowania znacznych wolumenów gazu przeznaczonego do sprzedaży obecnie metoda ta nie jest brana pod uwagę do komercyjnego zastosowania. Azot ma wiele istotnych zalet, ale fakt, że powoduje zwiększenie ciśnieniowego punktu rosy, sprawia, że można go stosować tylko na wczesnym etapie, gdy ciśnienie złożowe jest wyższe od punktu rosy. Dwutlenek węgla jest aktywnie wykorzystywany do wspomagania wydobycia ropy naftowej (EOR) lub do geologicznego składowania w sczerpanych złożach gazu. W świetle rosnących potrzeb w zakresie redukcji śladu węglowego wychwytywanie i sekwestracja CO_2 stają się bardzo korzystne, zwłaszcza ze względu na niską wartość ciśnienia mieszalności przy wielokrotnym kontakcie, dużą gęstość w warunkach złożowych oraz dobrą mieszalność z wodą złożową. Wszystko to sprawia, że jest to dobry kandydat do zastosowania w sczerpanych złożach gazu kondensatowego.

Słowa kluczowe: wspomaganie wydobycia kondensatu, zatłaczanie suchego gazu, zatłaczanie płynów rozpuszczalnikowych, zatłaczanie azotu, zatłaczanie dwutlenku węgla, sekwestracja CO_2.

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Introduction

Almost all of the gas and condensate fields in Ukraine are produced by primary depletion. About 80% of the gas production of the largest state-owned gas operating company, Ukrgazvydobuvannia, comes from 23 fields, or 18% of the company's total assets. The level of depletion for these 23 fields is 75% or higher (Firman, 2019). The injection of different agents, such as hydrocarbon or non-hydrocarbon gasses or even chemical agents, for the evaporation and displacement of condensed liquid hydrocarbon fractions is one of the potential ways to increase current production rates and stop the decline.

The review summarises the information from the literature on the subject and public sources on the application of the main enhanced gas and condensate recovery methods, with the purpose of providing recommendations for selecting the most technically and economically suitable method.

Dry gas injection (gas cycling)

Dry gas injection is the first and most widely used EGR method. Dating back to the 1930s, the re-injection of captured dry gas started in the USA. During the Second World War, the demand for liquid hydrocarbons increased significantly, resulting in 37 gas-cycling operating units being implemented in reservoirs with a relatively low condensate yield of 150–180 g/m^3. After the war the drop in gas prices and the demand for light liquids reduced the sites in operation to those with a potential condensate yield of 250 g/m^3 or higher. At the same time, the transition towards non-hydrocarbon gasses began.

Pressure maintenance has been implemented in only five of the Ukrainian reservoirs: gas recycling in T-1 of the Kulychykhinske field, T-1 of the Tymofiivske field, and S-5 of the Kotelevske field. In the Berezivske field, there is an intra-well crossflow of gas from the high-pressure, low-C_{5+}-yield V-16 reservoir into the low-pressure, high-C_{5+}-yield S-5 reservoir. The K-30 reservoir of the Novotroitske field is still being developed by depletion although gas recycling has ended there (Bikman, 2006, 2017).

Kaybob (Alberta, Canada)

The largest Canadian gas condensate field was discovered in 1961 in Alberta (Viakhirev et al., 2002; Atchley et al., 2008). The reservoirs are associated with porous reef dolomites and tight carbonates with 104 billion m^3 of initial gas and 48 million tonnes of condensate in place. The vertical stratigraphic heterogeneity resulted in net pay variations from 0 up to 110 m. The reservoir has an abnormally high pressure of 32.4 MPa and a temperature of 114°C for the depth range of 2300–2500 m. The fluid system was under-saturated with highly boiling hydrocarbons, resulting in a low dew point pressure of 23.4 MPa. Nonetheless, in the pressure range between 32.4 and 23.4 MPa, no liquid phase is formed in the reservoir; further depletion leads to rapid condensation with a maximum drop-out at 8.1 MPa, resulting in an oil saturation of 5%. According to calculations, the condensate recovery factor until the abandonment pressure of 4.1 MPa is reached will be 65%, which is caused by the low dew point pressure leading to 17% condensate recovery until the condensation starts. Numerical simulations and material balance evaluations for different recovery methods (depletion, dry gas, water, and rich gas injection) have shown that the most economically efficient is partial gas injection.

Cotton Valley (Louisiana, USA)

A classic anticline-shaped trap with five reservoirs formed in the Upper Jurassic constitutes the Cotton Valley Field in Louisiana, USA. One of the reservoirs (Bodcaw Sand) had been under primary depletion since 1937, but due to complex phase behaviour, dry gas injection only started in 1941, when the reservoir pressure declined from an initial 27.4 MPa (equal to the dew point pressure) to 22.0 MPa. Out of the 50 wells that were drilled, some were used for surveillance of the injection efficiency. The declining trend of C_{4+} content that exactly followed the trend prior to dry gas injection indicates two possible factors: either dry gas break-through or additional condensate dropout due to the continuous decline of reservoir pressure – by 2.5 MPa even during gas injection. Until 1945, 50% of the wet gas was produced without significant mixing with dry gas, apart from few wells, which indicates that no major gas break-through took place. Dry gas front movement was well-correlated to physical experiments on electrolythical models. At the time Miller and Lents published their paper, continuing the gas cycling could have resulted in 85% condensate recovery (Miller and Lents, 1946).

Dukhan (Qatar)

The oil and gas reservoir Dukhan, consisting of late Jurassic carboniferous deposits, is represented by a 70-km anticline with a 210-m gas cap that is in equilibrium with an oil leg of the same reservoir. Discovered at the end of 1930s, oil production continued until the beginning of the 1950s, leading to a pressure decline of 4.1 MPa and significant gas cap expansion, liquid condensation, and blockage of the pore space. In the mid-1970s water flooding increased the reservoir pressure by 0.3–0.7 MPa. Starting from 1998, gas cycling initiated in the gas cap with estimated condensate-in-place volume of 200 million m^3 through several wells in the crest of the structure. The keys to the gas cycling project's success were (Al-Ansari et al., 2008):

- tracer injection tests;
- regular surface sampling and composition control;
- regular well testing;
- reservoir pressure measurement and monitoring;
- accurate production allocation for condensate recovery measurements, and
- detailed compositional models and numerical simulation.

Karachaganak (Kazakhstan)

Karachaganak field is one of the largest gas condensate fields in the world, associated with a heterogeneous carbonate reef and platform 30 × 15 km and located on the northern margin of the Pricaspian Basin. The field is divided into three principle reservoirs with thicknesses ranging from 700 to 900 m. The first and second reservoirs are gas condensate, whilst the third is an oil rim between GOC at –4950 m and WOC at –5165 m. The field, with near-critical gas condensate fluid, was discovered in 1979 and has been in production since 1985; in 2004 partial gas re-injection was implemented at a 40% replacement ratio for pressure maintenance, with the current focus on oil-rim development. The initial pressure ranges from 520 to 595 bar with reservoir temperatures between 70 and 95°C. Initial volumes in places were estimated at 1.3 trillion m^3 of gas and 1.2 billion tonnes of condensate and oil. The gas condensate is very rich, with a variable yield ranging from $0.5 \cdot 10^{-3}$ m^3/m^3 at the top of the structure to $1.25 \cdot 10^{-3}$ m^3/m^3 at the GOC. The gas is sour, with an H_2S content of between 3.5% and 5% and a CO_2 content of 5.5%. The reservoir's rocks have average porosities varying between 7.3% and 15.4% and a permeability of between 1.3 and 81.1 mD. The complex geological nature of the field – particularly the poor seismic quality, being affected by overlaying salt, the highly heterogeneous facies distribution and reservoir properties, the enhanced permeability (due to the presence of fractures) that does not correlate with porosity, and dolomite impact and extent – was tackled by an integrated geomodelling approach (Francesconi et al., 2012; Albertini et al., 2014; Tarantini et al., 2015; Kassenov and Kaliyev, 2016). Based on well logs and pressure data (XPT/RFT), depositional cycles were defined in addition to a seismic stratigraphic study (Bigoni et al., 2010), which helped to guide the layering in the geological model and to reproduce the gas break-through from injectors during gas cycling in numerical model. The availability of 25,000 plug samples with routine core analysis data allowed a reliable lithological model including porosity to be created, while the Winland pore-throat method was used in rock-typing based on the available permeability data. Water saturation was estimated from capillary pressure data coming both from MICP measurements and well log interpretation, which resulted in water saturation defined as a function of porosity and height above FWL. A simulation model was built with 380,000 active cells and represented by a 12-component EOS in ECLIPSE compositional simulator. Due to the huge net pay thickness and the size of the field, very coarse cells with later dimensions of 200 m and thicknesses of 15–20 m were used, affecting both the petrophysical properties and the simulation results. However, due to the huge volume of production data (rates, pressures, PLT and RFT, and well test results) and the performance of history matching on a macro and micro scale, an acceptable match quality was achieved, serving as the basis for gas injection optimisation (Tarantini et al., 2015). The optimisation was performed in several stages. First, the model was divided into nine partitions and gas injection was tested with different injection volumes and compressor counts. Second, the uncertainty of liquid production was evaluated. Finally, quadratic programming method was used to derive the maximum liquid production with minimum level of uncertainty.

Tymofiivske (Ukraine)

The T-1 reservoir of the Tymofiivske gas condensate field has been developed with dry gas cycling since 1993 (Bikman et al., 2011; Bikman, 2017). The reservoir from the Devonian age is characterised by sandstone with interlayers of mudstones and limestones and an average porosity of 14.2% and core permeability of up to 4000 mD. At an initial reservoir pressure of 44.6 MPa, initial gas in place of 18.4 billion m^3, 6.7 million tonnes of condensate (a potential condensate yield of 366 g/m^3), and 3.3 million tonnes of oil in the oil rim. As of early 2017, 21.4 billion m^3 of gas were produced, out of which 13.4 billion m^3 belong to the recycled gas via six injection wells. The cumulative condensate recovery is 3.2 million tonnes, out of which the incremental recovery due to gas cycling is estimated to be 500,000 tonnes. The key issue at the reservoir is the developing the oil rim and controlling water break-through from the aquifer.

Solvent gas injection

In the former USSR and now in Russia, the application of hydrocarbon solvents for hydrocarbon recovery has been actively studied (Gritsenko et al., 1980; Zakirov and Aliev, 1985; Ter-Sarkisov, 1997, 1999; Viakhirev et al., 2002; Ter-Sarkisov et al., 2015). The injection of gasses enriched by C_2–C_4 components increases the condensate volume and its saturation, enabling it to be mobile above critical saturations. Laboratory tests have found an efficiency of 3–12% of injected pore volumes of solvent for the condensate displacement depending on reservoir heterogeneity.

A search on onepetro.org yielded many published papers related to various problems:

- oil displacement with hydrocarbon and non-hydrocarbon solvents;
- evaporation and condensation processes at the displacement front;
- identification and calculation of miscibility conditions;
- laboratory and experimental results on miscibility and displacement, and
- numerical compositional simulation.

Due to significant number of papers, we will mention only one, with the most comprehensive summary of the different miscible displacement study methods (Shtepani et al., 2006).

In 1997, Bedrikovetsky applied a 1D analytical and semi-analytical approach for calculating the phase transitions and miscibility of the pilot LPG project at the Vuktylskoe gas condensate field (Timano-Pechorsk, Russia). During the first pilot injection, 26.000 tonnes of LPG rim was injected into one well, followed by dry gas. After two months, the condensate bank reached the first two production wells, increasing the condensate-to-gas ratio (CGR) from 43 to 65 g/m^3. The second condensate bank arrived 5–6 months after the injection started. This time there was no increase in the CGR, but the condensate was much heavier, with an additional condensate recovery of 1000 tonnes. Based on these results, different scenarios (volume of rim, duration, etc.) of LPG injection were evaluated; however, for all of them the incremental recovery never exceeded 20%. During the second pilot, dry gas was injected into three injection wells for two years, resulting in 695 million m^3 of gas injection in total. As a result, 237.000 tonnes of LPG and 54.000 tonnes of condensate were recovered; incremental recovery continued for a longer period than the base depletion case.

Nitrogen injection

A significant number of studies have been dedicated to the application of nitrogen for pressure maintenance in gas condensate reservoirs. Most of them were based on compositional numerical simulation models for real or synthetic simplified reservoirs (Kossack and Opdal, 1988; Siregar et al., 1992; Sanger et al., 1994; Saenger and Hagoort, 1998). The conclusions regarding nitrogen's efficiency vary between studies. The key advantages stem from the unlimited resource availability (air) and well-established production technology with stationary or mobile cryogenic, membrane, or adsorption units, and low equipment corrosion (Kondrat and Khaidarova, 2018). Among the potential limitations and disadvantages is that nitrogen significantly increases saturation pressure (Saenger and Hagoort, 1998), making it almost impossible to reach the first contact miscibility, or miscibility at any injected nitrogen concentration, since those pressures are usually higher than 80 MPa. Due to the increased dew point pressure, not only at the displacement front between the nitrogen and the reservoir gas, but also in the bypassed regions, increased liquid condensation can take place, leading to potentially greater hydrocarbon losses. On the other hand, in rich gas condensate systems, this can have a positive effect of reaching critical oil saturations at which the condensate will become mobile. Therefore, nitrogen injection is always recommended at reservoir pressures higher than the dew point, but must be evaluated when primary depletion has taken place.

One of the gas condensate fields in Abu Dhabi (Hamza et al., 2015) was developed with dry hydrocarbon gas cycling for about 15 years. Due to increased demand in sales gas, the decision was taken to add 20% nitrogen into the injection stream, beginning in June 2011. An intensive reservoir monitoring programme was put in place right after a mixture injection with tracer tests and a quarterly inspection of the composition of the produced gas. Nitrogen break-through happened in all production wells as early as six months after start of the injection, reaching 11 mole per cent in some wells after a year and a half. The same observation was made in the dry gas injection area, where the C_1:C_3 ratio drastically increased after three years. It is expected that nitrogen content will increase even after the production of nitrogen stops. Based on the monitoring results, which indicated faster nitrogen break-through times than originally estimated, the initial plan to stop injecting the mixture and start injecting pure nitrogen in the north-west part of the reservoir and pure dry gas in the rest was revised.

Nitrogen injection was proposed for two Ukrainian reservoirs: T-1 of the Tymofiivske field and T-1 of the Kulychykhivske field (Bikman et al., 2011). Both reservoirs were developed with dry gas cycling. Due to the gas injection, higher reservoir pressure was observed. There was a proposal to switch to nitrogen injection, which would also control water break-through from the aquifer. According to the economic evaluation, the investment of the additional surface equipment for nitrogen generation should pay off in one year; unfortunately, so far it has not been done.

Carbon dioxide injection

The requirements towards the reduction of CO_2 emissions and general environmental impact enforced by the Kyoto Protocol (UNFCCC, 1998) and the Paris Agreement (UNFCCC, 2015) made carbon dioxide a favourable agent for pressure maintenance and geological storage. In the USA,

CO_2 is widely used for EOR, but its application for enhanced condensate recovery is still a subject of scientific research (Al-Hashami et al., 2005; Shtepani et al., 2006; Gachuz-Muro et al., 2011; Soroush et al., 2012; Narinesingh and Alexander, 2016).

Gachuz-Muro et al. (2011) performed high-pressure/high-temperature condensate displacement laboratory experiments in naturally fractured reservoirs. CO_2 injection made minimum difference to depletion, while natural gas injection showed the highest condensate recovery. Soroush et al. (2012) performed a conceptual EOR simulation study for a dipping gas condensate model by injecting pure CO_2 and CO_2 water-alternating-gas injection (WAG), both in up-dip and down-dip miscible conditions. The down-dip CO_2 WAG and pure CO_2 injection had the same ultimate condensate recovery (approx. 81%), whilst for up-dip the recovery was only 60%. Shtepani (2006) evaluated CO_2 sequestration in depleted gas/condensate reservoirs, pointing out that CO_2 injection may enhance gas recovery through liquid re-vaporisation and pressure maintenance.

Narinesingh and Alexander (2016) performed a numerical simulation study on well placement and injection pattern optimisation using a simple 3D model for EGR and CO_2 sequestration in a gas condensate reservoir that was assumed to be depleted. The simulation showed that 20% of the CO_2 was trapped by hysteresis and another 40% was still in the supercritical state.

Maximum reduction of reservoir pressure without injection

In cases when gas injection for pressure maintenance is not feasible, in order to increase the recovery factors for both condensate and gas, the following technological solution could be implemented. Installing booster compressors before separation and gas treating facilities can lower the operating wellhead pressures and, as a result, the operating bottom-hole pressure at low values of reservoir pressures. Reducing reservoir pressure below the value of maximum condensation will activate reverse evaporation of retrograde liquids back into the gas phase, bringing back the well productivity due to reduced condensate banking. This technology was proposed for the VD-13 reservoir of the Zaluzhanske gas condensate field of Lvivgazvydobuvannia's initial gas in place operating unit (Kondrat and Kondrat, 2017; Kryvulia et al., 2017).

Conclusions

Enhanced condensate recovery may be performed under different conditions: miscible or immiscible, with hydrocarbon or non-hydrocarbon gasses. The most widely used and proven method is based on reinjecting (recycling) dry hydrocarbon gas (methane), with the purpose of maintaining pressure and re-evaporating condensed liquid fractions. The key advantages are high recovery factors and the flexibility of implementing it at any stage before, during, or after primary depletion. One disadvantage is the need to block huge volumes of sales gas during the cycling phase. Nitrogen is a good alternative to methane thanks to its availability and ease of production. Due to the increase in dew point pressure when mixed with most hydrocarbon fluid systems, it causes faster in situ liquid condensation, which limits its application to only cases when the reservoir pressure is higher or at the dew point. Nitrogen injection was proposed for a number of Ukrainian gas condensate fields (Tymofiivske and Kulychykhynske) and according to development plans and economic evaluations appears to be a good alternative to classic dry gas cycling, but so far it has not been implemented. Miscible conditions will not be established under common reservoir pressures. Injecting enriched gasses with C_2–C_4 fractions allows miscible displacement of condensate, leading to high recovery rates. The disadvantage, as in the case of pure methane injection, is the need to inject valuable hydrocarbons that otherwise could be sold. Carbon dioxide allows miscible displacement to build up at low reservoir pressures, and in terms of reducing emissions and guaranteeing proper geological storage it is a good and promising agent for enhanced condensate recovery coupled with sequestration. The key disadvantages are the need for a permanent source of CO_2 and high corrosion, which requires the use of special wellbore equipment.

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