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The Gas Huff-n-Puff PVT Experiment

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Abstract

The gas-based Huff-n-Puff (HnP) process is currently the dominating EOR process in tight unconventionals. This has happened as a result of operators looking to find new ways of increasing the production from their acreage, and several field implementations of the HnP process that have claimed success in doing so. Although the process has been studied largely the last years, there are still several aspects of the HnP process that are not yet fully understood, particularly its complex nature regarding the fluid phase behavior.

To help increase the understanding of the HnP process from a fluid perspective, we suggest a novel PVT experiment that captures the key characteristics of the HnP process, and provide all relevant stakeholders with the key performance indicator (KPI) that we refer to as the gas HnP recovery efficiency, defined as *"incremental volume of stock-tank oil (STO) produced per volume of surface gas injected"* (which in field terms is denoted incremental STB of oil produced per MMscf injected)

The proposed experiment is a hybrid of the traditional constant-volume injection (CVI) and constant-volume depletion (CVD) experiments, performed in an alternating sequence, to mimic the two periods of the HnP cycle: the injection period (huff), and the production period (puff).

The experiment is initiated by charging a PVT cell with a representative in-situ fluid composition at reservoir temperature (T_R) and initial reservoir pressure (p_{Ri}). A CVD experiment is then performed in pressure stages down to some minimum pressure that represent the pressure in the HnP target volume at time of implementation, e.g. close to the flow bottomhole pressure (FBHP). The final fluid composition from the initial CVD is then used as the starting point for the HnP PVT experiment, in which the first CVI, or huff period, is performed to some maximum pressure by injecting a specified gas. The subsequent CVD, or puff period, is then performed back down to the starting pressure of the HnP PVT experiment (close to the FBHP), completing the first of several HnP cycles.

The paper outlines a detailed explanation of the experimental procedure, including what information is recorded during each period, and how to interpret the recorded data with relevance to a field implementation of the HnP process.

Introduction

The gas HnP process is fundamentally different from a conventional/traditional displacement process. Conventional gas EOR is based on a configuration of designated injection- and production wells, whereas the HnP process is based on a single well in which injection and production are performed cyclically.

Carlsen et al. (2019a), and Mydland et al. (2020a), describe in detail why the HnP process is not a displacement process, and therefore how the conventional EOR theory becomes irrelevant. The HnP process achieves recovery by mixing the injected gas and the reservoir fluid by either vaporization of reservoir-fluid components into the gas phase when the system is in two-phase equilibrium, or by dissolving of the injected gas into the reservoir fluid when the system is single phase.

For conventional gas EOR processes, a central part of planning involves estimating the multi-contact minimum miscibility pressure (MMP_{MC}), as this is the lowest pressure for which the displacement front can sustain miscible displacement efficiency. As a result, multiple experiments have been suggested to get an estimate of the MMP_{MC}. The traditional, and most reliable, is the slimtube test (Yellig and Metcalfe 1980, Dindoruk et al. 2020). Other less accurate experiments have been introduced on the argument of being less time consuming and thus cheaper to perform than the slimtube (Christiansen and Haines 1987, Rao 1987).

There are currently no PVT experiments for the unconventional HnP process that are considered equally important as the slimtube experiment is for a conventional EOR process. Numerous HnP experiments on core plugs have been suggested (Liu et al. 2018, Hawthorne et al. 2019, Thomas et al. 2020, Tovar et al. 2021). However, the resulting data from such experiments can be challenging to use in tuning of the fluid model. Some of the experiments are made complicated by putting large emphasis on the impacts of the hydraulic fracturing (e.g. by cutting the core in half, by including proppants, by inducing large stress variations on the core, etc.), and/or are inconsistent from one core to the next as the residual amount of fluid in the core is difficult to measure accurately, yielding an uncertain material balance.

That is why we suggest this novel fluid experiment that captures the key characteristics of the gas HnP process, which are i) injection periods with associated pressure build up, ii) production periods with associated pressure drawdown, iii) a cyclic nature, and iv) a way of quantifying oil recovery versus number of cycles and/or volume (moles) of gas injected. Because we look at fluids only, and are not relying on small residual amounts left in core plugs, we obtain accurate measurements and tracking of the material balance throughout the experiment.

We emphasize that the proposed HnP PVT experiment assumes ideal conditions. It does not account for aspects such as time, spatial pressure variations, incomplete mixing, diffusion/dispersion, confinement/containment issues, fluid heterogeneity, and fracture/matrix flow. This means that the experiment provides an estimate of the HnP performance that represents an upper bound of what to expect in field.

Gas Huff-n-Puff PVT Fundamentals

There are two essential terms/concepts relevant for gas HnP PVT, mixing and vaporization.

Mixing: Imagine you have a cup half filled with *saltwater*. You top up the cup by adding half a cup of *freshwater*. Then you stir and remove half of the mixed fluid. Now you will have half of the original salt concentration in the cup. If you repeat this, you will eventually end up with only freshwater in the cup. This process is a *pure mixing*—or *dilution*—process at which the fluid composition in the cup, originally saltwater, converges to the composition of the injectant, here freshwater. This saltwater dilution process is analogous to what happens in the HnP PVT experiment if pressure cycling occurs above the minimum miscibility pressure by first contact (MMP_{FC}) (i.e. $p_{min} \geq MMP_{FC}$). The cup represents the PVT cell, the saltwater is the original reservoir fluid, and the freshwater is the injectant. At pressures greater than the MMP_{FC} the fluid in the PVT cell is *always* single-phase (regardless of the mixing proportion), resulting in a *pure mixing process*.

Vaporization: When the pressure interval in the HnP experiment is less than the MMP_{FC} ($p_{min} < p_{max} < MMP_{FC}$), the PVT cell *may* be occupied by a single-phase fluid at p_{max} for the first few cycles. However, the fluid will eventually turn, and remain, two-phase for the entire pressure interval [i.e. the mixture is always in a vapor-liquid equilibrium (VLE) state]. The oil recovery will then be a result of vaporization, in which the intermediate components from the oil vaporize into the gas phase (predominantly consisting of injection gas) during the injection (huff) periods, and followingly are produced as solution oil in the gas phase during the production (puff) periods. This would be a *pure vaporization process*.

We believe that the components extracted from the reservoir fluid, which turns into stock-tank barrels of oil at the surface, are recovered mainly from an immobile oil phase in the reservoir. This implies that the fluid system in the HnP target volume can be expected to perform as a gas condensate with $S_o<S_{org}$ during the production periods. Examples of the gas-condensate like behavior, along with detailed explanations, can be found in Mydland et al. (2020b). Others have suggested that the recovery is driven by (a) swelling of the oil phase to such an extent that the oil seeps out of the matrix and into the fractures[1] (Alharthy et al. 2018), (b) oil viscosity reduction due to dissolution of injection gas into the oil, and (c) a secondary solution-gas drive obtained by highly increasing the solution GOR of the oil phase (Hoffman 2019). While all these mechanisms may be present, it is likely that their effects will diminish rapidly as the fluid system in the HnP target volume transitions from being a low-GOR oil ($S_o>S_{org}$ in the matrix), to a high-GOR gas condensate ($S_o<S_{org}$ in the matrix); a mere consequence of the gas HnP process.

Gas Huff-n-Puff PVT Experiment

As mentioned, the HnP process is characterized by cyclically performing an *injection/huff period* (with an associated pressure *buildup* to some maximum pressure, p_{max}), and a *production/puff period* (with an associated pressure *depletion* back down to some minimum pressure, p_{min}). Therefore, we suggest that a HnP-relevant PVT experiment is a hybrid of the CVI (huff) and CVD (puff) experiments, with repeated

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[1] For lower-GOR oils, the oil saturation in the HnP target volume may remain large after the initial depletion period, meaning the oil saturation is significantly larger than the residual oil saturation to gas ($S_o>S_{org}$). In such case, the oil may be swollen by the injection gas to such an extent that the oil seeps out of the matrix and into fractures, adding to the oil recovery. The injectant would have to be rich (e.g. CO2, or be rich in C2 and/or C3) for the swelling to have such an impact. An example of swelling by CO2 can be seen in Figs. 8.42 and 8.43 of Whitson and Brulé (2000).

estimation of the saturation pressure at the end of each CVI by a partial constant composition expansion (CCE) experiment (see the Appendix for details of these traditional PVT experiments).

To maintain a high relevance of the experiment in the planning of a HnP field implementation (i.e. obtaining relevant information from the experiment that can be used directly in the decision-making process), one should aim to set the experiment conditions and parameters in close resemblance to those in the field. By this, we mean:

- Picking a representative in-situ reservoir fluid composition (z_i) for the well/pad/area of study, either obtained by sampling, or by estimation as outlined in Carlsen (2019b).
- Setting the injection-gas composition similar to the designated injection gas in the field, (e.g., the composition of a separator gas, CO_2, or some make-up gas that consist of components like methane, ethane, and propane).
- Selecting the reservoir temperature as the temperature for the experiment.
- Fixing the pressure cycling interval between a low pressure, set by e.g. the flowing bottomhole pressure at time of HnP implementation, and a high pressure, set by e.g. a local fracture gradient multiplied by some safety factor.

The new proposed experiment consists of the following steps:

1) Initialize the PVT cell by filling it with the selected initial fluid. Heat the cell to the reservoir temperature and perform a CVD experiment that starts at the initial reservoir pressure (p_{Ri}) and ends at the selected minimum pressure (p_{min}) for the HnP part of the experiment. This represents the initial pressure depletion prior to HnP.
2) The depleted mixture in the PVT cell is then subjected to the CVI experiment. The selected injection gas is used to do an *isochoric pressurization* of the PVT cell to the predetermined maximum pressure (p_{max}). This represents the injection (huff) period.
3) After the gas-enriched mixture has achieved equilibrium at p_{max}, a subsequent CVD experiment is performed. The PVT cell is then subjected to an *isochoric depressurization* back to p_{min} by removing fluid[2] from the top of the cell. This represents the production (puff) period. The following pressure stepping is suggested for the CVD part:
    a. If $p_{max} > p_{sat}^*$: Do a 2-stage CVD, where first stage removal is at $p_1 = p_{sat}^*$, and the second is at $p_2 = p_{min}$.
    b. If $p_{max} \leq p_{sat}^*$: Do a 2-stage CVD, where the first stage removal is at the average of p_{max} and p_{min} [$p_1 = (p_{max} + p_{min})/2$], and the second is at $p_2 = p_{min}$.
4) Steps 2) and 3) are then repeated several times (HnP cycles).

The gas HnP PVT experiment is carried out in tandem with a partial CCE experiment at the end of each CVI (huff) to quantify the mixture's saturation pressure (p_{sat}).

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[2] At pressures above the MMP_{FC}, the PVT cell is occupied with single-phase oil or gas.

A traditional CVD experiment is generally performed with more than two pressure steps. The reason we suggest two steps here, is to limit the lab time and thus reduce the experiment cost. We further suggest that 3-6 HnP cycles should be performed in the lab.

The Injection Period

The CVI experiment starts with a depleted reservoir fluid at the selected minimum pressure and reservoir temperature. The cell volume (V_{cell}) will be recorded and set as the *predetermined constant volume* to be used in the experiment. Gas is then slowly injected into the cell, bringing the pressure up to the selected maximum pressure. The mixture is then homogenized and equilibrated at p_{max} until stabilized. A partial CCE is conducted, meaning an isothermal depressurization is done for a specified number of pressure steps, down to and slightly past the saturation pressure. The saturation pressure is determined visually. The mixture is then brought back to p_{max}, where it again is homogenized and equilibrated until stabilized.

A figure schematic of the PVT cell during the injection period can be seen in **Figs. 1a-b and 2a-b**, where 1a and 1b show the case for an oil system and a gas condensate system, respectively, in which the *maximum pressure is greater than the saturation pressure* of the final mixture after injection. Figs. 2a and 2b show the case of an oil system a gas condensate system, respectively, for which *the maximum pressure is less than the saturation pressure* of the final mixture after injection.

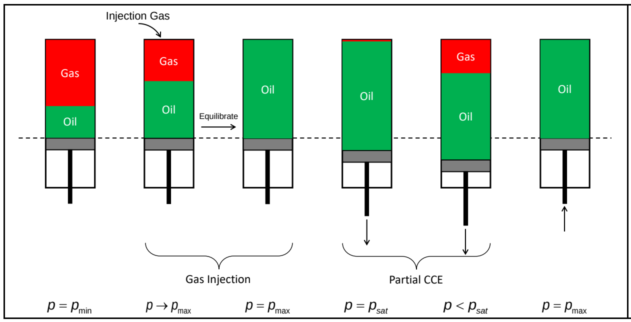

Fig. 1a—CVI for the case of $p_{max} > p_{sat}^*$ for an oil system.

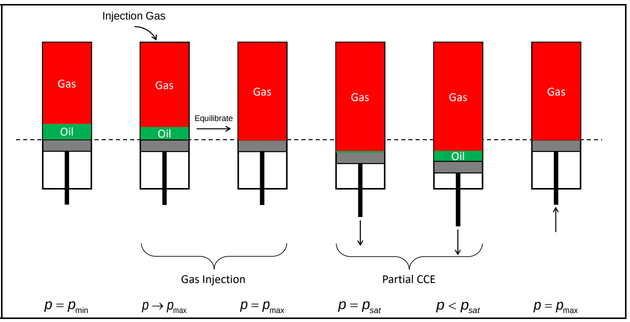

Fig. 1b—CVI for the case of $p_{max} > p_{sat}^*$ for a gas condensate system.

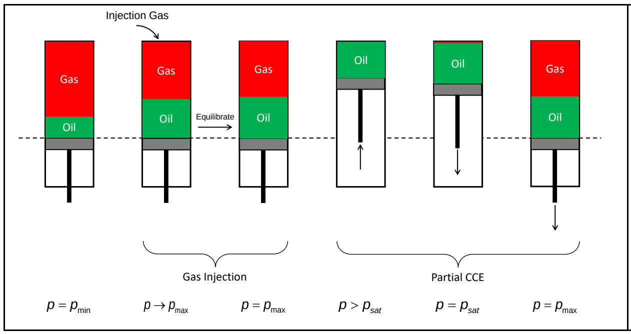

Fig. 2a—CVI for the case of $p_{max} < p_{sat}^*$ for an oil system.

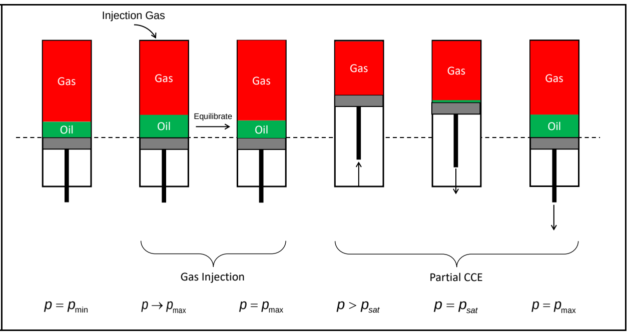

Fig. 2b—CVI for the case of $p_{max} < p_{sat}^*$ for a gas condensate system.

The Production Period

Following the injection period, is the production period where the mixture is subjected to a 2-stage CVD experiment. As mentioned, if the fluid is a single phase ($p_{max} > p_{sat}^*$) at the start of the CVD, then the first pressure step is from p_{max} to p_{sat}^*. If the fluid is two-phase at the start of the CVD, then the first pressure step is from p_{max} to $(p_{max} + p_{min})/2$. In both cases, the desired middle pressure is obtained by retracting the piston and expanding the fluid. Once the pressure is reached, the mixture is brought to equilibrium, and the total cell volume and liquid volume are measured. A portion of the mixture is displaced out of the PVT cell until the cell volume is equal to the predetermined constant volume. Transferred gas from the cell flow through a heated line through a chilled gas separator to collect any liquid deposited from the gas phase. The displaced fluid volume is measured at atmospheric conditions and is analyzed by gas chromatography. Any condensate liquid trapped is also measured and analyzed.

The second pressure step is in both cases down to p_{min}, in which the same procedure as for the middle step are performed. Once the volume is brought back to the predetermined constant volume, the system is ready to undergo a new HnP cycle.

A figure schematic of the PVT cell during the production period can be seen in **Figs. 3a-b and 4a-b**, where 3a and 3b show the case for an oil system and a gas condensate system, respectively, in which the *maximum pressure is greater than the saturation pressure* of the final mixture after injection. Figs. 4a and 4b show the case of an oil system and a gas condensate system, respectively, for which *the maximum pressure is less than the saturation pressure* of the final mixture after injection.

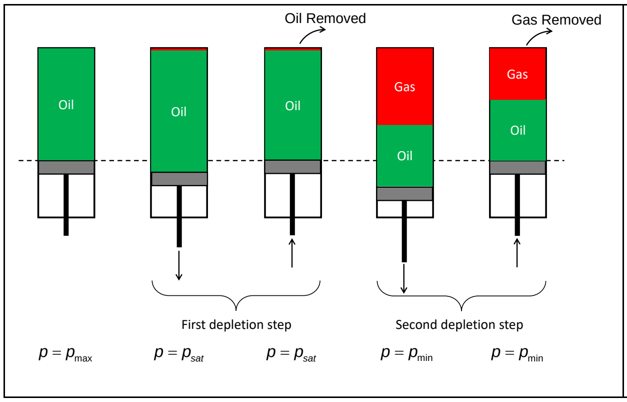

Fig. 3a—CVD for the case of $p_{max} > p_{sat}$ for an oil system.

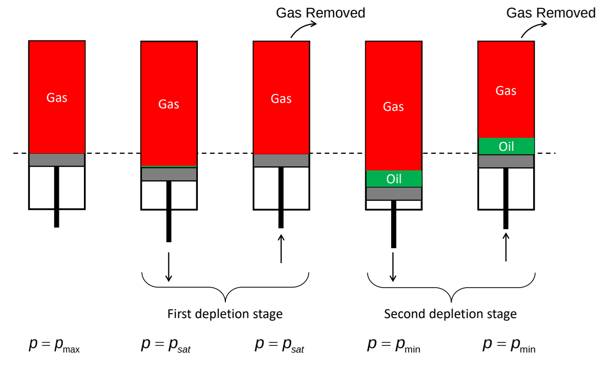

Fig. 3b— CVD for the case of $p_{max} > p_{sat}$ for a gas condensate system.

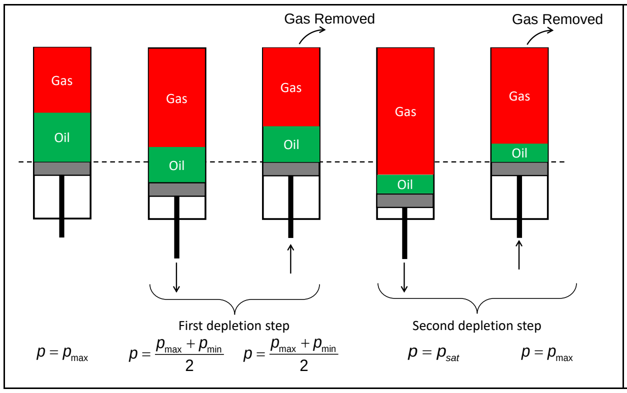

Fig. 4a— CVD for the case of $p_{max} < p_{sat}$ for an oil system.

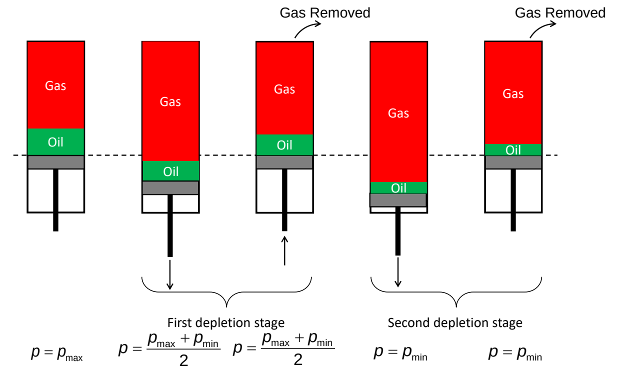

Fig. 4b— CVD for the case of $p_{max} < p_{sat}$ for a gas condensate system.

Material balance checks and *K*-values

The fluid properties of the mixture in the PVT cell will vary widely with cycle. For a fluid system that is initially deemed an oil system (e.g. a 1000scf/STB oil), a transition will (with enough cycles) occur towards becoming a gas system (i.e. reach a high cell OGR). Because the fluid phase behavior is complex, there is need for rigorous quality checks (QC) to ensure consistent measurements.

Two types of QCs are typically performed on this type of experimental data. A forward material balance (Whitson and Torp 1983) and a backward material balance (Whitson and Brulé 2000). For the gas HnP experiment, the forward material balance starts with an initial composition and moles in the PVT cell. The injected and removed moles (which can be a liquid or vapor phase) are kept track of at each stage, together with phase volumes and gas *Z*-factors, to calculate oil properties and compositions at each stage.

The equilibrium oil composition at the depletion stage of the last cycle, should be compared with the calculated final oil composition. For the depletion stages that are two-phase (below the saturation pressure), the *K*-values are calculated from reported equilibrium-gas and calculated equilibrium-oil compositions and can be plotted for consistency using $K_i(p)$ to ensure that the *K*-values do not cross[3].

The forward material balance is usually accurate for richer gas condensates and volatile oils, but less so for leaner gas condensates (Whitson and Brulé, 2000). The oil-property calculations are very sensitive to reported relative oil volumes (V_{ro}) at each stage. There is generally a higher uncertainty for smaller V_{ro} values, which in turn can exacerbate the inaccuracy of calculated oil compositions and properties for leaner gases.

The backward material balance for a CVD test provides a valuable QC for the produced C_{6+} in the removed gases. It is important to quantify this C_{6+} correctly in the HnP experiment, as it represents the incremental oil components produced. The backward material balance uses the final oil composition, final oil volume and its properties, together with produced gas moles and composition at each stage. This allows calculation of the initial fluid composition, which can then be compared to the lab reported initial composition.

Interpretation of Laboratory Results

Gas HnP EOR Efficiency

The laboratory results can be used directly to calculate the EOR efficiency of the HnP process. This efficiency is defined as incremental STB produced per MMscf injected (i.e. STB/MMscf). The inverse is known as the gas EOR utilization factor, measured in Mscf of gas injected per incremental STB produced (i.e. Mscf/STB). The former mentioned is the KPI for this experiment, as it quantifies uplift per cost; a number easily communicated to all stakeholders.

The cumulative volume of gas injected each *"huff period"* is calculated by,

$$G_{inj,l} = v_g n_{g,inj,l} \tag{1}$$

where v_g is the gas molar volume at standard conditions (379.4 scf/lbm mol | 23.69 Sm^3/kmol) and $n_{g,inj,l}$ are the moles injected in cycle l. To quantify the *"incremental oil produced*", one can assume a simplified surface process, in which C_{6-} components translate into surface gas and C_{6+} components translate into surface oil. This gives the following expression:

$$N_{p,l} = \frac{m_{C_{6+},l}}{\rho_{C_{6+}}} = \frac{n_{p,l} z_{p,C_{6+}} M_{C_{6+}}}{\rho_{C_{6+}}} \tag{2}$$

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[3] Crossing K-values would suggest that neighboring components change their relative preference to partition into the gas and oil phases as a function of pressure. Non-monotonic *K*-value behavior can be seen for individual isomers in a single carbon number fraction.

where $n_{p,l}$ are the produced moles from cycle l, m_{C6+} is the mass-, ρ_{C6+} is the mass density-, M_{C6+} is the molecular weight-, and $z_{p,C6+}$ is the mole fraction[4] of all the produced components from normal hexane (n-C_6) and heavier. The cumulative EOR efficiency after L cycles is then calculated by:

$$E_{HnP} = \frac{N_p}{G_{inj}} = \frac{\sum_{l=1}^{L} N_{p,l}}{\sum_{l=1}^{L} G_{inj,l}} \tag{3}$$

Recovery Factor

Recovery factor of surface oil, RF_o, can be calculated in a similar fashion. Original oil in place (N) is calculated by:

$$N = \frac{n_i z_{i,C_{6+}} M_{C_{6+}}}{\rho_{C_{6+}}} \tag{4}$$

in which n_i are the initial moles in the PVT cell, m_{C6+} is the mass-, ρ_{C6+} is the mass density-, M_{C6+} is the molecular weight-, and z_{C6+} is the mole fraction of all the initial components from n-C_6 and heavier. The recovery factor after L cycles is then calculated by:

$$RF_o = \sum_{l=1}^{L} \frac{N_{p,l}}{N} \tag{5}$$

Saturation Pressure

The saturation pressure of the injection gas and reservoir fluid mixture (p_{sat}^*) at end of the injection period will be different in each cycle. It is important to emphasize that this saturation pressure is not equal to the saturation pressure of the in-situ reservoir fluid. The saturation pressure type (dewpoint or bubblepoint) may also be different. How the saturation pressure changes with cycle, compared to the pressure cycling interval (i.e. p_{sat}^* versus p_{cell}), will be closely related to the EOR efficiency. The larger the difference between the maximum injection pressure and the saturation pressure, the higher the EOR efficiency, and vice versa.

Relative uplift from mixing

In this experiment, there are only two ways to recover incremental oil, either (1) by pure mixing when $p_{cell} > p_{sat}^*$ (single-phase), or (2) by vaporization when $p_{cell} < p_{sat}^*$ (two-phase). Hence, the recovery from each pressure stage during the "puff" (CVD) part of the experiment is easily categorized as either mixing or vaporization driven. If *all* the CVD pressure stages are greater than p_{sat}^* (i.e. $p_{min} > p_{sat}^*$), the relative uplift from mixing is a 100%. If *all* the CVD pressure stages are less than p_{sat}^* (i.e. $p_{min} < p_{sat}^*$), the relative uplift from mixing is a 0%. If some of the CVD pressure stages are above p_{sat}^* and the rest are below p_{sat}^*, the relative uplift from mixing is between 0% and 100%. A high "relative uplift from mixing", corresponds with a high recovery efficiency, and vice versa. For a "typical" set of reservoir oil, injection gas, and pressure cycling interval, one commonly observes a high relative uplift from mixing the first few cycles, before it drops off. The relative uplift from mixing for each cycle l is calculated by:

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[4] This is the average composition of what is being removed.

$$R_{mix,l} = \frac{N_{p,mix,l}}{N_{p,l}} \tag{6}$$

where $N_{p,l}$ is the cumulative surface oil produced during cycle l, and $N_{p,mix,l}$ is the cumulative surface oil produced by the mixing mechanism cycle l. The latter is calculated by:

$$N_{p,mix,l} = \begin{cases} \sum_{i=1}^{N} \Delta N_{p,mix,i}, & p_{cell,i} \geq p_{sat}^{*} \\ 0 & , \quad p_{cell,i} < p_{sat}^{*} \end{cases} \tag{7}$$

where $\Delta N_{p,mix,i}$ is surface oil produced at CVD stage i, and the $p_{cell,i}$ is the pressure at CVD stage i.

Use of Results with EOS Model

Performing several cycles of the HnP PVT experiment in the lab is time consuming and impractical. Hence, if one wishes to do more than the recommended 3-6 cycles, we suggest simulating the experiment. All the important information obtained in the lab (i.e. EOR recovery efficiency and saturation pressure versus cycle), including additional information not practical to estimate in the lab (e.g. MMP_{FC} versus cycle), can be calculated using a tuned equation of state (EOS) model.

The procedure of EOS model development and EOS lumping are discussed in detail elsewhere (Alavian et al. 2014, Younus et al. 2019). However, it is important to note that the data obtained from performing the experiment in the lab should be given a large weight in the tuning process of the EOS model. This will make the EOS more predictive of the HnP-related phase behavior (particularly the near-critical phase behavior which is seldomly predicted well by an untuned EOS).

Example Results of the Gas HnP PVT Experiment

In this section, two simulated examples of the gas HnP PVT experiment will be provided, one for a black oil system, and another for a gas condensate system. The compositions, and other relevant properties of the two fluid systems, are provided in **Table 1**.

The two cases will be subject to the same reservoir temperature and injection gas composition. One EOS will be used for both fluid systems for consistency[5]. The reservoir temperature is 200 °F, and the injection gas is made up by 65% methane (C_1), 20% ethane (C_2), and 15% propane (C_3). This is considered to be a relatively rich injection gas.

The reservoir-oil composition in Table 1 is described in *p-T* space by the phase envelope presented in **Fig 5**, where we see that the oil is highly undersaturated at the initial conditions (p_{Ri} = 8000 psia, T_R = 200 °F). The MMP_{FC} is approximately 6200 psia, as can be seen by the swell test provided in **Fig. 6**.

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[5] The equation of state model used is based upon more than 100 PVT reports from the Permian basin. However, the overall trends, concepts, and key takeaways are the same, irrespective of EOS model.

Component	Black Oil	Gas Condensate
N2	0.6	0.8
CO2	0.1	0.1
C1	43.1	66
C2	9	10.9
C3	6.8	5.8
i-C4	1	1
n-C4	3.5	2.4
i-C5	1.2	0.8
n-C5	1.9	1
C6	2.4	1.2
C7+	30.1	10.1
GOR, scf/STB	1000	5000
OGR, STB/MMscf	1000	200
FVF_{tot}, RB/STB	1.45	3.41
p_{sat}, psia	2985	5167
γ_{API}	43	48
GOR and OGR are obtained by a two-stage separation process, where the first stage has p = 100 psia, T = 100 °F, and the second stage is at standard conditions		

Table 1—Fluid compositions for the two fluids used in the simulated HnP PVT experiment

The results from the HnP PVT experiment provided in **Fig. 7** are generated for 10 HnP cycles. Note that the pressure cycling interval is from p_{min} = 1000 psia to p_{max} = 8000 psia (=initial reservoir pressure). Ten depletion stages during the "puff" period (CVD part) are evenly spaced out between p_{min} and p_{max}[6]. This means that the fluid will be single-phase at the first few pressure stages (pure mixing ⇔ high recovery efficiency), and two-phases for the rest of the pressure stages (vaporization ⇔ low recovery efficiency). This is thought to be representative for most field cases, where it is generally observed injection pressures greater than p_{sat}^* during the injection period, and flowing bottomhole pressure less than p_{sat}^* during the production periods. Furthermore, this example communicates many key concepts related to the gas HnP process:

- The gas EOR efficiency decreases with cycle. With enough cycles, the composition of the fluid in the PVT cell (or pore space in the field) will converge towards the composition of the injection gas. There is less additional oil to recover each cycle, resulting in the incremental recovery per volume of injected gas to decline. One should expect the same decline in EOR efficiency in the field, and that is why some operators decide to move their compressor around between several wells or pads undergoing HnP.
- The relative uplift from mixing decreases with decreasing EOR efficiency, which puts further emphasis on the importance of pure, single-phase mixing on recovery. As observed, this behavior is also closely related to the saturation pressure, p_{sat}^*, and its magnitude relative to the pressure cycling interval.
- The saturation pressure increases with cycle, which is expected for a system that is initially an oil.
- Reporting recovery factor in an isolated manner has little, to no value, in the context of gas HnP EOR.

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[6] The pressure stages are: 1000, 1778, 2556, 3333, 4111, 4889, 5667, 6444, 7222, 8000.

- The reservoir fluid (in the PVT cell, or pore space) can change phase type, as observed between cycle 5 and 6. In this example, it is caused by the injection gas amount being large, combined with a large volume of the heavier components being recovered to the “surface”. This has no practical significance but speaks to the fluid complexity exhibited by the process.

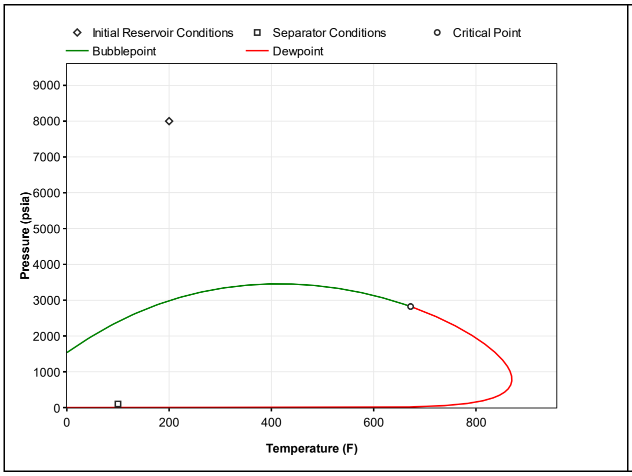

Fig. 5—The phase envelope for the reservoir oil given in Table 1.

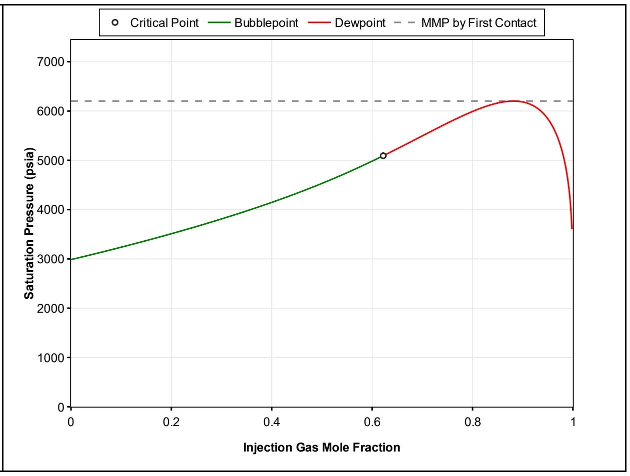

Fig. 6—The swell test for the reservoir oil given in Table 1, and an injection gas consisting of 65% C_1, 20% C_2, and 15% C_3.

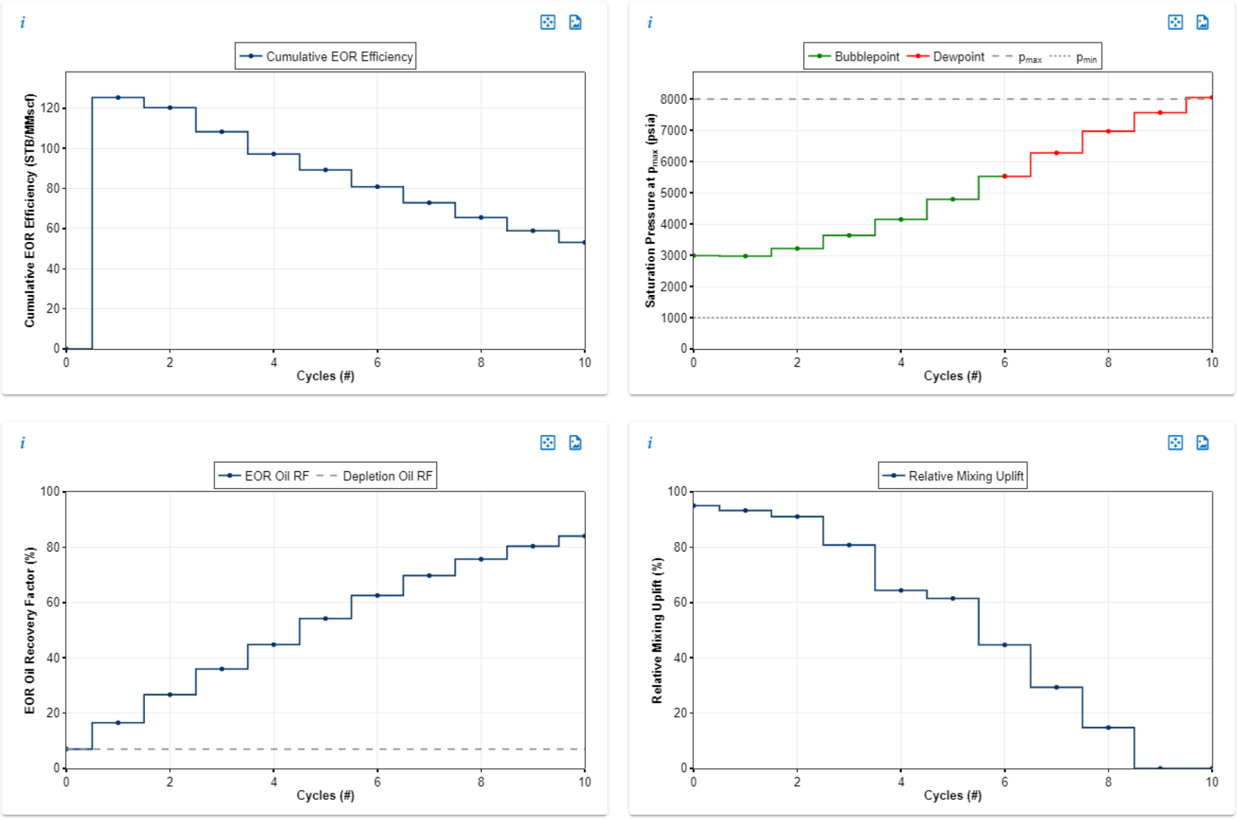

Fig. 7—(a) Cumulative EOR efficiency vs. cycle, (b) saturation pressure vs. cycle, (c) recovery factor vs. cycle, (d) relative uplift from mixing vs. cycle. The fluid system is the oil in Table 1, and an injection gas constisting consisting of 65% C_1, 20% C_2, and 15% C_3

Pressure Cycling at $p < p_{sat}^*$ for a Black Oil .

To underscore the importance of single-phase mixing, the pressure cycling interval is reduced to be between 1000 psia and 2000 psia, such that all the pressure stages are at two-phase conditions, and the corresponding recovery is solely based on vaporization. For the reservoir oil provided in Table 1, the resulting recovery efficiency is reduced to ~26 STB/MMscf, and remains fairly constant, as seen in **Fig. 8**. This is a mere one fifth of the maximum efficiency for the case in Fig. 7.

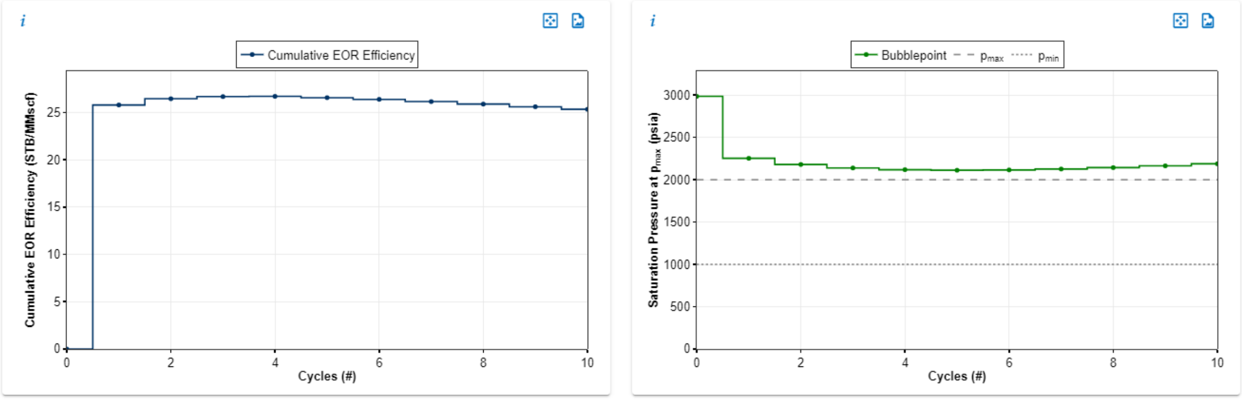

Fig. 8—Pressure cycling interval is below the saturation pressure ($p_{min} < p_{max} < p_{sat}^*$). Relative uplift from mixing is 0%. The fluid system is the oil in Table 1, and an injection gas constisting consisting of 65% C_1, 20% C_2, and 15% C_3

Pressure Cycling at $p > MMP_{FC} \geq p_{sat}^*$ for a Black Oil

To further point out the importance of mixing, the pressure cycling interval is increased to be between 7000 psia and 8000 psia, such that all pressure stages are greater than the MMP_{FC}. The corresponding recovery is then solely based on single-phase mixing. For the reservoir oil provided in Table 1, the resulting recovery efficiency is increased to 350-330 STB/MMscf, and remains fairly constant, as seen in **Fig. 9**. This is a near-threefold increase in efficiency compared to the maximum efficiency in Fig. 7.

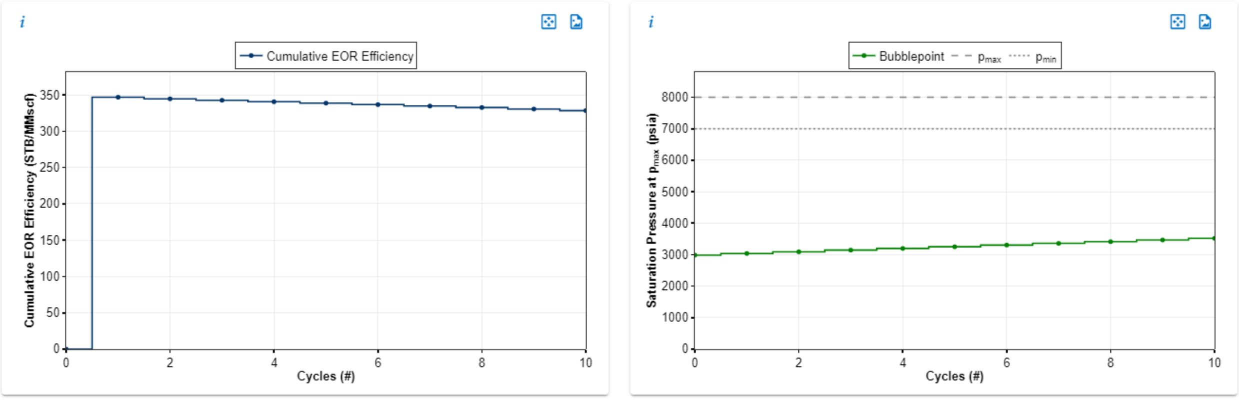

Fig. 9—Pressure cycling interval is above the first-contact minimum miscibility pressure ($p_{sat}^* \leq MMP_{FC} < p_{min} < p_{max}$). Relative uplift from mixing is 100 %. The fluid system is the oil in Table 1, and an injection gas constisting consisting of 65% C_1, 20% C_2, and 15% C_3.

Pressure Cycling at $p > \mathrm{MMP}_{FC} \geq p_{sat}^*$ for a Gas Condensate

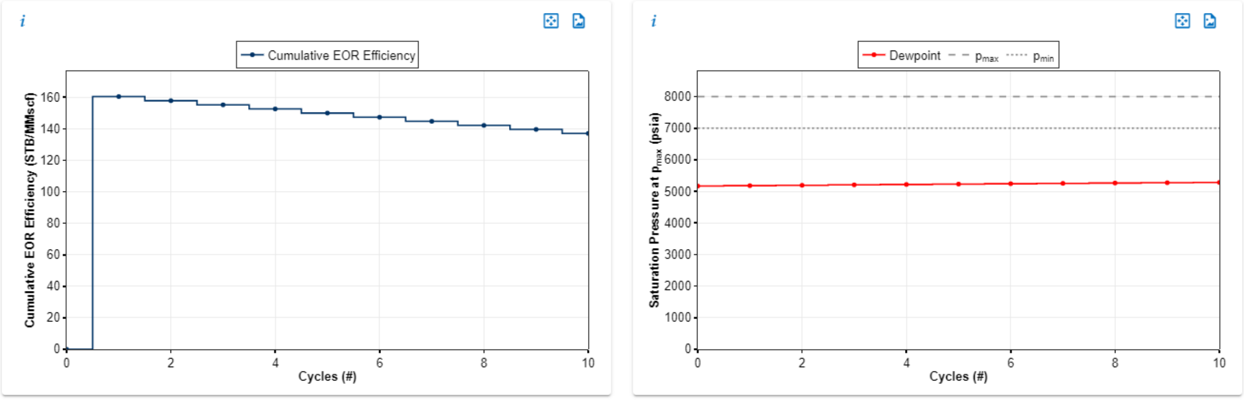

Fig. 10—Pressure cycling interval is above the first-contact minimum miscibility pressure ($p_{sat}^* \leq \mathrm{MMP}_{FC} < p_{min} < p_{max}$). Relative uplift from mixing is 100 %. The fluid system is the gas condensate in Table 1, and an injection gas constisting consisting of 65% C_1, 20% C_2, and 15% C_3.

Another interesting comparison can be made by simulating the gas HnP experiment at pressures greater than the MMP_{FC} for the near-critical gas condensate system given in Table 1. On a first order basis, one can see from the formation volume factor[7] that the target per unit pore volume is much less for the gas condensate compared to that of the oil. The FVF for the oil is 1.45 RB/STB, while for the gas condensate it is 3.41 RB/STB, corresponding to a 58% less target per unit pore volume for the gas condensate. This is also reflected by the lower cumulative EOR efficiency of 160-140 STB/MMscf shown in **Fig. 10**, which corresponds roughly to a 55% lower recovery efficiency compared to the oil case in Fig. 9.

Conclusions

The proposed gas HnP PVT experiment

1. captures the key characteristics of the gas HnP process, which are i) injection periods with associated pressure build up, ii) production periods with associated pressure drawdown, iii) a cyclic nature, and iv) a way of quantifying oil recovery versus number of cycles and/or volume (moles) of gas injected with high degree of accuracy in the overall material balance.
2. provide all relevant stakeholders with the key performance indicator (KPI) that we refer to as the gas HnP recovery efficiency (E_{HnP}), defined as *"incremental volume of stock-tank oil (STO) produced per volume of surface gas injected"* (which in field terms is denoted incremental STB of oil produced per MMscf injected). This is a practical way of communicating "*incremental uplift per cost"*.
3. can either i) be used directly to calculate gas HnP recovery efficiency, recovery factors, and relative uplift from mixing, or ii) be used as input to EOS model development.

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[7] The total formation volume factor, B_t, is used to calculate an equivalent formation volume factor (FVF) for both gas and oil systems. For an undersaturated oil reservoir ($S_g = 0$), B_t is simply equal B_o. For an undersaturated gas reservoir ($S_o = 0$), B_t is equal B_{gd}/r_s. For a two-phase saturated fluid system, the B_t is equal to a saturation weighted harmonic average of the oil and gas FVFs, i.e. $(S_o + S_g)/(S_o/B_o + S_g/(B_{gd}/r_s))$.

Nomenclature

B_{gd} = Dry gas formation volume factor

B_o = Oil formation volume factor

B_t = Total oil formation volume factor

E_{HnP} = Gas HnP recovery efficiency

G_{inj} = Cumulative gas injected

K_i = Vapor-liquid equilibrium ratio

m = Mass

M = Molecular Weight

$n_{g,inj}$ = Moles of gas injected

N_p = Cumulative oil produced

p_{cell} = PVT-cell pressure

p_{min} = Minimum pressure during the gas HnP PVT experiment

p_{max} = Maximum pressure during the gas HnP PVT experiment

p_{Ri} = Initial reservoir pressure

p_{sat} = Saturation pressure

r_s = Solution Oil-Gas Ratio

R_{mix} = Relative uplift from mixing

S_g = Gas saturation

S_o = Oil saturation

S_{org} = Residual oil saturation to gas

T_R = Reservoir temperature

v_g = Gas molar volume

V_{cell} = PVT-cell volume

V_{ro} = Relative oil volume

z = Total composition

γ_{API} = Stock-tank liquid API

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Appendix

Constant Volume Depletion (CVI)

A known volume of reservoir fluid is charged to a high-pressure PVT cell and heated to reservoir temperature. A partial constant composition expansion (CCE) is performed to determine saturation pressure, relative volume, liquid density, and liquid shrinkage data.

A volume of injection gas is added to the fluid at a constant volume until a maximum pressure is reached. The newly created sample is subjected to a CCE experiment, and the saturation pressure, saturation pressure type (*dewpoint* or *bubblepoint*) and liquid shrinkage are re-measured. The composition of the fluid mixture is calculated from the measured reservoir fluid and gas injection compositions.

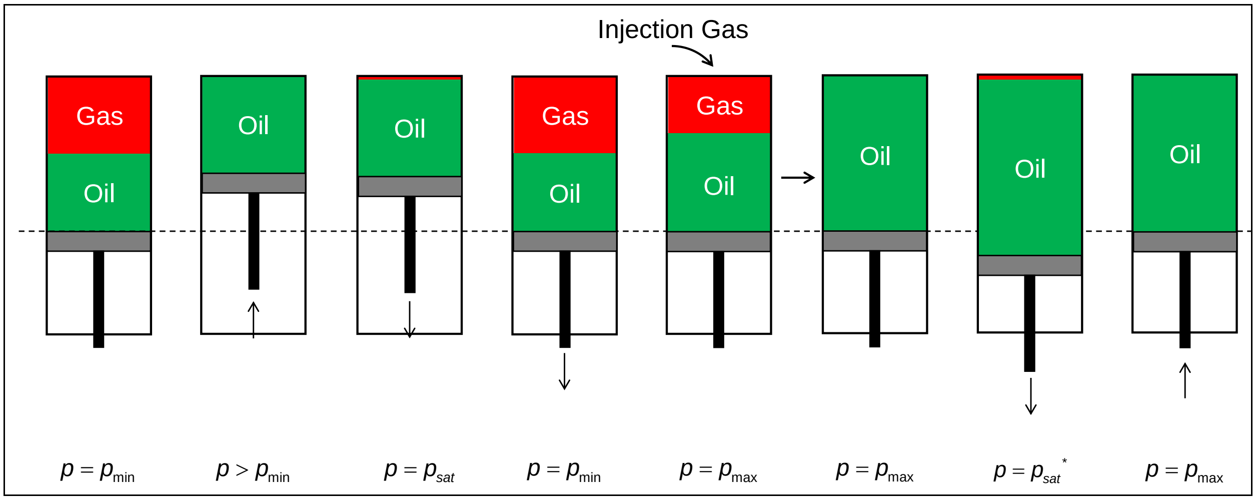

Fig. A1—Schematic representation of the constant volume injection (CVI) test

Constant Volume Depletion (CVD)

CVD experiments are typically performed on gas condensates and volatile oils to simulate reservoir depletion performance and associated compositional variation. Measured data can be used in a variety of reservoir engineering calculations, among the most useful being material-balance calculations, generating black-oil PVT properties and development of EOS models (Whitson & Torp, 1983).

A CVD experiment is conducted at reservoir temperature and begins at saturation pressure. The cell volume, V_{cell}, or the volume contained by the saturated fluid, is used as a reference volume. A second phase evolves - either solution gas (volatile oils) or retrograde liquid (gas condensates) – as the pressure is lowered and the fluid expands. Once a predetermined pressure value has been reached, excess gas[8] is removed to enforce a constant cell volume.

The withdrawn gas is analyzed using gas chromatography to determine composition, y_i. Moles of vapor produced, n_p, are calculated using the real gas law and are reported as a cumulative percent of initial moles. Compressibility factor, Z, also is calculated by noting produced vapor surface volume and equivalent cell volume (at pressure and temperature). From measured vapor gravity and composition, heptanes-plus molecular mass is back-calculated. Liquid volume is measured visually and reported as a percent of cell volume, which is actually a type of hydrocarbon liquid saturation, S_L.

The experimental procedure is repeated several times (so-called "stages") until a low pressure is reached. The remaining liquid is removed, distilled, and analyzed using gas chromatography. Measured liquid composition should check with material-balance-derived composition.

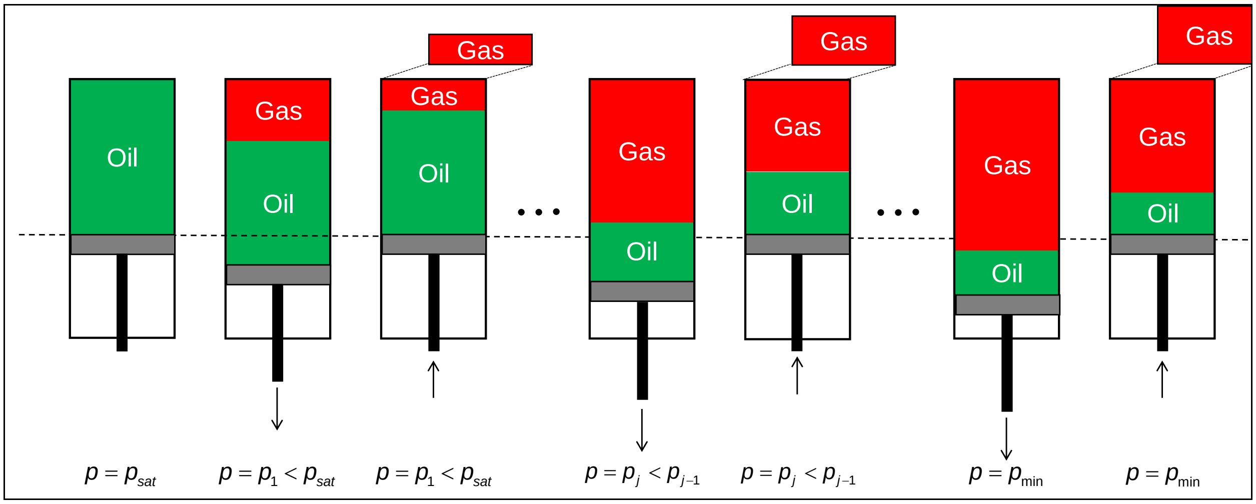

Fig. A2—Schematic representation of the constant volume depletion (CVD) test

Constant Composition Expansion (CCE)

The CCE experiment is mainly used to determine the saturation pressure of a mixture, and most CCE experiments are conducted in a visual cell. For an oil system, the undersaturated-oil density, isothermal oil compressibility, and two-phase volumetric behavior at pressures below the bubblepoint is typically reported. For a gas condensate system, total relative volume, V_{rt}, defined as the volume of gas or of gas-

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[8] The liquid phase could be removed, but not common.

plus-oil mixture divided by the dewpoint volume are provided. In addition, Z-factors at pressures greater than and equal to the dewpoint pressure and relative oil (condensate) volumes, V_{ro}, at pressures below the dewpoint are reported. V_{ro} is normally defined as the oil volume divided by the total volume of gas and oil, although some reports define it as the oil volume divided by the dewpoint volume. In the context of the gas HnP PVT experiment, the CCE experiment provides a way to quantify how the saturation pressure changes with cycles.

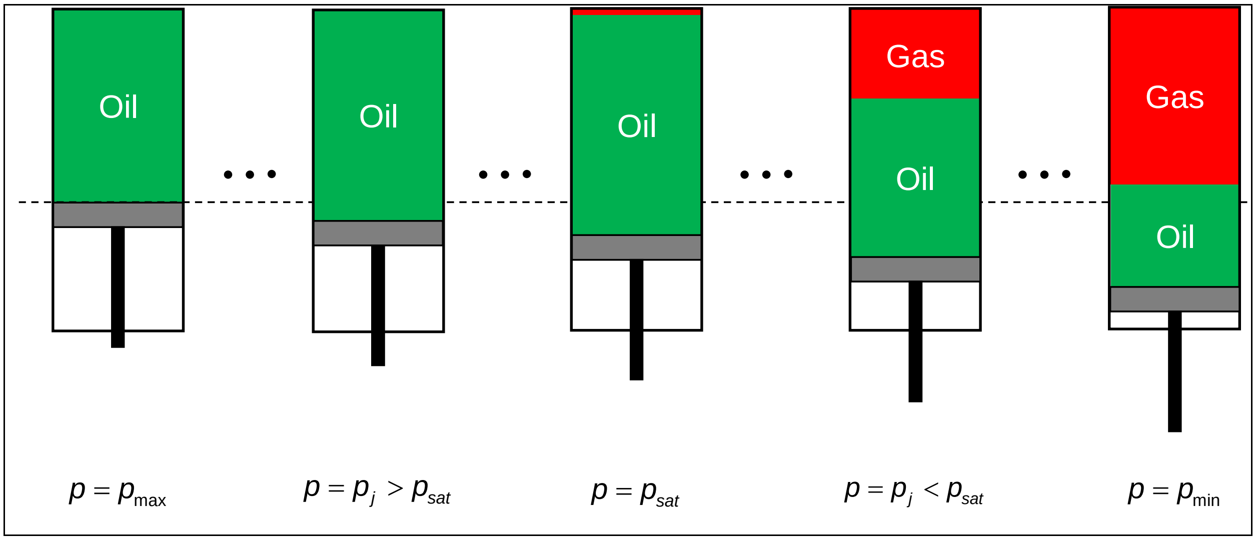

Fig. A3—Schematic representation of the constant composition expansion (CCE) experiment