Gas shales: geomechanical challenges and analysis

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ABSTRACT: Water uptake of gas shales is commonly considered one of the most important factors responsible for fluid loss during flowback operations after hydraulic fracturing. Imbibition experiments cover a key role in this context to analyze the impact of several factors that contribute to the water uptake in these unconventional reservoirs. The aim of this study is the quantification of the impact of the volumetric response (swelling and shrinkage) of gas shales on the water uptake during wetting and drying processes. An experimental methodology based on the control of total suction is developed to quantify the volumetric response in both free and under-stress conditions. Results from experiments performed through both vapour diffusion and direct flooding with deionized water on two gas shale core samples extracted from different plays are provided. Obtained results clearly highlight the mutual influence between the volumetric response and the water uptake. Specimens tested in free stress conditions exhibited a response much more pronounced than specimens tested under stress. These features provide clear evidence that the volumetric swelling of gas shales cannot be neglected for the quantification of the water uptake in imbibition tests; these aspects are expected to influence significantly the upscaling of the experimental data to estimate fluid loss at field scale.

1 INTRODUCTION

Fluid loss during hydraulic fracturing operations is one of the main challenges involved in shale gas extraction. Hydraulic stimulation is necessary to release this unconventional resource by inducing fractures in the shale gas reservoir and enhance its permeability. During the fracturing operations, thousands of cubic meters of fracturing fluids are injected in a single horizontal well at high pressure (e.g. Engelder et al., 2014). However, after the shut-in phase, typical fracturing fluid recovery during flowback operations is estimated to be around 10-20% (Makhanov et al., 2014; Engelder et al., 2014; Xu et al., 2015; Ghanbari & Dehghanpour, 2016) of the initial fluid volume injected. The low recovery of fracturing fluids may have a significant economic impact. Indeed, the fluid that remains in the reservoir may act as a barrier (water blocking mechanism), leading to a reduction of the gas (and liquid hydrocarbon) relative permeability (e.g. Bahrami et al., 2012; Paktinat et al., 2006) and gas flow.

Several aspects contribute to the low recovery of the fracturing fluid; these mechanisms mainly include the low drainage from proppant-filled hydraulic fractures (Parmar et al., 2014), the locking of fluid in secondary fractures (Fan et al., 2010), and the water uptake in the shale matrix (Roychaudhuri et al., 2013). Among these mechanisms, the water uptake in the shale matrix is believed to play a dominant role (Xu & Dehghanpour, 2014) because of the mineralogical composition and microstructure of gas shales. Indeed, clay hydration, capillarity, vapour diffusion, and osmotic flow are the principal physical mechanisms that mainly contribute to the fluid uptake in gas shales (Dehghanpour et al., 2012; Dehghanpour et al., 2013). They are related to three main factors, namely (i) the presence of negatively charged clay minerals (10-50% of the mineralogical composition) capable to adsorb water on their surface (e.g. Chenevert, 1970; Makhanov et al., 2014), (ii) the small size of the pores usually in the nanometer range (e.g. Chalmers & Bustin, 2015) which is responsible for high capillary forces and vapour condensation (Hu et al., 2001), and (iii) the different chemical potentials between the pore and fracturing fluids (e.g. Xu & Dehghanpour, 2014; Ewy, 2014).

To quantify the fluid uptake of gas shales, the concept of wettability is generally considered, which expresses the tendency of the material to be wetted by water or more generally a fluid (e.g. Dehghanpour et al., 2015; Lan et al., 2015). Different definitions and experimental methodologies are available to define the wettability. Spontaneous imbibition tests are the most common adopted technique and they are currently considered as the most efficient and reliable method to identify the wettability of gas shale (Dehghanpour et al., 2015; Roychaudhuri et al., 2013).

Typically, during imbibition tests gas shale samples are immersed in a fluid and their mass evolution over time is recorded to determine the fluid uptake.

Different aspects related to the features of gas shales make the analysis of the imbibition tests challenging and complex. These include mainly the anisotropic structure of gas shales due to presence of the lamination (or bedding planes), the mineralogical compositions and the volumetric response of gas shale during the imbibition and desiccation processes.

Despite the importance of the volumetric swelling during imbibition tests, this aspect has received poor attention (Ghanbari et al., 2015, Lyu et al., 2015). Swelling of shale and claystone is a well-known aspect for wellbore instability problem where several studies have analyzed the volumetric behavior of these geomaterials when they are in contact with the drilling fluid (e.g. Wong, 1998; Dusseault, 2011; Ferrari et al., 2014; Ewy, 2015). However, in the case of gas shales, a proper assessment and quantification of the volumetric response in both free and under-stress conditions are still missing. Makhanov et al. (2014) already posed the limitations of imbibition experiments performed at laboratory conditions and their consequences on the estimation of the fluid loss at the field scale. Indeed, the water uptake during the imbibition tests is usually analyzed without a precise assessment of the volumetric response of the tested material; this aspect usually leads to an excess of water uptake, namely an imbibed water volume higher than the initial pore space of the specimen. Moreover, free stress imbibition tests are not representative of the field conditions. Indeed, the presence of mechanical stress under in-situ conditions may be responsible for a different volumetric response of gas shale, leading to different imbibed water volume and wrong estimation of fluid loss at field scale.

Considering these factors, the main objective of the article is to analyse the impact of the volumetric response of gas shales during the wetting process on the water uptake, through a hydro-mechanical approach. To achieve this goal and improve the knowledge in this domain, a series of imbibition experiments have been performed on different gas shale samples with a methodology based on the control of total suction to simulate the wetting process.

2 MATERIAL AND METHODS

2.1 *Experimental setup and testing methodology*

Two different testing set-ups were used to investigate the gas shales response during wetting and drying processes in free stress and under stress conditions, respectively. The set-ups were developed from the work presented in Ferrari et al. (2016) and Minardi et al. (2016). In both cases, imbibition and desiccation processes were applied to the tested materials through both vapour diffusion and direct flooding with water. The vapour equilibrium technique (Romero, 2001), which foresees the control of relative humidity (RH) in a closed desiccator by using different saline solutions, was used to impose wetting and drying processes in different steps through vapour diffusion mechanism. Indeed, water exchange between the solution and the pore fluid of the material occurs through the vapour phase until an equalization condition is achieved (i.e. pore fluid and water vapour have the same chemical potential). Different salts were used for the preparation of saline solutions: $MgCl_2$, $Mg(NO_3)_2$, NaCl, KCl, KNO_3. Direct flooding of the specimens with deionized (DI) water was always performed after the equalization of the tested specimens to a high relative humidity value (92%, with KNO_3) to induce a progressive imbibition of the specimens and avoid the possibility of a slaking failure on surface of the specimens. Relative humidity can be converted to total suction according to the following psychrometric law:

$$\Psi = -\frac{RT\rho_w}{M_w}\ln(RH) \quad (1)$$

where R is the ideal gas constant, T is the absolute temperature, ρ_w is the water density, and M_w is the molecular weight of water. Total suction represents the potential of the pore water and it is the sum of matric suction and osmotic suction (Tarantino, 2010). This parameter was used to control the unsaturated conditions of the tested gas shales and perform entire the experimental analysis.

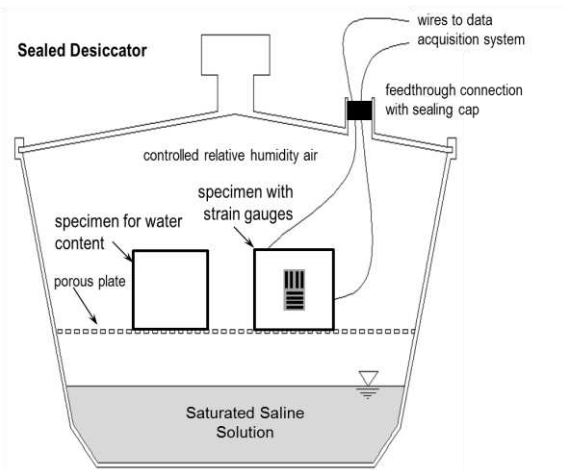

Figure 1. Testing set-up adopted to perform tests in free stress conditions (Minardi et al., 2018).

Figures 1 and 2 show an overview of the testing set-ups developed to carry out the experimental investigation. To perform tests in free stress condition a glass desiccator was used, where the saline solution is placed at the bottom (Figure 1). Two specimens were then used: one to control the evolution of the water content, and a second one equipped with two biaxial strain gauges to monitor the volumetric response during the imposition of wetting and drying processes.

To perform tests under stress, a uniaxial testing device was adopted (Figure 2). Total suction was always controlled with the vapour equilibrium technique where a container containing the solution was connected to the device with a system of tubes. A peristaltic pump was used to force the circulation of vapour from the container to the specimen, in order to apply wetting and drying processes. The tested specimens were equipped with biaxial strain gauges for the measurement of the deformations.

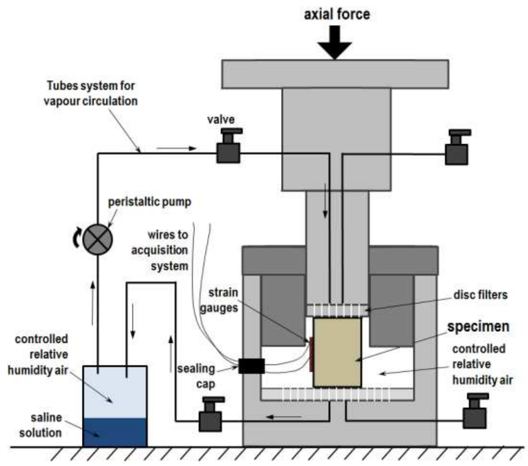

Figure 2. Testing set-up adopted to perform tests under stress conditions (Minardi et al., 2018).

Two tests were carried out in free stress conditions on two different gas shales, and two tests were performed under stress (7 MPa and 15 MPa of axial stress) on the same gas shale. Wetting/drying cycles were performed between 150 MPa, 10 MPa, and 0 MPa of total suction, with intermediate equalization steps. An initial equalization to 150 MPa was initially performed to have the same initial reference conditions. Specimens tested under stress were prepared with the bedding orientation perpendicular to the applied axial load. Further details regarding the adopted experimental set-ups and testing methodologies can be found in Minardi et al. (2018).

2.2 *Test materials*

Two gas shales core samples (identified as cores A and B) were used for the experimental investigation. The cores were retrieved from wells drilled in different unconventional shale plays at depths of about 1500 m, and 2700 m, respectively. All of the core samples exhibit a visible laminated structure. Table 1 summarizes the mineralogical composition of the materials obtained from X-ray Diffraction (XRD) analyses. ‘Other’ consists primarily of plagioclase, K-feldspar and pyrite (17% plagioclase in the case of Core B). The gas shale core A is clay rich shale, while the core B presents a more balanced mineralogical composition. With regard to the clay content, it is dominated by the illite/smectite group (I/S group) for both cores; the amount of kaolinite or chlorite is very small. In particular, for the core A illite is the dominant clay mineral, with a smectite content in the I/S group lower than 5%; on the other hand, the core B has a I/S group dominated by smectite minerals (61%).

Table 1. Mineralogical composition of the tested shales in terms of wt%.

Core	**A**	**B**
Quartz [%]	27	17
Carbonate [%]	2	26
Clay [%]	57	28
Organic [%]	7	5
Other [%]	7	24

3 RESULTS

The experimental results are presented in this section. Figure 3 shows the relationship between the water content and total suction for the two tested cores in free stress conditions. The core B experienced higher values of water content and more pronounced variations during the wetting and drying processes. This aspect has to be related to the different porosity of the materials; tested specimens have initial porosity of 5.2% and 6.5% for the core A and B, respectively. Although this difference (1.3%) is very small, its impact on the water uptake cannot be neglected due the low porosity values of these geomaterials.

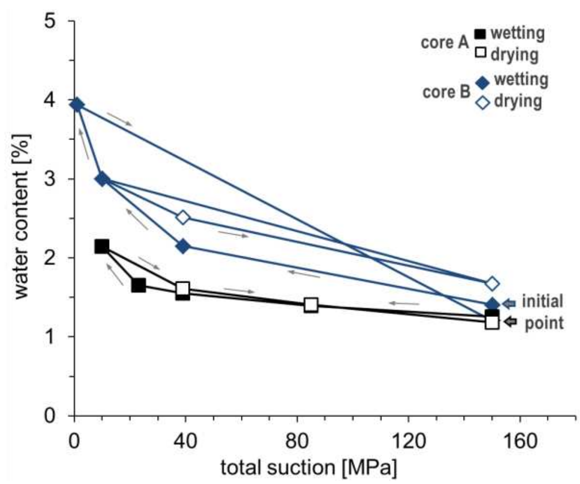

Figure 3. Evolution of the water content during the total suction variation process.

Moreover, as the materials are exposed to higher and lower values of total suction, volumetric deformation are exhibited. Figures 4 and 5 show the relationship between the volumetric deformation and total suction for the core A and B, respectively. A significant swelling is observed during the wetting phase of the test, while lower shrinkage is exhibited during the drying phase. The observed behavior is characterized by a significant irreversible deformation over a wetting/drying cycle. This feature is usually associated to a degradation of the material and it is related to the possible generation of cracks and fissures in tested specimens during the expansion. Moreover, the response exhibited is also significantly non-linear; the aspect is related to the evolution of the water content and it highlights the hydromechanical coupling of the material's response.

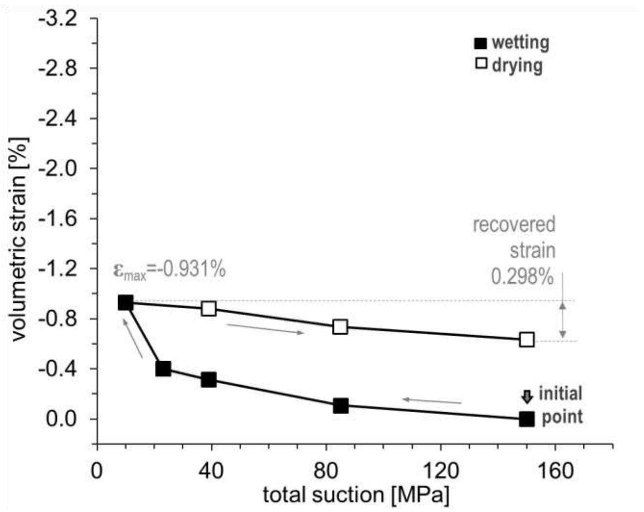

Figure 4. Evolution of the volumetric strain for the free stress test performed on the gas shale core A.

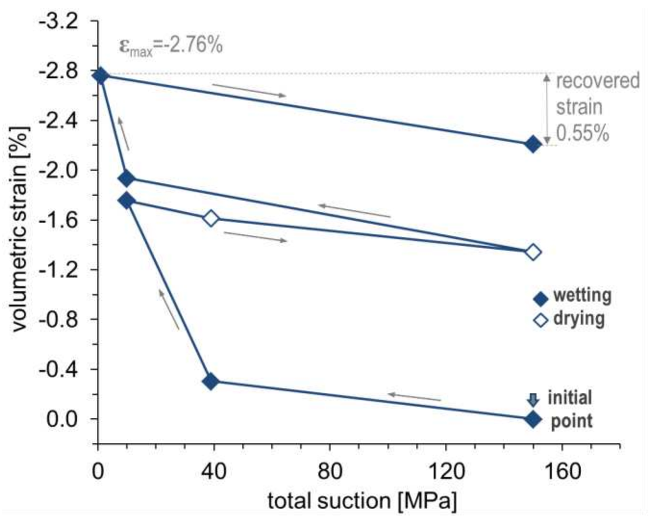

Figure 5. Evolution of the volumetric strain for the free stress test performed on the gas shale core B.

Due to the presence of bedding planes, the observed behavior is also significantly anisotropic. Figure 6 illustrates the response in the two directions (perpendicular $\varepsilon^{\perp}$ and parallel $\varepsilon^{//}$ to the bedding) for the free stress test performed on the gas shale core B. A more pronounced deformation is experienced in the direction perpendicular to the bedding, which is more than four times higher than in the parallel direction. Moreover, from the graph it is possible to observe that most of the irreversible deformation observed in the Figure 5 has to be related to the response perpendicular to the bedding. This aspect suggests that the generation fissures along the direction of the bedding is the main aspect responsible for the permanent deformation exhibited at the end of the wetting/drying cycle.

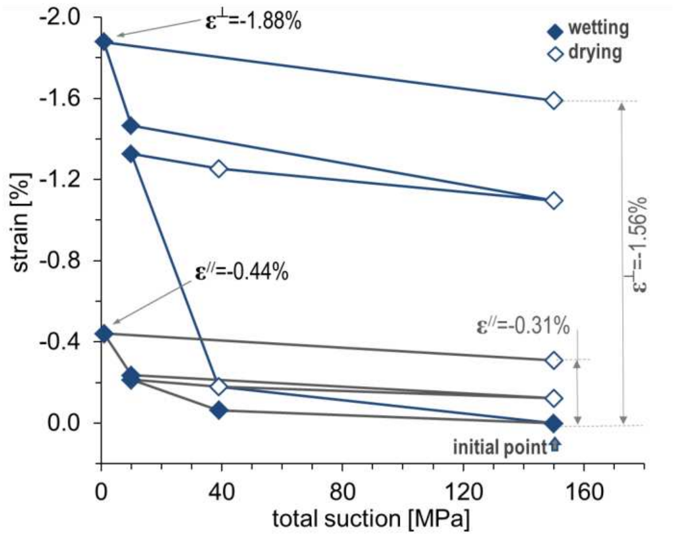

Figure 6. Response of the gas shale core B in the directions perpendicular and parallel to the bedding.

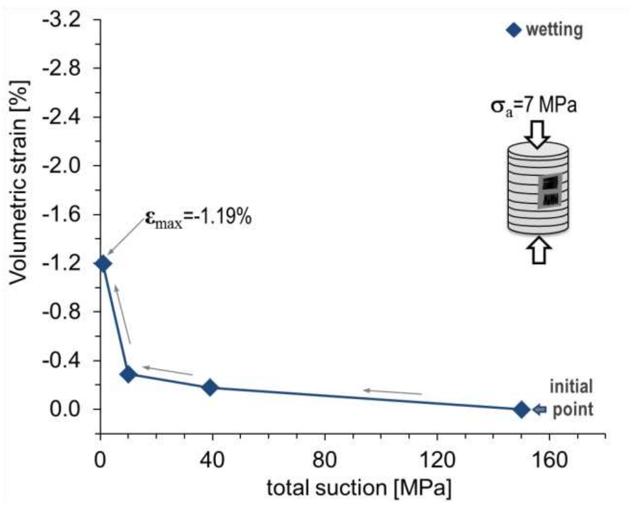

Figure 7. Volumetric response exhibited by the specimen tested at 7 MPa of axial stress (core B).

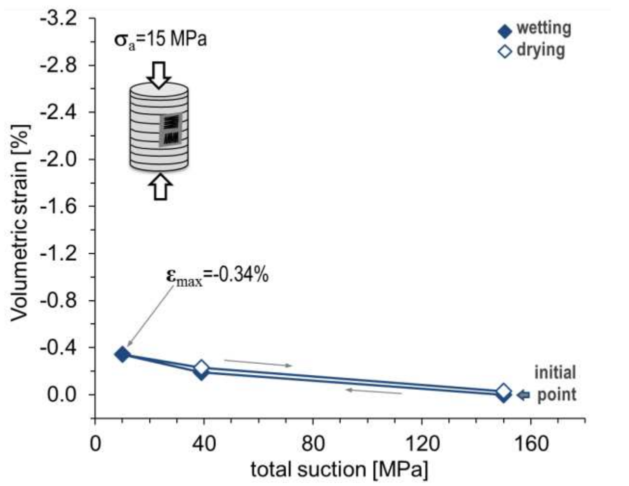

Figure 8. Volumetric response exhibited by the specimen tested at 15 MPa of axial stress.

The application of a mechanical stress affects significantly the response of the material. Figures 7 and 8 depict the volumetric behavior exhibited by the specimens (gas shale core B) tested under 7 MPa and 15 MPa of axial stress. Firstly, a significant reduction of the volumetric swelling during the wetting processes is observed. In particular, regarding the test performed at σ_a = 7 MPa (Figure 7), the final volumetric expansion is more than two times lower compared to the swelling observed in the free stress test (-1.19% against -2.76%); this difference is mainly caused by the different response observed during the equalization to 10 MPa of total suction; hence, to observe a significant increase of volumetric strain under stress, lower total suction values have to be imposed. A second aspect related to the presence of the mechanical stress is highlighted by the test carried out at 15 MPa of axial stress (Figure 8). The graph shows a significant reduction of the permanent deformation over the wetting/drying cycle with respect to the test performed in free stress conditions (Figure 5). The observed behavior is almost completely reversible, meaning that the presence of a mechanical stress is able to reduce significantly the possible generation of fissures during the wetting phase.

4 DISCUSSION

These experimental results play a fundamental role to analyze the impact of the volumetric swelling behavior of gas shale on their water uptake. In particular, a misleading evaluation of the imbibed water volume can be obtained if the volumetric expansion of the material is not properly assessed during the wetting process. The proposed experimental methodology was able to quantify this aspect, and the results of the free stress performed on the core B demonstrate that the swelling response during the wetting process is responsible for an additional 45% of water uptake by the tested gas shale. This feature can be observed in the Figure 9, where the initial pore volume of the specimen is compared to the final pore volume at the end of the equalization to 0 MPa of total suction.

Although the importance of this result, an important drawback of free stress tests is that they cannot be considered representative of the field conditions. Several factors such as in-situ stress, temperature, fluid viscosity, and in-situ water saturation should be considered in order to have more representative data. In the performed analysis we just focused on the role of the mechanical stress on the volumetric swelling. The results obtained on the core B under stress conditions (Figures 7 and 8) clearly quantify and demonstrate that the volumetric behavior of the tested gas shale induced by wetting and drying processes under stress is significantly different compared to the behavior obtained from the free stress test (Figure 5). Although the imbibed amount of water could not be directly measured during the tests performed under axial stress, it is possible to assume that the imbibition process must have been different compared to the free stress test, due to the very different volume expansion. To this regard, Figure 9 shows also the final pore volume obtained if the volumetric expansion measured under 7 MPa of axial stress is applied to the initial pore volume from the free stress test; this value of pore volume (1.23 cm^3) is lower than the final imbibed water volume (1.39 cm^3) obtained from the free stress test, meaning that when the swelling of the material is hindered by the mechanical stress, a lower imbibed amount water is expected.

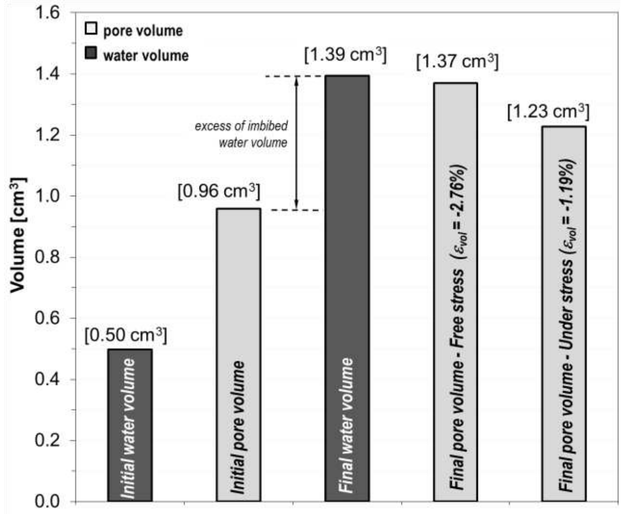

Figure 9. Initial and final pore-water volumes for the free stress test on the core B along with the final pore volume of the specimen tested at 7 MPa of axial stress (Minardi et al. 2018).

5 CONCLUSIONS

The study has shown an experimental methodology to properly quantify the volumetric response of gas shales during imbibition and desiccation processes and assess its impact on the imbibed water volume. The presented results have demonstrated that, if the volumetric response of gas shales is not properly measured during the imbibition process in free stress conditions, a misleading evaluation of the imbibed water volume can be obtained; in particular, an excess of the imbibed water volume of 45% is obtained when the swelling response is neglected. Moreover, the mechanical stress has been found to significantly affect the response of gas shales in particular during the imbibition process, where the volumetric swelling of the material can be more than two times lower compared to the response observed in free stress tests; due to this difference, the amount of imbibed water volume under stress has to be necessary lower than in free stress conditions. So, imbibition tests performed without any applied mechanical stress are expected to lead to a significant overestimation of the imbibed water volume, even if the volumetric swelling is measured. Hence, a proper evaluation of the water uptake of gas shales has to be carried out considering the imbibed water volume of the specimen coupled with its swelling response under stress. These outcomes are expected to play a key role on the upscaling of imbibition data to estimate the water loss at the field scale.

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