Natural Hydrogen Development-Potential and Challenges

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This document is a preprint of a peer-reviewed full journal paper that has since been published in **International Journal of Hydrogen Energy** under https://doi.org/10.1016/j.ijhydene.2025.05.357

It has been uploaded onto EarthArXiv to promote early access to scientific knowledge and findings, under https://doi.org/10.31223/X5VH9R

Abstract

Natural hydrogen has recently been identified as a potential source for future energy systems. This paper investigates the technical development potential of natural hydrogen by estimating, for some recent finds and identified prospects, in-place and recoverable hydrogen, well productivity, water production and other byproducts that a future development would have to cater for. Finds are in three broad play types: 1) focused-seepage plays where predominantly aqueous hydrogen migrates with minimal trapping; 2) coalbed plays where hydrogen is adsorbed molecularly in coals; 3) reservoir-trap-seal plays with gaseous hydrogen trapped underneath an impermeable seal. Focused-seepage plays have a low to modest hydrogen resource-density, low well-productivity and developments may co-produce large volumes of water. Coalbed hydrogen plays may have higher resource density but again, low well-productivity. Only developments of reservoir-trap-seal plays could potentially achieve industrial offtake but to date no accumulations of this type have unambiguously been discovered.

Keywords

Natural Hydrogen, White Hydrogen, Play Classification, Resource Assessment, Field Development, Decarbonization

1. Introduction

Global demand for hydrogen is projected to increase more than fivefold by 2050 [1]. Future supplies of hydrogen are expected from electrolysis of water using renewable electricity (green hydrogen) and from fossil fuel sources coupled with carbon capture, utilization, and storage (blue hydrogen). A more speculative supply of hydrogen could be natural hydrogen, sourced from the subsurface (also known as white or geologic hydrogen). Encounters of natural hydrogen (e.g. Mali [2] [3], Eastern France [4], Albania [5], South Australia [6] [7], the US Mid-West Ridge [8]) and many occurrences of “fairy circles” or Sub-Circular Depressions (SCDs), oval-shaped structures with anomalous vegetation attributed to escaping gases including hydrogen [9], challenge the belief that hydrogen in molecular form is rare in the shallow subsurface. Hydrogen finds to-date have been encountered by serendipity while exploring for water or hydrocarbons [10], stressing the need for dedicated exploration methodologies.

Reviews of natural hydrogen systems have mostly focused on exploratory aspects such as overall geological setting [11] [12], hydrogen-sources and generation processes [9] [13] [14] [15], hydrogen flux-rates and global hydrogen-system potential [16], and hydrogen detection [6] [17]. However, for natural hydrogen to materially contribute to industry and energy-systems decarbonization, the technical development potential of different settings and play types should also be considered. This would help identify those natural-hydrogen plays and prospects that, in case of exploration success, have the highest chance of being commercially viable.

At present, hydrogen demand is mostly from large industrial facilities like petroleum refineries and ammonia plants ([18] [19]; Fig. 1). Decarbonization efforts could create hydrogen demand from other large industrial buyers but also from smaller, local hydrogen-offtake ventures like vehicle fuelling hubs (Fig. 1). However, even the smallest commercial applications would likely require supply in excess of 1,000 ton hydrogen per year and a supply commitment for several years.

In this paper, we use the concepts of integrated prospect analysis and value assessment that are common industry-practices in the assessment and ranking of petroleum prospects [20] [21]. This approach assesses the prospective ranges of in-place and recoverable resources, well productivity, water production and other byproducts that a future development would have to cater for. A notional prospect-development plan is then crafted to yield indicative development metrics such as well counts and quantity of resource required to sustain commercial offtake. In the case of petroleum prospects, assessment of resource potential, well productivity and the like are typically based on analogue developments [20]. In the case of natural hydrogen, there are no commercial-scale developments just yet but we propose that resource-assessment methodologies and analytical techniques in use for oil and gas can be deployed with some modification to cater for the specifics of natural hydrogen.

Hydrogen phase (gaseous vs aqueous) and nature of storage (trapped in porous layers at excess pressure, adsorbed at molecular scale or merely migrating through porous and permeable rock) are key considerations that control recovery potential and well productivity and consequently, different settings require a different resource-assessment approach. In this paper we categorize the different play types from a viewpoint of recovery mechanism and exploitation potential. We illustrate this grouping into development play-types by actual field examples for which we calculated estimates of hydrogen resource-density, well productivity, water production, well count and resource area required to meet industrial-scale offtake. Especially well count and resource area are metrics that illustrate the potential and challenges for commercial development of different play-types.

Due to the high volatility and reactivity of hydrogen, the odds of finding material quantities of pure molecular hydrogen in the subsurface may be low. This paper does not intent to discuss the chances of discovering subsurface hydrogen-accumulations, the Chance Of geological Success (COSg). Instead, the purpose here is to discuss the technical development potential and challenges for the different play-types of natural-hydrogen, which may translate into the Chance of Development (CoD [22]).

2. Theory and calculation methods

This section outlines the methodologies deployed in calculating metrics that illustrate the technical development-potential of natural hydrogen. Calculations made use of an Excel plug-in library of petroleum-engineering equations, Petroleum Office™. Table 1 lists the input parameters into the resource equations 1 to 21 and corresponding standard units. Supplementary material published with this paper includes an Excel workbook with spreadsheet tables to illustrate the application of resource-assessment methodology and equations for each of the field examples discussed in Section 3 of this paper.

2.1. Hydrogen resource-density

The amount of hydrogen per unit area of a prospect or find depends on the form in which that hydrogen is found (or assumed present in case of a prospect) in the subsurface [11] [23]: 1) as gas dissolved in water, 2) as molecules adsorbed onto e.g. coal, 3) as residual gas (immobile inclusions), or 4) as free gas. To estimate resource density we have used methodologies normally deployed in oil and gas resource assessment including standard rock- and fluid-parameter correlations [26] [27] but with modifications to handle the specifics of natural hydrogen.

2.1.1. Resource density for aqueous and residual hydrogen

Where hydrogen is dominantly dissolved in formation water alongside smaller amounts of residual gas, hydrogen resource-density can be calculated as follows:

First, reservoir-porevolume-per unit area (*PV*) is computed as:

$$PV = h \times NtG \times Por \tag{1}$$

where *h* = gross reservoir thickness, *NtG* = reservoir net-over-gross ratio and *Por* = net-reservoir porosity.

Maximum hydrogen-solubility at reservoir conditions is calculated using Henry's law:

$$C_i = P_i \,/\, K_H \tag{2}$$

where C_i = initial hydrogen solubility, P_i = initial reservoir pressure and K_H = Henry's constant for hydrogen at reservoir temperature. For the sake of simplicity, we use a single value for Henry's Constant for hydrogen (1282.05 l×atm/mol at 25 °C [24]). In situations where sufficient data on temperature and salinity of the formation water is available, estimates of Henry's Constant can be refined using analytical models, e.g. [25].

Residual hydrogen gas in-place-per unit area ($H_2g_{res}IP$), at initial conditions in mass units, is calculated as:

$$H_2g_{res}IP = PV \times S_g \times H_2frac \,/\, B_{gi} \times H_2den \tag{3}$$

where S_g = total (residual) gas saturation including other gases, H_2frac = fraction of hydrogen in the gas (it is assumed here that residual and dissolved gas have the same hydrogen content), B_{gi} = gas formation-volume factor (inverse of gas expansion-factor) for hydrogen at initial reservoir conditions (estimated from industry-standard equations, i.e. using pseudo-critical temperature and pressure for hydrogen to calculate a hydrogen gas-compressibility "Z" factor [26], and H_2den = density of hydrogen at standard conditions.

Dissolved hydrogen in-place per unit area (H_2aqIP), in mass units, is then estimated as:

$$H_2aqIP = PV \times (1\text{-}S_g) \times H_2frac \times C_i \times H_2moleden \tag{4}$$

where $H_2moleden$ = molecular density of hydrogen. H_2frac is multiplied with the maximum hydrogen solubility at initial conditions (C_i) to reflect the partial pressure of hydrogen at the gas-water interface.

Finally, the total hydrogen in-place per unit area (H_2IP) is estimated by summing the aqueous and residual-gas components:

$$H_2IP = H_2aqIP + H_2g_{res}IP \tag{5}$$

The principal recovery mechanism in aqueous-hydrogen systems would be pressure depletion, achieved by lifting formation water from the wells. Pressure depletion lowers hydrogen solubility, releasing dissolved hydrogen (from water produced by the well and from the pressure sink around the well). Depletion will also cause expansion of residual gas which, in turn, increases gas saturation and, assuming initial S_g was near-critical), remobilizes some of this gas.

Recovery efficiency of aqueous systems remains speculative. The closest analogue to aqueous hydrogen exploitation may be the studies of methane-extraction potential from aquifers [28] [29]. To date, however, this has not been attempted commercially. Our method of estimating recoverable hydrogen assumes that fluid lifting in producer wells can achieve a certain amount of average pressure depletion, and that hydrogen released from solution and remobilized residual gas would make its way to the producer wells within the production time period. Assumed average pressure-depletion at the end of production should reflect the specifics of the aqueous hydrogen reservoir (thickness, porosity, permeability, pressure, connectivity), its attached aquifer size and the assumed producer-well design and completion concept.

With these assumptions, steps to quantify the recoverable hydrogen per unit area are as follows.

First, hydrogen solubility at depleted reservoir conditions is calculated as:

$$C_r = P_r / K_H \quad (6)$$

where C_r = depleted hydrogen solubility, P_r = depleted reservoir pressure. K_H = Henry's constant for hydrogen.

Residual hydrogen gas in-place-remaining-per unit area ($H_2g_{res}Rem$), at depleted reservoir conditions in mass units, is calculated as:

$$H_2g_{res}Rem = PV \times S_g \times H_2frac / B_{gr} \times H_2den \quad (7)$$

where B_{gr} = gas formation-volume factor for hydrogen at depleted reservoir conditions (estimated using industry-standard equations).

Dissolved hydrogen in-place-remaining-per unit area (H_2aqRem), at depleted reservoir conditions in mass units, is estimated as:

$$H_2aqRem = PV \times (1\text{-}S_g) \times H_2frac \times C_r \times H_2moleden \quad (8)$$

Finally, recoverable hydrogen resource density (H_2UR) is quantified as:

$$H_2UR = H_2IP - H_2aqRem - H_2g_{res}Rem \quad (9)$$

Note that this analytical approach only provides an indicative estimate of recoverable hydrogen-resource potential for a given play site; it cannot capture the details of reservoir depletion and impact of reservoir heterogeneity.

2.1.2. Resource density for adsorbed hydrogen

Where hydrogen gas is adsorbed, on a molecular scale, into the mineral fabric of adsorbent rocks like coals or organic-rich shales, steps to calculate the hydrogen resource per unit area are as follows.

Total adsorbed gas in-place-per unit area (GIP) is calculated as:

$$GIP = h \times RHO_b \times GC_{raw} \quad (10)$$

where h = net thickness of adsorbent rock, RHO_b = bulk density of adsorbent rock and CG_{raw} = raw gas content in adsorbent rock (per bulk unit of mass). If gas content data is not raw but dry and ash-free (GC_{DAF}), the formula to estimate GIP is:

$$GIP = h \times RHO_b \times (1\text{- } Ash - Moisture) \times GC_{DAF} \quad (11)$$

where *Ash* and *Moisture* content of the adsorbent rock are expressed in weight fractions.

Hydrogen gas in-place per unit area (H_2GIP), in mass units, is then calculated as:

$$H_2GIP = GIP \times H_2frac \times H_2den \tag{12}$$

where H_2frac = fraction of hydrogen in the total adsorbed gas and H_2den = density of hydrogen at standard conditions.

The principal recovery mechanism in adsorbed gas systems is pressure depletion, achieved by lifting formation brine from producer wells. Pressure depletion lowers gas adsorption-capacity and hence releases gas from the adsorbent rock, either from the onset of fluid lifting (in case of maximum adsorption capacity) or, in case of undersaturated adsorbent rock, once pressure depletion has lowered adsorption capacity to the point where it equals the actual gas content. Gas desorbs into the fracture and cleat system of the coals and from there, it flows towards and into the wells.

Since coalbed-methane (CBM) developments are a producing example of adsorbed gas systems, recovery efficiencies observed in CBM may be considered as analogues for the recovery efficiency achievable from adsorbed-hydrogen plays.

Recoverable hydrogen Resource density (H_2UR) can hence be estimated as:

$$H_2UR = H_2GIP \times RF \tag{13}$$

where RF = (analogue) Recovery Factor

2.1.3. Resource density for free-hydrogen gas

In settings where hydrogen is dominantly in gaseous form, trapped in porous reservoirs and retained by impermeable caprock, steps to calculate the free-gas hydrogen density are similar to methane calculations in the gas industry.

First, reservoir porevolume per unit area (PV) is computed as:

$$PV = h \times NtG \times Por \tag{14}$$

where h = gross reservoir thickness, NtG = reservoir net-over-gross ratio and Por = net-reservoir porosity.

Free hydrogen gas in-place-per unit area (H_2GIP), in mass units, is calculated as:

$$H_2GIP = PV \times S_g \times H_2frac \,/\, B_{gi} \times H_2den \tag{15}$$

where S_g = total (free) gas saturation including hydrogen plus other gases, H_2frac = fraction of hydrogen in the gas, B_{gi} = gas formation-volume factor for hydrogen at initial reservoir conditions, and H_2den = density of hydrogen at standard conditions.

In free hydrogen-gas systems, gascap expansion would be the dominant recovery mechanism unless there is a very strong, active aquifer connected to the hydrogen gascap. Recovery factor would largely be a function of abandonment pressure relative to initial pressure. Assuming pure depletion, hydrogen recovery potential can be estimated as follows. First, free hydrogen-gas in-place-remaining-per unit area (H_2gRem), at depleted reservoir conditions in mass units, is calculated as:

$$H_2gRem = PV \times S_g \times H_2frac \,/\, B_{gr} \times H_2den \tag{16}$$

where B_{gr} = gas formation-volume factor for hydrogen at depleted reservoir conditions.

If a very strong and active aquifer is anticipated, aquifer pressure-support may limit gascap expansion and instead, reservoir drive may mostly come from water encroachment into the gascap. In such a situation it may be appropriate to modify the equation to calculate free hydrogen-gas in-place-remaining-per unit area (H_2gRem), at depleted/watered-out reservoir conditions in mass units, to read:

$$H_2gRem = PV \times S_{grw} \times H_2frac \,/\, B_{gr} \times H_2den \tag{17}$$

where S_{grw} = gas saturation residual to water (trapped, residual gas saturation at the imbibition endpoint which, for hydrogen-brine systems, may be around 30-35%; [32]). Note that pressure depletion may be minimal in case of a strong aquifer which means that $B_{gr} \approx B_{gi}$.

Recoverable free-gas hydrogen resource density" (H_2UR) can be estimated as:

$$H_2UR = H_2GIP - H_2gRem \tag{18}$$

2.2. Well production rates

A combination of analogue data and industry-standard petroleum engineering equations (e.g. pseudo-steady-state productivity of gas and water wells) has been used to estimate indicative well productivity for the case-studies analysed. Fluid- and reservoir-parameter input into these equations have been derived based on available reservoir, pressure and temperature data for the respective case-studies combined with industry standard correlations and estimation methods.

2.3. Water production and other byproducts

Water production rates associated with a hypothetical development of field examples of the different plays, are estimated using material balance.

First, pressure depletion per unit of water extracted per unit area ($P_{depl}\_per\_VolWat_{res}$) is calculated:

$$P_{depl}\_per\_VolWat_{res} = (1 \,/\, PV) \,/\, (C + C_f) \tag{19}$$

where PV = reservoir porevolume per unit area, C = fluid compressibility and C_f = formation (rock matrix) compressibility. Compressibility values are calculated using industry-standard methods [27].

The anticipated water produced per unit area ($VolWat$) as a result of fluid lifting for hydrogen extraction, is then calculated:

$$VolWat = (P_i - P_r) \,/\, P_{depl}\_per\_VolWat_{res} \,/\, FVF_w \tag{20}$$

where P_i = initial reservoir pressure; P_r = depleted reservoir pressure; and FVF_w = formation-water volume factor (calculated using industry-standard methods [27]).

Estimates of produced water derived via this method are conservative as there is no attached aquifer beyond the resource area itself.

Quantities of produced other gases (besides hydrogen) are based on the fraction of hydrogen in the gas (H_2frac, introduced as part of the resource assessment). Estimation of $UR_{othergas}$ (the volume of non-hydrogen gases per unit area at standard conditions) is as follows:

$$UR_{othergas} = H_2UR \,/\, H_2den \,/\, H_2frac \times (1 - H_2frac) \tag{21}$$

where H_2UR = produced hydrogen in mass units and H_2den = hydrogen density at standard conditions.

2.4. Well count and resource area required

Indicative development metrics, i.e. well counts and resource-area required to supply a certain quantity of hydrogen, are anchored to the estimates of hydrogen resource density and well production rates made for each of the play-type examples.

The number of producer wells necessary to achieve a contractual rate of supply can be estimated as:

$$\#\text{-}of\text{-}Wells = H_2supply \, / \, H_2wellrate \tag{22}$$

where $H_2supply$ = the contractually-committed rate of hydrogen supply per year and $H_2wellrate$ = the annual hydrogen production per well.

The amount of resource area necessary to sustain supply over a given contract-period, can be estimated as:

$$Area = (H_2supply \times \#years) \, / \, ([H_2IP + H_2recharge \times \#years] \times RF) \tag{23}$$

where H_2IP =in-place hydrogen resource density (hydrogen per unit area); *#years* = the contractually committed supply period; $H_2recharge$ = H_2 recharge-rate per unit area per year; and RF = hydrogen recovery factor.

Global hydrogen charge-rates may be between 25 Mt to 25,000 Mt (million tonnes) per year ([11] [16]). Considering the earth' surface area of 510 million km^2, this means between 0.05 to 50 ton/km^2/year. We assume a base-case of no significant recharge (i.e. $H_2recharge$ = 0), with an upside case of 50 ton/km^2/yr (upper end of the global range).

We use different hydrogen offtake opportunities as hypothetical projects (Figure 1). Contractual supply-commitments of 7 years are assumed (a reasonable minimum for long-term gas sales agreements [30]).

3. Results

In theory, subsurface hydrogen systems should comprise the same elements as petroleum systems: source, reservoir, trap and seal [15] [31] [33]. However, much of the suspected hydrogen sources are outside sedimentary basins and in settings where favourable conditions may be rare. In case of seal-breach, reservoir layers may still contain hydrogen but most of it will be in aqueous phase since residual quantities of hydrogen gas in breached traps and hydrogen gas saturation in advective migration pathways may be low [15]. The critical gas saturation in hydrogen-brine systems is low due to the small molecule size and high volatility of hydrogen [33], consistent with the observed onset of hydrogen mobility at very low gas saturation in relative permeability experiments [32] [34].

Preservation of hydrogen is fundamentally different from that of hydrocarbons. Hydrogen is a reducing agent that can react abiotically with oxidized species (e.g. nitrate, sulphate, carbonate, pyrite) in the presence of a catalyst and/or at high temperature. Microbial mediation may also facilitate electrons transfer and considerably accelerate the reaction rates [35][36]. Preservation is not taken into consideration here, but is another exploration risk factor.

We categorize hydrogen finds and prospects into three generic hydrogen play-types:

1. Focused-seepage plays where there is an active hydrogen source but limited (if any) subsurface trapping of gaseous hydrogen. In such systems, hydrogen concentrations may reflect localized migration pathways, mostly of dissolved hydrogen.
2. Coalbed hydrogen plays where hydrogen is adsorbed on a molecular scale in coals or other organic matter.
3. Reservoir-trap-seal configurations with a gaseous hydrogen column trapped underneath an impermeable seal, similar to a conventional gas field.

The following paragraphs describe these different play-types from a development-potential perspective, illustrated with actual field examples.

3.1. Focused-seepage plays

This play-type describes settings where there is active expulsion of hydrogen from subsurface sources (e.g. hydrothermal serpentinization of ultramafic rocks, deep-mantle degassing or radiolysis of formation water) with but limited (if any) trapping of gas-phase hydrogen. Without trapping, buoyancy forces drive the expulsed hydrogen upward where it will eventually leak out at surface. Subsurface heterogeneity will funnel hydrogen into discrete migration pathways such as fault/fracture zones or laterally extensive permeability "thief zones" like karst horizons. Outcropping migration pathways may result in surface-seeps and corresponding surface expressions (SCDs or "fairy circles" although these don't necessarily indicate deep-rooted seepage [37]). Hydrogen is believed to migrate mostly via relatively fast advective flows [15] and possibly in diffusive flows where migrating through relatively tight formations at slow rates and with long residence times. Formation waters in and around migration pathways may be saturated with hydrogen alongside small amounts of residual hydrogen-gas. Wells intercepting such pathways may see hydrogen gas shows. When pressure drawdown is applied (if drilling underbalanced as was reportedly done at Bougou in Mali [3], with a downhole sampling tool or during a flowtest), formation-water solubility of hydrogen reduces and some hydrogen will be released in gaseous phase and flow into the well.

Recent research indicates that hydrogen fluxes from deep subsurface to atmosphere may be much more significant than what had been assumed before (e.g. [11] [16]), and natural hydrogen seeps may also be relatively common.

3.1.1. Field example: Bougou (Mali)

The Bourakebougou (Bougou) field in Mali features the world's first hydrogen producer-well, Bougou-1 which production-tested 1,500 m^3 a day (0.13 ton/day) of nearly-pure hydrogen from an interval 60 to 112 m below surface [3] [38]. Following the test, Bougou-1 was used for non-commercial supply of hydrogen to a power generator in the nearby village at a nominal rate of 5 ton per year [2] [39]. Subsequent appraisal wells showed that the reservoir produced by Bougou-1 is a karstified and fractured but otherwise rather tight dolomite stringer sandwiched between dolerite sills (Figure 2, Figure 3) [2] [3]; this zone is called "Reservoir 1". The deeper stratigraphy down to granitic basement (Fig. 5) consists of tight sandstones (3-6% porosity; some with gas shows but not flow-tested), carbonates, shales and dolerite sills. Deeper mudgas shows appear to be weaker than the "Reservoir 1" shows but unfortunately, due to the varying scales of mudgas logs of the different Bougou wells as published in open domain [2] [40] it is difficult to quantify the difference. This paper therefore uses a qualitative assessment of the strength of mudgas shows (Figure 5). The structure is a gentle anticline that plunges to the north and opens to the south. Reservoir pressure down to basement appears to follow a hydrostatic trend [2].

It has been suggested [40] that a dolerite sill above “Reservoir 1” acts as an effective top seal for entrapment of hydrogen gas. However, our review of available open-domain data suggests that a large, connected gascap of significant height (exerting significant excess-pressure at the structure crest) in Bougou is unlikely, for the following reasons:

1. Lack of a relationship between presence (and intensity) of gas shows and structural elevation, despite some 80 m of vertical relief (the elevation difference between the shallowest and deepest wells with gas shows; Figure 2). No base-of-shows can be defined. Moreover, a continuous hydrogen gascap across all wells on the structure (i.e. a gas-column at least 80 m high) would result in crestal reservoir-pressure close to or in excess of lithostatic pressure.
2. Pressure interpretation. Figure 3 shows an estimated Free Water Level by assuming a hydrogen pressure-gradient in the Bougou-1 well and intercepting this with an aquifer-pressure-gradient based on regional groundwater data [41]. It is evident that most of the reservoir must be in the water leg. A small hydrogen gascap may only exist in the uppermost few meters of the reservoir around the crest of the structure.
3. Neutron-density log signatures in the appraisal wells (Bougou-1 was not logged). Across the entire Reservoir 1, including the intervals with hydrogen mud-gas shows, the neutron response deflects towards higher neutron porosities (23 to 35 p.u.) whilst the density log also reads high (2.55-2.75 g/cc; Figure 3 and Figure 4). Density readings in Reservoir 1 are reasonably consistent with a dolomite mineralogy (as recorded in core) albeit a bit low for the modest amount of porosity (on average 4.5% in core). High neutron-porosity in Reservoir 1 is not a gas response but rather related to lithology (presence of water-bearing minerals e.g. clays or diagenetic minerals related to hydrothermal alteration). If the pore-space would have been filled with hydrogen gas, it would result in exactly the opposite effect (as approximated by the red arrow in Figure 4): a lower neutron-porosity (due to the low Hydrogen Index of gaseous hydrogen especially at low pressure) and a lower density (due to the low apparent density of hydrogen gas especially at low pressure).

Bougou is therefore not an accumulation of gaseous hydrogen in a well-defined trap but rather a concentration of aqueous hydrogen (dissolved in formation water), in an area of active seepage between the Taoudeni Basin to the north and the outcropping West Africa craton to the south. Whilst pressure and log data indicate that most of Reservoir 1 is in the water leg, some very small crestal hydrogen gascaps or pockets (isolated clusters of fractures with some gas-fill) may locally exist at the top of the dolomite. Bougou-1 may have intercepted one of these pockets. When Bougou-1 flows hydrogen from this small, local gascap or pocket, some additional hydrogen may release from the aquifer. A 26psi pressure drawdown as applied in the test [38] would nearly halve the initial hydrogen solubility and hence, in the pressure sink around the well, release aqueous hydrogen into the gascap or pocket.

Gas-shows locally observed in the deeper Reservoirs 2 to 5 intersected by the Bougou appraisal wells [3] [2] are much less intense than the gas shows in Reservoir 1, probably because of poor permeability. Shows in these deeper reservoirs are also mostly if not entirely from aqueous hydrogen since there is no indication (from neutron-density log expression or from pressure data) of free-hydrogen gas.

3.1.2. Technical potential

The limited technical potential and large challenges in exploiting a Bougou-type focused-seepage play become clear when considering resource density, productivity, water co-production, required number of wells and required development area.

Resource density and recovery factor. Figure 5 lists the parameters used to calculate the hydrogen in-place resource density for Reservoirs 1 to 5. Because the vast majority of reservoir-interval is in the waterleg whilst gascaps, if any, are very small and localized, the aqueous hydrogen method (equations 1 to 9) was used. Reservoir properties are based on well-log panels and core data [2] [40]. To calculate hydrogen solubility (C_i), a hydrostatic pressure is assumed [2] whilst reservoir temperatures are estimated using a 31 °C surface temperature and the 15.6 °C/km geothermal gradient from Bougou-6 and regional data [42]. Dissolved gas is assumed to be 98% hydrogen as in Bougou-1 [2] [3]. An in-place resource density (H_2IP, aggregated hydrogen per unit area across Reservoirs 1 to 5) at Bougou is then estimated at around 3,000 ton per km^2 (Fig. 5).

To estimate hydrogen recovery-potential, an average depletion of 40 psi is assumed across the entire resource area. For the shallow Reservoir 1 dolomite stringer, 40 psi depletion would lower reservoir pressure to near-atmospheric, i.e. further depletion is not possible. The deeper reservoirs are at higher pressure but permeability is very low (low productivity hampers depletion of large areas) whereas aquifer size could be substantial. Depleting individual zones differentially would require dedicated wells or some form of downhole control in commingled wells, which would significantly increase cost. The uniform 40psi depletion across all reservoirs is consistent with a simple and minimum-cost well concept of commingled completion without individual zone control (Figure 6).

A 40 psi average resource-area depletion results in a recoverable hydrogen resource density (H_2UR) for Bougou of around 150 ton hydrogen per km^2 (a recovery factor of 5%; Figure 5).

Production-rates per well. The observed range in flowrates in Bougou-1 is between 5 ton per year (nominal production-rate) and 1,500 m^3/d (50 ton/year; the 1-day flowtest rate [38]). However, Bougou-1 was not optimized for gas production (drilled as a water well it may have a high skin) and it produces only from Reservoir 1. Figure 6 depicts some speculative improvements in well flow-rate, estimated using industry-standard techniques (pseudo-steady flow equations, assuming 50mD permeability in Reservoir 1 consistent with the Bougou-1 flowtest and 0.1-1 mD in the deeper zones). Tentatively, a low-skin, commingled multi-zone well as in Figure 6 may be able to produce some 830 kg hydrogen per day (300 ton per year): 6 times the Bougou-1 test-rate. To sustain this rate, individual wells must effectively drain large areas as the recoverable hydrogen resource density (H_2UR) is only around 150 ton hydrogen per km^2.

Water production and other byproducts. To estimate anticipated water production we assume (conservatively) that aquifer size is limited to the resource area only, depleting the ca. 87.5 MMrb per km^2 of formation-water porevolume across Reservoirs 1 to 5 by some 40 psi. This would require lifting about 0.34 MMstb of water per km^2.

Gas produced from Bougou-1 is nearly pure hydrogen (98% of H_2, 1% of N_2 and 1% of CH_4; [3]). Production and disposal of non-sellable gases would therefore not be an issue at Bougou.

Development-project metrics. Table 2 shows required number of wells and required development area for a range of hypothetical developments at Bougou. To achieve *industrial*-scale offtake maintained over a multi-year contract, many hundreds to thousands of wells would have to be drilled across thousands of km^2, many times the area appraised to date. Hundreds of millions to billions of barrels of water would be produced; processing and evacuation or disposal of this water would be a major undertaking.

Local offtake-opportunity projects are less overwhelming but nevertheless, committing to several years of offtake would require drilling up areas larger than the appraised Bougou structure. As cumulative water production might be in the order of 20 to over 400 million barrels, water management would be a significant task.

If natural hydrogen recharge is 50 ton hydrogen/km^2 per year (the high end postulated by [11]), the size of the required development area reduces by 10 to 17% depending on project scope (Table 2). Water production may also reduce by the same percentage. The initial well count would not change because it is driven only by offtake requirement and well productivity.

3.2. Coalbed hydrogen plays

This play-type describes settings where hydrogen gas is adsorbed onto the molecular fabric of coalbeds or other organic material. Coals can adsorb significant quantities of gas, preferentially methane but also hydrogen. Experimental data [43] show that the isotherm curves which describe adsorption capacity of hydrogen in coals increase with pressure and decrease with temperature (similar to methane and CO_2). In principle, hydrogen adsorption in coals does not require structural trapping. Hydrogen is not uncommon as a component of coal-mine gas [11]. It usually occurs in proportions of less than 30% mixed with other gases, notably methane and CO_2.

3.2.1. Field example: Lorraine (France)

Folschviller-1 in Lorraine (France) is a coalbed-methane (CBM) test well where hydrogen shows were reported by operator France De Energie (FDE) [4]. Gas shows were detected in a succession of Carboniferous coalbeds of 4 to 13 m net thickness, intercalated with sandstones and shales [44] [45] (Figure 7). The gas is predominantly methane but hydrogen content increases with depth from 6% hydrogen at 760 m to 20% at 1250 m. Measured gas contents in the coal seams vary between 7 to 10 m^3 per ton [44]. Reported permeabilities are between 0.5 to 4 mD and declining with depth as is usual in CBM assets [46].

3.2.2. Technical potential

The large challenges in exploiting a Lorraine-type coalbed hydrogen play become clear when again considering resource density, productivity, water co-production, required number of wells and required development area.

Resource density and recovery factor. Figure 7 lists the input parameters used to calculate hydrogen in-place resource density for the six major coal seams identified in Folschviller-1. Coal-seam thickness (h), density (RHO_b) and gas content (taken as raw, i.e., GC_{raw}) are based on data released by European Gas Limited and FDE [44] [45]. The hydrogen fraction (H_2frac) is based on FDE [4] and extrapolated along the trend of increasing hydrogen fraction with depth for seams without data (Figure 7). Total gas in-place per unit area (aggregated across all coal seams) is then estimated at around 900 MMsm^3 per km^2 (equation 10). In-place hydrogen resource density (H_2IP) is around 120 MMsm^3 per km^2 (13% of gross gas); in mass terms this equated to around 10,900 ton hydrogen per km^2 (equation 12).

Assuming a recovery factor of 50% (reflective of the optimistic end of CBM analogues [47], recoverable total gas (*GasUR*) in a hypothetical Folschviller-type development may be around 450 MMsm^3 per km^2 whilst recoverable hydrogen resource density (H_2UR) might be around 60 MMsm^3/km^2; in mass terms 5,400 ton hydrogen per km^2 (equation 13).

Production-rates per well. Rates per well have been based on analogue developments, anchored to the resource density and distribution observed within the Folschviller-1 well. Because individual coal seams in Folschviller are relatively thick (several meters) with many tens of meters of interburden in-between (Figure 7), development wells would likely target individual seams (e.g. multi-lateral in-seam wells). This concept would give a more effective depletion (consistent with the high recovery factor) compared to commingled wells. Effective depletion would also require dense drilling, possibly in the range of 500 m spacing (4 wells per km^2; [48] [49], again consistent with the relatively optimistic assumption of a 50% recovery factor). Hence, a development of Folschviller may involve some 24 wells per km^2 of resource area (6 seams, 4 wells per seam per km^2).

Gross gas recovery per well can then be estimated as follows: *GasUR-per-km²* / *#wells-per-km²* = 450 / 24 = 19 $MMsm^3$, of which 2.5 $MMsm^3$ (226 ton) is hydrogen. Considering that typical plateau durations in CBM wells are around 3 years and 50% of the well UR may be produced on plateau [46], plateau-rate of a well could be in the order of $0.5 \times 19 / (3 \times 365) = 8.6$ Mm^3 per day (300 Mscf/d) of gross gas; in line with similar CBM developments [46]. Hydrogen plateau-production may be around 1.2 Msm^3 per day per well or 40 ton per year per well.

Water production and other byproducts. Water production was estimated using material balance (equations 19 to 21). Initial reservoir pressure ranges from 1,100 psi in the shallowest coal-seam to 1,800 psi in the deepest seam and we assume that continued fluid lifting to depressurize and desorb gas from the coals could eventually deplete pressures to 300 psi. Porosity from Lorraine coal samples is around 6% [50] which, combined with the seam thicknesses shown in Figure 7, indicates a coal-seam pore volume per km^2 of around 24 MMrb. Assuming a coal compressibility of 6.8×10^{-7} [51] and water compressibility estimated based on pressure and temperature via McCain correlation [27], suggested water production is around 0.34 MMstb per km^2. Assuming 24 wells per km^2, this equates to around 14 Mstb per well.

Only some 13% of the Folschviller gas is hydrogen, the remaining 87% is predominantly methane [4]. To successfully commercialize hydrogen as a sales product by itself, it would have to be separated from methane.

Development-project metrics. Table 3 shows indicative development-metrics for a range of hypothetical projects at Folschviller. Thanks to a relatively high resource density (considerably higher than at Bougou), the resource-areas that would need development to commit to commercial offtake are relatively modest in size. But because well productivity is low, many hundreds to several thousands of development wells would have to be drilled for industrial-offtake levels. Local-offtake opportunities could possibly be supplied with less than hundred wells. Water production would be less than for the focused-seepage play-type (Bougou) but still considerable especially for industrial-offtake scale projects. Handling and evacuation or disposal of this water would add project complexity and cost. Hydrogen recharge has a negligibly small impact on development metrics because the resource density is high compared to the possible rate of recharge.

3.3. Reservoir-trap-seal plays

This play-type model combines an active hydrogen source with a favourable trapping configuration involving one or more porous and permeable reservoirs capped by effective seals, analogous to conventional gas fields [15]. Existence of this play-type remains speculative: no convincing free-gas accumulations have been discovered as yet.

3.3.1. Field example: Monzon prospect (Spain)

The Monzon prospect in Aragon [52] [53], is used here to illustrate the hypothetical potential of a trapped accumulation of gaseous hydrogen. The structure consists of a faulted, basement-cored anticline [53]. The main reservoir is the Triassic Bunter sandstone (at 3600 m depth, average porosity ~10%), which is sealed by an 1800 m thick interval of evaporites and shales. 2D seismic supports the presence of a valid trap. A 1963 exploration well (Monzon-1; Figure 8), recorded hydrogen gas-shows but presence of free gas remains ambiguous.

3.3.2. Technical potential

The technical development potential of a Monzon-type hydrogen play becomes clear when considering resource density, productivity, water co-production, required number of wells and required development area.

Resource density and recovery factor. Figure 8 lists the input parameters used to calculate hydrogen in-place resource density for the Bunter reservoir in Monzon. Assumptions on reservoir thickness, porosity, water saturation and speculative presence of a 60 m hydrogen column in the trap (height measured from crest to the Gas Water Contact) are based on petrophysical analysis of the Monzon-1 well logs [52] and regional data (reservoir pressure and temperature to compute gas Formation Volume Factor). A nearly-pure hydrogen gas fill (98% of total gas) is assumed as per the interpretation of Monzon-1 mud-gas data [53]. Free hydrogen-gas per unit area is calculated with equations 14 to 15. Added to this are the (much smaller) amounts of hydrogen that may be dissolved in the water leg and in capillary-trapped water of the gasleg (equations 1 to 5). Use of these methodologies and assumptions results in a prospective hydrogen in-place resource density (H_2IP) at Monzon of around 455 MMsm^3 per km^2 or in mass terms, 43,000 ton hydrogen per km^2.

Assuming a pure depletion drive and an abandonment pressure of 850 psi, the prospective recoverable hydrogen resource density (H_2UR) may be around 385 MMsm^3 per km^2 or in mass terms, 35,000 ton hydrogen per km^2 (equation 18; Figure 8); a recovery factor of 81%.

Production-rates per well. Indicative production rates per well for a hydrogen gas-field at Monzon have been based on natural gas-field analogues. Assuming a well-spacing of one well per km^2 [54] [55], wells that produce 5 years at plateau and 80% ultimate recovery (around 300 MMsm^3) at plateau, gas plateau rate per well could be around 170 Msm^3 per day (6 MMscf/d); ~ 5,500 ton hydrogen per well per year). Calculations using pseudo-steady-state gas flowrate theorem confirm that even a small-diameter (6”) vertical well with modest drawdown (a few 10s of psi) should be able to achieve 6 MMscf/d gas offtake as long as reservoir permeability is at least a few 10s of mD. Alternative well designs (e.g. larger wellbore diameter, horizontal wells) could possibly achieve higher offtakes but economic viability of such more complex and costly well concepts would obviously depend on field resource-size, commercial demand and evacuation-system capacity.

Water production and other byproducts. Under the assumption of a gascap of reasonable thickness (allowing perforations in producer wells to have some standoff from the gas-water-contact) and a weak, inactive aquifer, no significant water production would be expected. Similarly, with a gascap consisting of nearly-pure hydrogen, production and disposal of non-hydrogen gases would not be an issue.

Development-project metrics. Table 4: Development metrics calculated for a number of hypothetical hydrogen development projects for the Monzon prospect (Spain) under the assumption of a hydrogen gas-field outcome. shows indicative development-metrics for a range of hypothetical development-projects at Monzon. Evidently, a Monzon-type hydrogen gasfield of high purity would be able to supply hydrogen to industrial facilities with a manageable number of wells, and sustain supply for a number of years. Supply to a large facility (e.g. an ammonia plant), however, would require a sizeable gas field (~58 km^2 and an ultimate recovery of ~22 Bm^3). Hydrogen recharge has a negligible impact on development metrics because the resource density is very high compared to the possible rate of recharge.

3.3.3. Sensitivity

Alternative subsurface outcomes that still imply free-gas hydrogen in a Monzon-like structure but in smaller quantities and in more challenging settings illustrate the sensitivity of the resource estimates and the impact on exploitation attractiveness. These also show the need for appraisal activities to reduce subsurface uncertainty and risk. Alternative Monzon subsurface outcomes considered here are:

1. A free gascap of same dimensions as the reference case of previous paragraph, but with a lower hydrogen-content of the gas (30% instead of 98%);
2. A smaller gascap (20 m instead of 60 m height measured from crest, avg. net gas-pay 10 m instead of 30 m) above a strong, active aquifer;
3. Aqueous hydrogen only (no gascap).

Table 5 summarizes some of the key resource metrics for these alternative outcomes. For the large free gascap with hydrogen mixed with other gases, the well-count would need to be tripled to achieve the same hydrogen offtake as in the reference case. For the same hydrogen production, gas processing-capacity would need to be much larger compared to the reference case and separating hydrogen from the other gases would be more involved and costly. If the non-hydrogen gases are non-sellable (e.g. CO_2 or N_2), disposal of these gases would add further complexity and cost.

For the smaller gascap with large, active aquifer, gas in-place resource density is smaller (60% of the reference-case) but more importantly, the recovery factor drops to 31% (vs. 81% in the reference case) because the aquifer combats deep reservoir depletion and residually traps a lot of gas at high pressure. Consequently, hydrogen recovery is only 1/5th of the reference case. Reduced well productivity is reflective of shorter completion intervals (lower net) and lower drawdown to mitigate water coning. Wells may produce significant quantities of water in later life (Table 4 assumes a water-gas-ratio of 1 stb/Mscf for the final 20% of gas production).

For the case of dissolved hydrogen only (without a free gascap), in-place resource density reduces to some 14% of the reference outcome. But more significantly, recovery potential reduces to some 100 ton hydrogen per km^2 (compared to 34,000 ton hydrogen/km^2 in the reference outcome) due to the difficulty involved in depleting aquifer pressures (recovery factor is only 2%). Moreover, material balance calculations suggest that to achieve this recovery some 31 MMstb of water per km^2 would have to be lifted from the wells and subsequently managed at surface.

4. Discussion

The case-studies shown in this paper illustrate the differences in development potential for the different natural hydrogen play-types.

4.1. Development potential of focused-seepage plays

In focused-seepage plays, predominance of aqueous rather than gaseous hydrogen leads to a modest hydrogen in-place resource density, a low recovery factor and low hydrogen production-rates per well. Production-rates may be difficult to increase especially in fields where the hydrogen resource is spread across multiple reservoir zones. To progress towards commercialization, high priority should be on flow-testing appraisal wells to establish whether commercial rates can be achieved.

Large volumes of water will be co-produced with the hydrogen unless offtake is limited to wells targeted at localized crestal gascaps or pockets like the Bougou-1 producer. Since localized gascaps will be small in size and may be difficult to locate, such a targeted development would only develop a small portion of the resource with a very modest offtake. A strategy of dense grid-drilling of low-cost wells could facilitate the depletion of larger areas. In confined aquifer settings it will be easier to deplete pressures effectively with less water production compared to producing aqueous hydrogen from large regional aquifers. Producing large volumes of water may not be an issue in dry areas where water is a precious resource; in fact, it could add value as long as the water can be processed to irrigation or drinking quality. But in regions where there is no demand for large volumes of water or in regions with strict regulations with regards to aquifer depletion or in settings where produced formation-water is unsuitable for consumption, water handling and disposal could add substantial complexity and cost.

Active hydrogen recharge could allow for a smaller developed area but it does not affect the initial required well-count. Focused-seepage areas could receive recharge rates higher than global average but the 50 ton of hydrogen recharge per annum per km^2 considered in this study is already substantial. In the Bulqizë chromium mine in Albania, a series of mine shafts intersecting a large faultzone were found to vent 200 ton of hydrogen per year [5], four times the recharge rate we assumed. Such extreme seepage-rates may be encountered locally around faults but unlikely as an average over resource areas of many tens of km^2. For development projects spanning large areas, recharge is unlikely to make a material impact.

Development metrics calculated on the Bougou case (Table 2) suggest that only local-offtake opportunities might be pursuable. Unrealistically large well counts and water-handling/disposal capacity would be needed to meet industrial-size offtake.

Gas in Bougou has a hydrogen content of 98%. Lower purity would proportionally reduce the already marginal hydrogen resource density and with the added cost of surface separation of hydrogen from other gases and (if the other gases are non-sellable like CO_2 or N_2) and disposal of those gases, commercial viability would become even more challenging. On the other hand, Helium, frequently associated with natural hydrogen [7][56], could add value to a development.

The high well counts and large water management facilities required in focused-seepage developments come with their own energy needs to manufacture, install and operate. These would take away significant portions of the white hydrogen energy-benefits.

4.2. Development potential of coalbed hydrogen plays

The Lorraine case demonstrates that in coal-seam hydrogen plays, in-place resource density can be substantial thanks to the large gas-adsorption capacity of coals. Gas recovery potential can also be good, better than in focused-seepage plays as long as wells are closely-spaced. However, CBM production analogues suggest that well productivity will be low due to the low permeability of coals, especially at larger depths (productivity floor may be around 1,200 m below surface [46]). Moreover, to depressurize the coals large quantities of water will have to be lifted from the wells and managed at surface. Finally, the hydrogen fraction in the total adsorbed gas may be low (as it is in Lorraine) due to the much higher adsorption capacity of gases like CO_2 and methane. Techniques to separate hydrogen from other gases are a topic of ongoing research [57] [58] and to generate a sales stream of sufficient hydrogen-purity could be challenging and costly [59]. Volumes of methane produced alongside hydrogen could be commercialized but producing and selling natural gas would bring about a substantial GHG footprint for the project as a whole. In the case of Lorraine for example, methane volume is eight times the hydrogen volume.

Development metrics calculated on the Lorraine case (Table 3) suggest that only local offtake opportunities might be pursuable. Unrealistically large well counts would be needed to meet industrial-size offtake. Unlocking the development potential of coalbed hydrogen would require addressing the many environmental concerns that have hampered CBM developments e.g. water management and surface footprint [46] [60]. Energy needs to manufacture, install and operate wells and surface equipment may erode significant portions of the white hydrogen energy benefits.

4.3. Development potential of reservoir-trap-seal plays

The Monzon case demonstrates that reservoir-trap-seal plays can have a very high hydrogen in-place resource density if the hydrogen purity is high. Also, due to the much higher effectiveness of gascap expansion, recovery factor can also be high (up to 80% or more depending on initial pressure and availability of compressors) unless the gascap height is very small and/or aquifer-influx is strong. Well productivity may also be high if the reservoir has some meaningful permeability. Development metrics calculated for the Monzon reference-case (Table 4) suggest that industrial-scale offtake could be pursued with a few tens of producer wells. However, to commit long-duration supply to a large industrial facility like an ammonia plant, a resource area of several tens of km^2 would be required unless reservoir thickness and properties are much better than at Monzon.

Sensitivity runs of the Monzon case (Table 5) show that if hydrogen occurs mixed with other gases (the reference outcome assumed nearly-pure hydrogen), achieving industrial supply-rates becomes challenging because large volumes of gas need to be produced for a modest hydrogen-yield. If the gas column is small and the aquifer strong, development metrics also deteriorate. A Monzon outcome with aqueous hydrogen instead of a gascap has very poor development potential due to low hydrogen productivity and large water production. This shows how critical it is to confirm presence of hydrogen as a free gas as opposed to hydrogen dissolved in formation water.

Since reservoir-trap-seal plays appear the only play-type that can meet the requirements of large industrial facilities, natural hydrogen exploration-efforts should focus on this type of play to make a material impact on global decarbonization. Gathering extensive reservoir and fluid datasets, especially reservoir pressures and flow testing, in hydrogen exploration/appraisal wells will be key to confirm 1) presence of hydrogen as a free gas, 2) the height of hydrogen gas-columns and 3) hydrogen-purity of the gas.

Conclusions

The three generic hydrogen play-types recognized in this paper (focused seepage, coalbed hydrogen and reservoir-trap-seal systems), have different development potentials. In the focused-seepage play-type which may be relatively common, hydrogen is predominantly dissolved in formation water, with only small and localized gas caps. Analysis of the Bougou find in Mali indicates a modest hydrogen in-place resource density, low recovery factor, low well productivity and high associated water production. This may be typical for focused-seepage plays. Only local-offtake opportunities might be pursuable since unrealistically large well counts and water-handling/disposal capacities would be needed to meet industrial offtake. The impact of hydrogen-recharge on notional development-project metrics appears limited.

In coalbed hydrogen plays like the Lorraine find in France, resource density can be substantial thanks to the large gas-adsorption capacity of coals. Unfortunately, well productivity is low due to the low permeability of coals especially at greater depth. Moreover, coalbed hydrogen plays may typically have a low hydrogen content of the adsorbed gas because of preferential adsorption of CO_2 and methane and the preponderance of these in a coal environment. Developments of coalbed hydrogen may require very high well counts for relatively modest offtake levels. Isolating a hydrogen sales-stream of sufficient purity could be challenging and costly. Unlocking the potential of coalbed hydrogen would require addressing environmental concerns associated with water, large surface footprint and the disposal of significant amounts of co-produced CO_2 and/or methane. Even then, only local-offtake opportunities might be pursuable.

Reservoir-trap-seal plays with a gaseous hydrogen column of significant, like in a conventional gas field, have the best development potential thanks to superior in-place resource density, high recovery factor and high well productivity. Metrics calculated for the Monzon prospect in Spain demonstrate that developments could meet industrial supply needs. However, a tendency for short gas columns (suppressing recovery factors) and low hydrogen content in the gas could create significant downside.

To date, no convincing examples of hydrogen gas-columns of material size trapped in porous and permeable reservoir, have been presented. This may be due to hydrogen's ease of leakage and/or its reactivity (chemical and biological). Exploration efforts should focus on this type of play, to demonstrate whether or not it exists.

Acknowledgements

Bernard Van Dijk provided expert advice on the hydrogen demand-assumptions for local offtake. Chris Atkinson and Tony Lawrence (Helios Aragon) proofread earlier versions of this manuscript and made many helpful comments. Laurent Truche (Université Grenoble Alpes) and an anonymous Journal reviewer made very helpful comments that considerably improved the final version of this manuscript.

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Figures

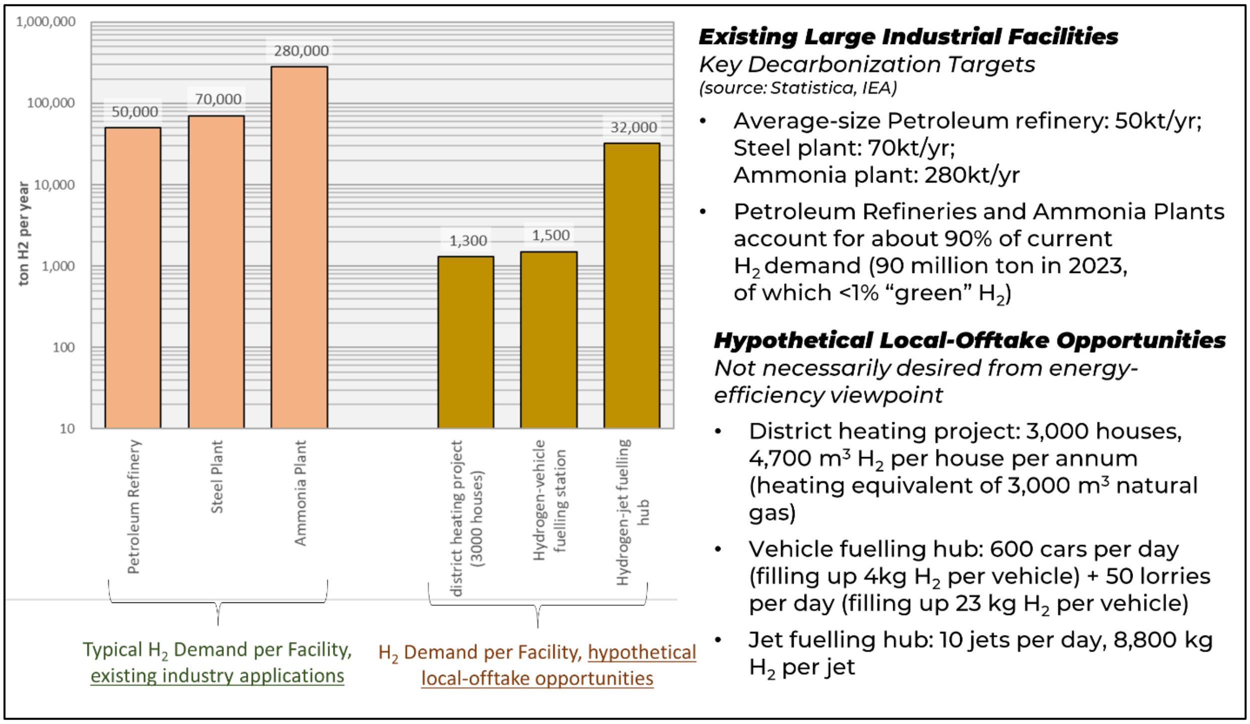


Figure 1: Hydrogen demand for existing and speculative future industry applications.

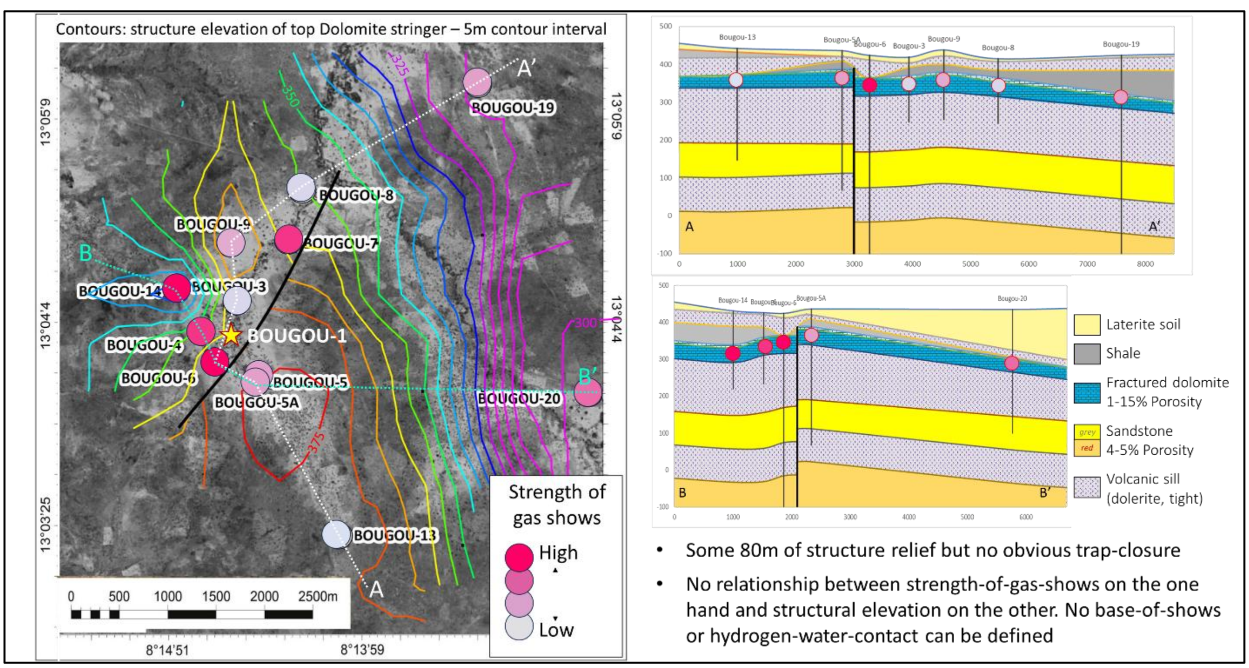


Figure 2: Top Reservoir-1 structure-map (left) and schematic cross-sections (right) illustrating the distribution of gas shows across the structure of Bougou Field (Mali).

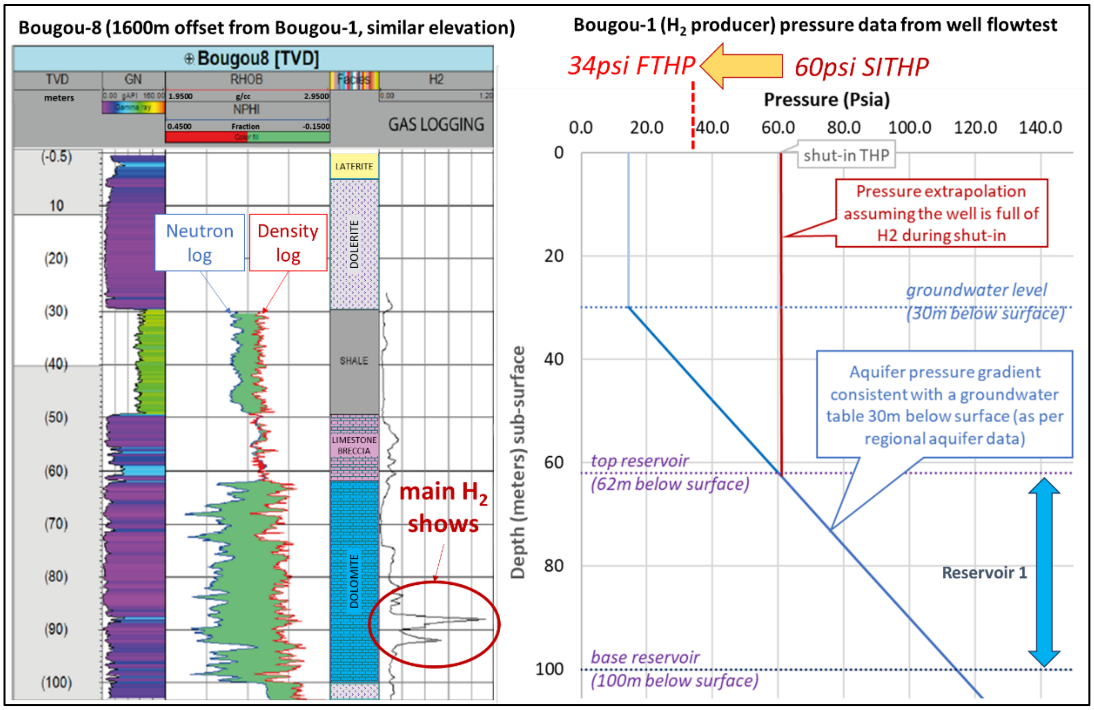


Figure 3: Reservoir-1 pressure interpretation for Bougou field (Mali). Log display of offset well Bougou-8, used to illustrate position of the pressure-inferred Free-Water-Level, is adapted from Maiga et al [2].

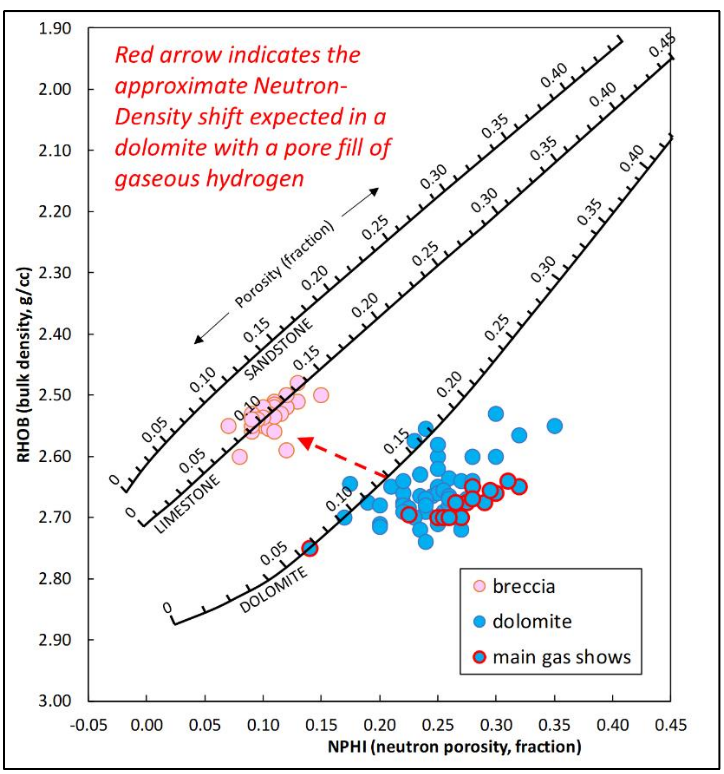
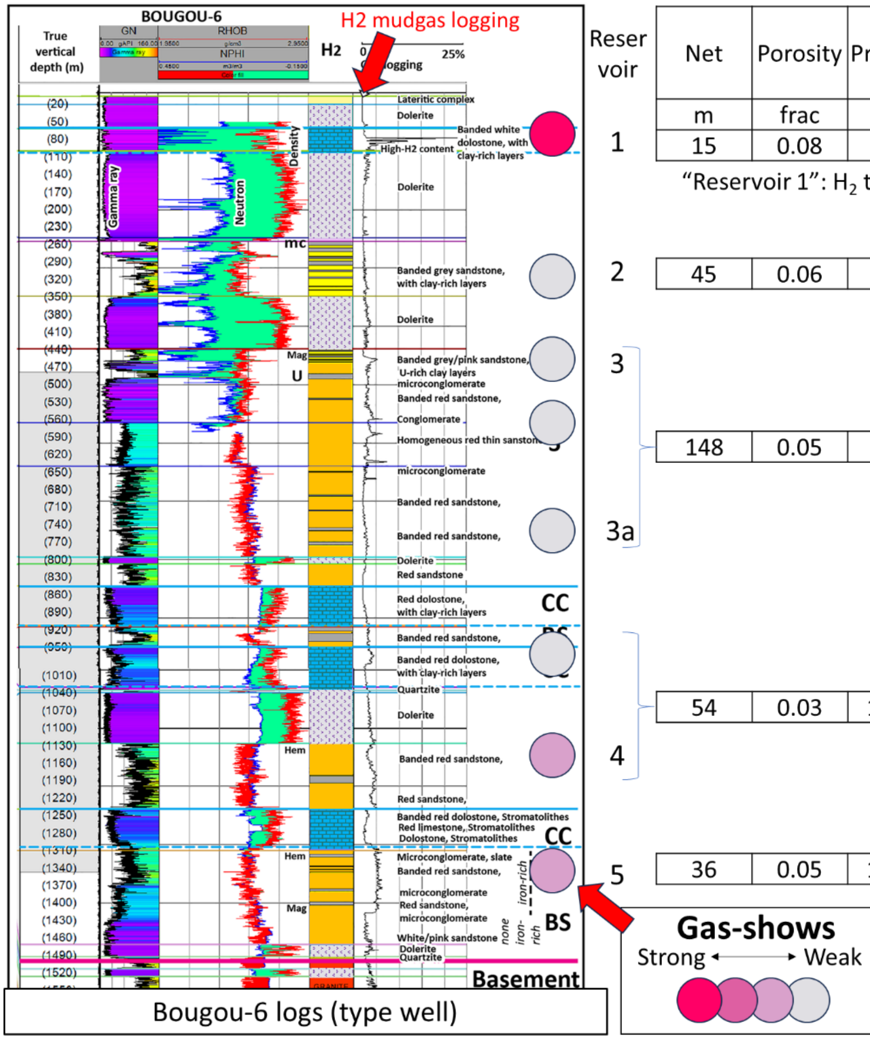


Figure 4: Neutron-density plot for Reservoir-1 in Bougou field (Mali).
Data is from well Bougou-8 (same well as Figure 3).



Reservoir	Net	Porosity	Pressure	Temperature	H2 In-Place	*H2 Recoverable*
	m	frac	psia	degC	ton/km2	*ton/km2*
1	15	0.08	61	32	20	*10*
2	45	0.06	343	35	250	*30*
3, 3a	148	0.05	700	39	1,230	*70*
4	54	0.03	1,585	49	650	*20*
5	36	0.05	1,842	51	830	*20*
				TOTAL	**2,980**	***150***

"Reservoir 1": H_2 test and production in Bougou-1

RF = 5%

Figure 5: Reservoir parameters and estimates of in-place and recoverable hydrogen resource density in Bougou Field (Mali). Well-log display of Bougou-6, used to indicate position of the reservoirs that were assessed volumetrically, is adapted from Maiga et al [2].

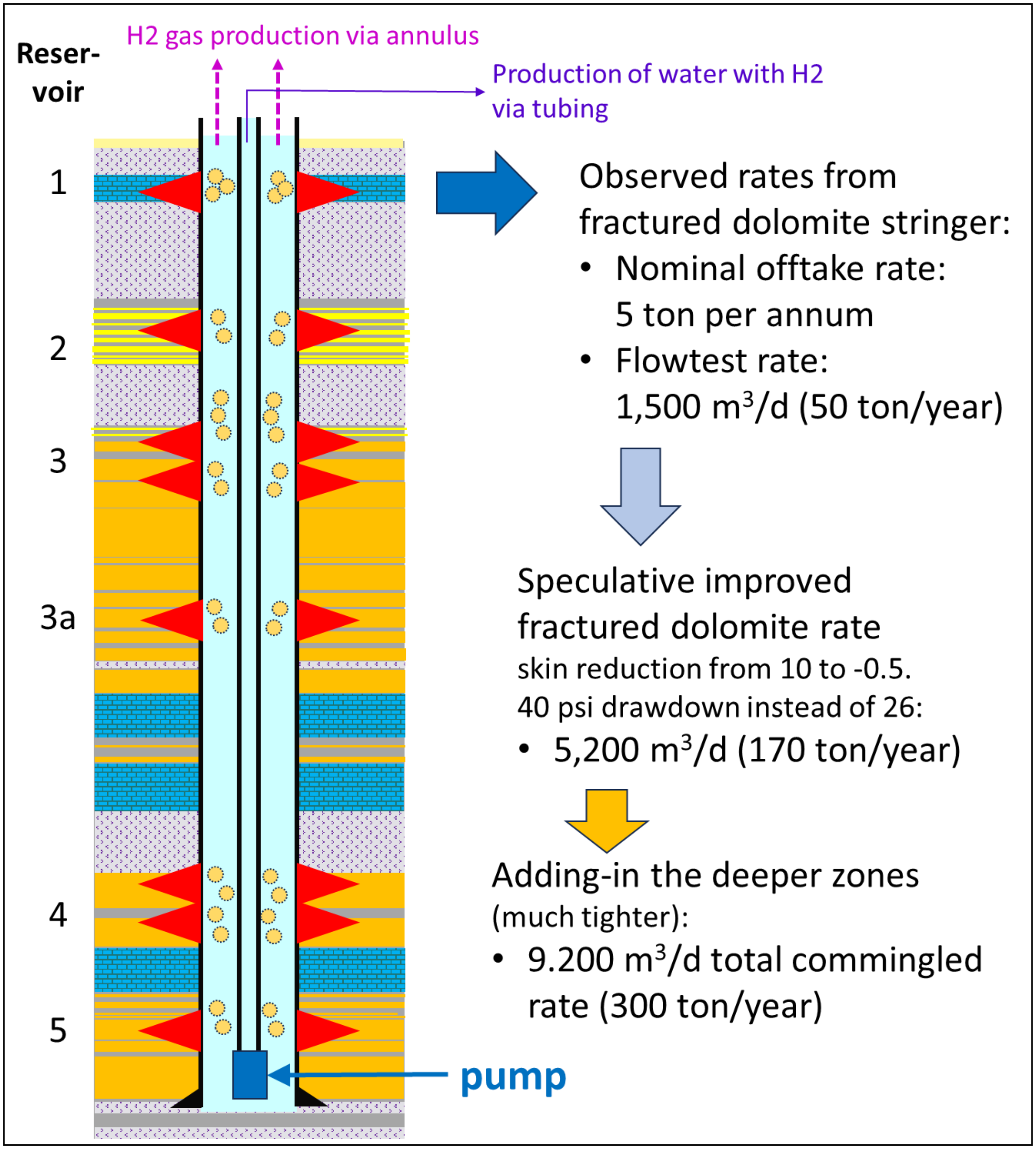
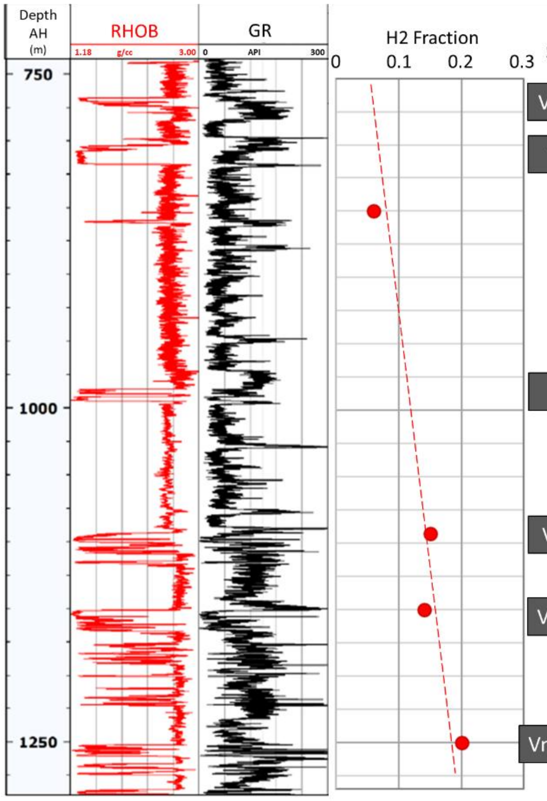
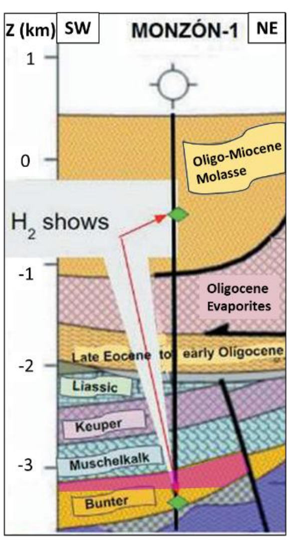


Figure 6: Conceptual design for a multi-zone aqueous-hydrogen producer well in Bougou Field (Mali).



Coal Seams	Net	Density	Gas Content	H_2 Content	Gross GIIP	H_2 in-place	
	m	g/cc	m^3/t	frac	MMsm^3/km^2		*ton/km^2*
V5-6-7	4.5	1.60	7.3	0.06	52	3	*286*
V8-9	13.5	1.40	9.6	0.07	181	13	*1,170*
Vi-i-i	6.9	1.55	9.2	0.13	99	13	*1,124*
Vz-z-y	12.2	1.60	10.1	0.15	197	30	*2,652*
Vα-β-γ	14.9	1.45	9.4	0.14	203	29	*2,559*
Vm-m-n	10.5	1.65	9.9	0.20	171	34	*3,078*
				TOTAL	**903**	**121**	***10,869***

Figure 7: Reservoir parameters and estimates of in-place and recoverable hydrogen resource density for the Folschviller coalbed hydrogen find (France). Well-log panel used to indicate the coals that were assessed volumetrically, is adapted from Allouti et al [45].



Monzon reference-case success outcome
(H_2 gas discovery of 98% purity in Bunter)

	Net	Porosity	Sw	Bgi	H2 in-place	*H2 recove-rable*
	m	Frac	Frac	rm3/sm3	ton/km2	
gasleg	30	0.095	0.364	0.004	37,000	*30,000*
waterleg	25		0.900		6,000	*5,000*
				TOTAL	**43,000**	***35,000***

Figure 8: Reservoir parameters and estimates of in-place and recoverable hydrogen resource density for the Monzon prospect (Spain) under the assumption of a hydrogen gas-field outcome. Schematic cross-section that indicates the reservoir which was assessed volumetrically, is adapted from Atkinson et al [53].

Tables

Parameter	Description	standard Units
Ash	ash content of adsorbent rock	weight fraction
B_{gi}	initial gas formation volume factor	rm^3/sm^3
B_{gr}	depleted gas formation volume factor	rm^3/sm^3
C	porefluid compressibility	psi^{-1}
C_f	rock matrix compressibility	psi^{-1}
C_i	hydrogen solubility at initial conditions	mol/l
C_r	hydrogen solubility at depleted conditions	mol/l
FVF_w	formation water volume factor	rm^3/sm^3
GC_{DAF}	gas content in dry, ash-free adsorbent rock	m3/t
GC_{raw}	raw gas content in adsorbent rock	m3/t
h	reservoir thickness	m
H_2den	density of hydrogen at standard conditions	kg/m^3
H_2frac	hydrogen content (in free or dissolved gas)	fraction
$H_2moleden$	molecular density of hydrogen	g/mol
K_H	Henry's constant for hydrogen	l×atm/mol
Moisture	moisture content of adsorbent rock	weight fraction
NtG	reservoir net-over-gross ratio	fraction
Por	net-reservoir porosity	fraction
P_i	initial reservoir pressure	psia
P_r	depleted reservoir pressure	psia
RF	recovery factor	fraction
RHO_b	bulk density of adsorbent rock	g/cm^3
S_g	total gas saturation	fraction

Table 1: Input parameters into the resource equations 1 to 21.

Metrics	Large Industrial Offtake			Local Offtake Options			Basis
	Petroleum Refinery	Steel Plant	Ammonia Plant	District heating project	H_2-vehicle fuelling station	H_2-jet fuelling hub	
Annual demand (ton/yr)	50,000	70,000	280,000	1,300	1,500	32,000	Typical “average” facility size (Fig.1)
Contractual Supply Commitment	7 years						Minimum for a long-term GSA
Producer-Well Count per Offtake Option							
Wellcount assuming Bougou-1 testrate	*1,000*	*1,400*	*5,600*	*26*	*30*	*640*	*50ton H_2/yr per well*
Well count assuming multi-zone wells	*170*	*230*	*930*	*4*	*5*	*107*	*300ton H_2/yr per well*
Development-Area Size and Water Production (per offtake option, assuming no significant H_2 recharge)							
Resource-Area to be developed (km^2)	2,300	3,300	13,100	50	60	1,240	40psi depletion, EUR 150ton H_2/km^2
Cumulative Water production (MMstb)	790	1,130	4,500	17	21	426	Material Balance, 40psi depletion
Development-Area Size and Water Production (per offtake option, assuming recharge of 50 ton H_2/ km^2/year)							
Resource-Area to be developed (km^2)	2,100	2,900	11,700	50	60	1,240	40psi depletion, EUR 150ton H_2/km^2
Cumulative Water production (MMstb)	720	1,000	4,020	17	21	426	Material Balance, 40psi depletion

Table 2: Development metrics calculated for a number of hypothetical hydrogen development projects at the Bougou field (a focused hydrogen seepage in Mali).

Metrics	Large Industrial Offtake				Local Offtake Options			Basis
	Petroleum Refinery	Steel Plant	Ammonia Plant		District heating project	H_2-vehicle fuelling station	H_2-jet fuelling hub	
Annual demand (ton/yr)	50,000	70,000	280,000		1,300	1,500	32,000	Typical "average" facility size (Fig.1)
Contractual Supply Commitment	7 years							Minimum for a long-term GSA
Producer-Well Count per Offtake Option								
Wellcount assuming CBM-analogue rate	*1,330*	*1,860*	*7,450*		*35*	*40*	*850*	*8.6 Msm³ gross gas/day/well, H_2 = 13%*
Cum. Gross Gas Production (MMsm³)	*28,900*	*40,600*	*162,500*		*760*	*870*	*18,600*	*450MMsm³ gas UR/km², H_2 = 13%*
Development-Area Size and Water Production (per offtake option, assuming no significant H_2 recharge)								
Resource-Area to be developed (km²)	64	90	360		1.7	1.9	41.3	EUR 5,430ton H_2/km²
Cumulative Water production (MMstb)	22	30	121		0.6	0.6	13.9	depletion to 300psi P-abandonment
Development-Area Size and Water Production (per offtake option, assuming recharge of 50 ton H_2/ km²/year)								
Resource-Area to be developed (km²)	62	87	350		1.6	1.9	40.0	EUR 5,430ton H_2/km²
Cumulative Water production (MMstb)	21	29	118		0.5	0.6	13.4	depletion to 300psi P-abandonment

Table 3: Development metrics calculated for a number of hypothetical hydrogen development projects at Folschviller coalbed-hydrogen find (France).

Metrics	Large Industrial Offtake			Local Offtake Options			Basis
	Petroleum Refinery	Steel Plant	Ammonia Plant	District heating project	H_2-vehicle fuelling station	H_2-jet fuelling hub	
Annual demand (ton/yr)	50,000	70,000	280,000	1,300	1,500	32,000	Typical "average" facility size (Fig.1)
Contractual Supply Commitment	7 years						Minimum for a long-term GSA
Producer-Well Count per Offtake Option							
Well count assuming vertical wells	*9*	*13*	*51*	*1*	*1*	*6*	*6MMscf/d (5,500 ton H_2/yr) per well*
Cum. Gross Gas Production ($MMsm^3$)	*3,970*	*5,560*	*22,200*	*100*	*120*	*2,540*	*390$MMsm^3$ gas UR/km^2, H_2 = 98%*
Development-Area Size and Water Production (per offtake option, assuming no significant H_2 recharge)							
Resource-Area to be developed (km^2)	10	14	58	0.3	0.3	6.6	EUR 35,000 ton H_2/ km^2, Pabd 850psi
Cumulative Water production (MMstb)	negligible						
Development-Area Size and Water Production (per offtake option, assuming recharge of 50 ton H_2/km^2/year)							
Resource-Area to be developed (km^2)	10	14	57	0.3	0.3	6.5	EUR 35,000 ton H_2/ km^2, Pabd
Cumulative Water production (MMstb)	negligible						

Table 4: Development metrics calculated for a number of hypothetical hydrogen development projects for the Monzon prospect (Spain) under the assumption of a hydrogen gas-field outcome.

	Large free gascap, nearly-pure H_2 *Reference Case*	Large free gascap, H_2 mixed with other gases	Small free gascap, nearly-pure H_2	Aqueous only, nearly-pure H_2
Subsurface Parameters and In-Place Resource				
Max. gas cap / avg. gas pay (m)	60 / 30	60 / 30	20 / 10	0
Hydrogen Fraction in gas	0.98	0.30	0.98	0.98
In-Place Gross Gas Resource Density (MMsm^3/km^2)	484	484	259	66
Resource Recovery				
Reservoir Pressure (psia) Initial / Final	5,450 / 850	5,450 / 850	5,390 / 4,390	5,360 / 5,260
Recoverable Gross Gas Resource Density (MMsm^3/ km^2)	391	391	79	1.1
Recovery Factor	81%	81%	31%	2%
Recoverable Hydrogen Resource Density (ton/ km^2)	34,000	11,000	7,000	100
Well Productivity				
Gross Gas Production per well (Msm^3/d)	171	171	35	3
H_2 production per well (ton/yr)	5,500	1,700	1,100	10
Water production (MMstb/km^2)	negligible	negligible	0.60	30.9

Table 5: Comparison of key resource metrics for alternative prospect subsurface-outcomes at Monzon (Spain).