Assessing the feasibility of the "all-in-one" concept in the UK North Sea: Offsetting Carbon Capture and Storage costs with methane and geothermal energy production through reuse of a depleted hydrocarbon field

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Abstract

The "all-in-one" carbon storage system involves the co-production of methane and geothermal energy from produced subsurface brines, utilising onsite power generation and carbon capture to run a selfsustaining carbon storage facility. Once the produced brine has been degassed and cooled, CO_2 is dissolved into it, and the CO_2 saturated brine is reinjected where it sinks due to its relatively higher density, providing secure storage. This study investigates, for the first time, the economic feasibility and energy balance of such a system within the UK North Sea. We examine the suitability of a depleted hydrocarbon field, which provides access to a saline formation, located in the Inner Moray Firth, Scotland for such a co-production and reinjection facility. We find that operating such a system to produce gas or electricity for sale alone would result in both an energy and economic loss. However, in the full “all-inone” system scenario, where geothermal energy is used to offset the energy requirements of the capture and injection system, this results in a positive energy balance and a potential revenue stream, whilst also offering additional capacity for storing CO_2 from external sources. Whilst the chosen case study site was non-ideal, it demonstrates that reuse of redundant oil & gas infrastructure that would otherwise be decommissioned, using the all-in-one approach, could help to offset a portion of the financial barriers to developing a carbon storage industry in the UK North Sea.

1 Introduction

1.1 Background

Global carbon dioxide emissions from fossil fuel use must be drastically reduced to limit anthropogenic warming to 2 °C above pre-industrial levels as agreed by the European Union and the 194 signatory states to the Paris agreement. Carbon capture and storage (CCS) involves the capture of CO_2 from point sources followed by long-term storage in geological formations. CCS is the only existing technology that can reduce emissions from industrial processes such as cement and steel manufacture and many forms of chemical synthesis. Combined with the combustion of bioenergy (BECCS), the technique offers the potential of significant negative emissions and is included in numerous future energy modelling scenarios that meet the 2°C target of the Paris agreement (Azar, Johansson and Mattsson, 2013; Scott *et al.*, 2013; IEA, 2014; IPCC, 2014)

Despite the potential emissions reductions offered by CCS, and projections of the long-term cost-effectiveness of it compared with other carbon reduction technologies (e.g. IPCC, 2014), the upfront capital expenditure costs of any CCS project are a significant barrier to its industrial scale deployment. The current financial regimes have yet to produce a sufficiently high carbon price to result in widespread implementation of CCS and hence there have been concerted efforts to make it more cost-effective. Using captured CO_2 to enhance oil recovery (EOR) is one method that has proved to be successful at offsetting some of the capital costs of capture and storage (IEA, 2015; Stewart *et al.*, 2018). Recently, methane and geothermal energy co-production has been proposed as an option at storage sites to generate additional revenue in a similar fashion to CO_2-EOR (Bryant and Pope, 2015; Ganjdanesh and Hosseini, 2016).

1.2 The "All-in-one" concept

Subsurface waters in many sedimentary basins have been found to contain dissolved methane and in some cases these have been commercially exploited to produce natural gas for decades (Marsden, 1979; Mankin, 1983; Littke *et al.*, 1999). Bryant (2013) proposed an onshore "closed-loop" system where brine is extracted from deep, hot, overpressured saline aquifers and the methane separated. The methane and hot brine are sold for power generation and heating respectively. CO_2 captured from the power generation process is dissolved into the now cold brine before reinjection into the subsurface. This closed-loop model emits very little CO_2 and provides scope for disposal of CO_2 from other external sources. CO_2 saturated brine is denser than native brine and sinks, removing the risk of leakage through buoyant migration. Pressure management and brine disposal issues associated with supercritical CO_2 storage in saline aquifers are also addressed through the brine reinjection

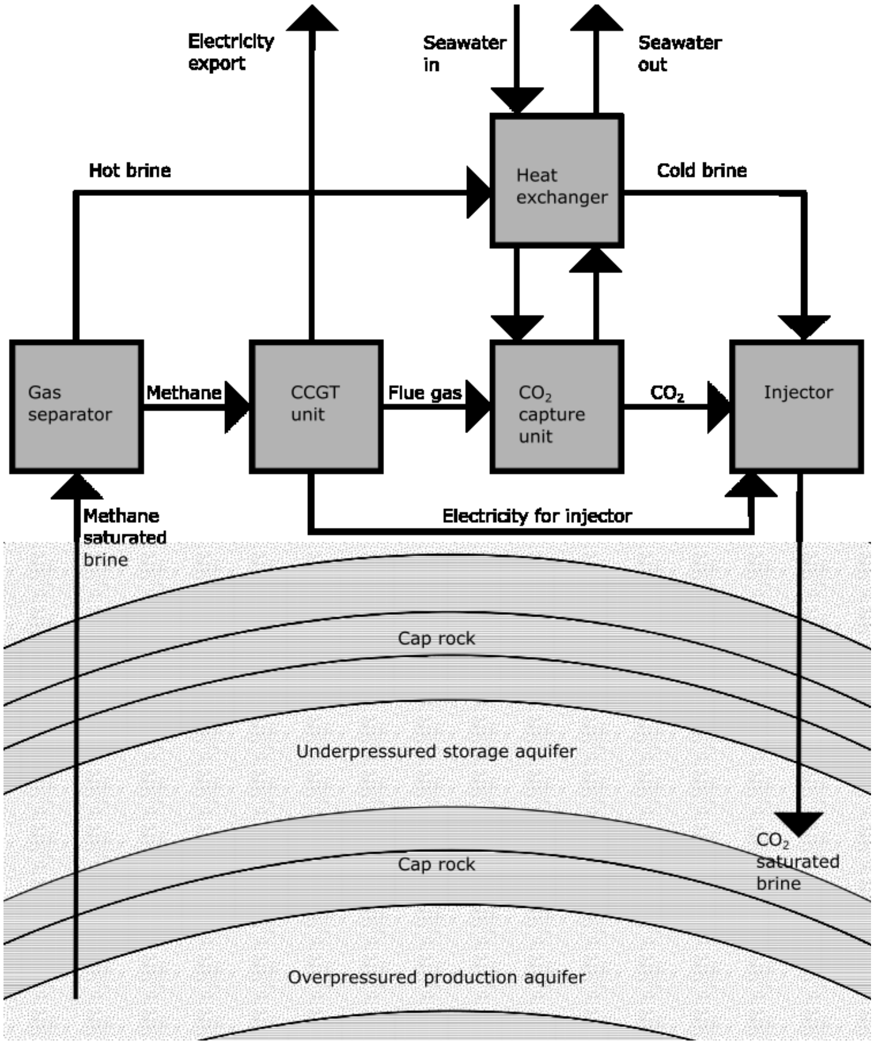

Figure 1: Schematic overview of the all-in-one system, illustrating both the above surface capture and separation process and the subsurface underpressured storage aquifer and overpressured production aquifer required for the closed loop system. process.

Whilst this model has been proposed in theory, no evaluation of its feasibility on a specific site has yet been undertaken. Here, for the first time, we investigate the economic feasibility of an “all-in-one” system (Figure 1) with onsite power generation (gas to electricity) and carbon capture within a depleted hydrocarbon reservoir in the Inner Moray Firth of the UK North Sea. In this system, brine would be produced from saline aquifers in the region utilising existing oil & gas infrastructure. We aim to determine if such a scheme will be economically and technically feasible in an area without access to deep, hot, overpressured aquifers and if reusing oil & gas infrastructure can limit its costs, postpone decommissioning and help open up the UK North Sea to a future carbon storage industry.

The “all-in-one” system builds on the closed-loop system previously outlined by Bryant (2013). In this system, methane is separated from methane saturated brine and used to fuel an onsite combined cycle gas turbine (CCGT). CCGTs are common on offshore platforms (Welander, 2000) with the majority achieving efficiencies of between 50 - 60% , with modern units being the most efficient (Aminov *et al.*, 2016). The “gas-towire” concept is being explored as an option in the UK and a recent report (Oil & Gas Authority, 2018a) suggests that it is both technically and economically feasible to repurpose existing infrastructure and tie-in offshore wind developments to produce electricity from gas. Furthermore the collaboration between gas and offshore wind will help to reduce operating costs and the technology could be applied to offshore hydrogen production as an aid to balancing the intermittency of renewable energy sources.

An onsite carbon capture unit powered by geothermal energy would also be installed to capture the CO_2 produced from the CCGT. In this setup, a post-combustion ammonia capture system will be considered which is significantly more energy efficient with lower capital expenditure (CAPEX) and operating expenses (OPEX) than standard amine capture systems (Sutter, Gazzani and Mazzotti, 2016). The ammonia capture system requires heating and cooling which can be provided by geothermal energy from extracted brine and seawater, respectively.

The captured CO_2 is then dissolved into the brine and reinjected into the subsurface where it sinks due to its relatively higher density. The injection process is powered by a portion of the electricity produced by the gas turbine with the remainder being sold into the national electricity grid. Figure 1 shows a schematic of the whole system. This process has the added benefit of generating low carbon electricity while reusing existing platforms, helping to reduce both CAPEX and OPEX.

1.3 Case study site and aquifers

The aquifers considered in this study are the Mains Formation and the Beatrice Formation which extend around 70 km east from the coast of the

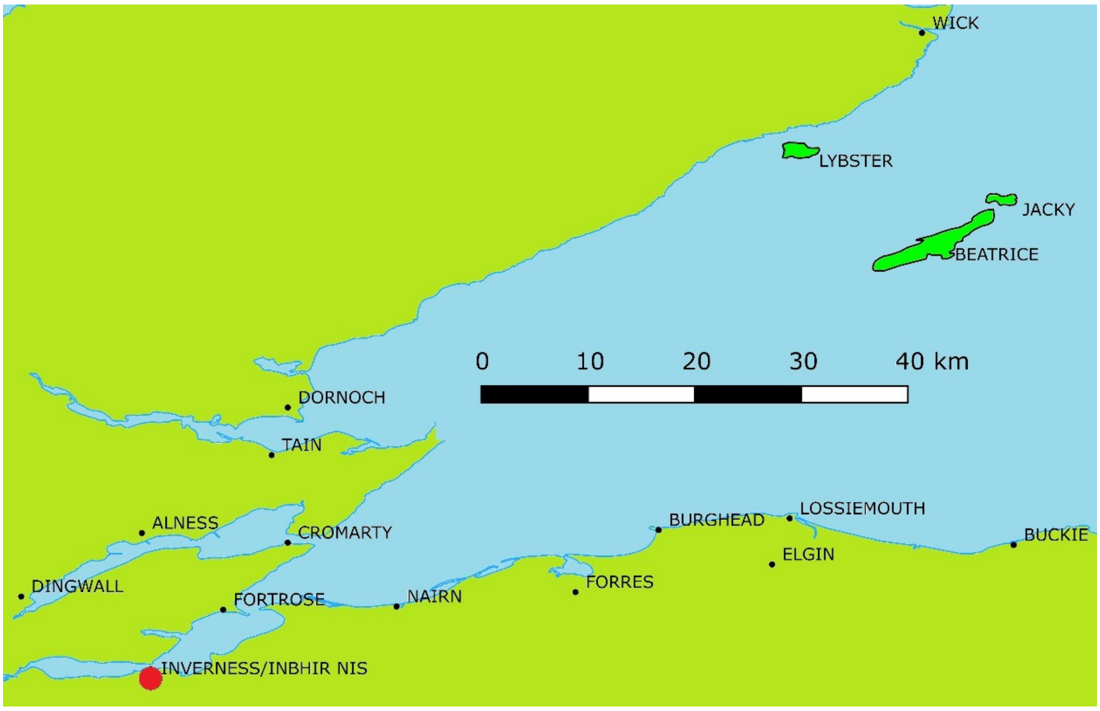

Figure 2: Location of the Beatrice and Jacky oil fields (outlined in black with bright green fill) in the Moray Firth (see Figure 4 for zoom in of oil fields). Made using data from OGA (2018)

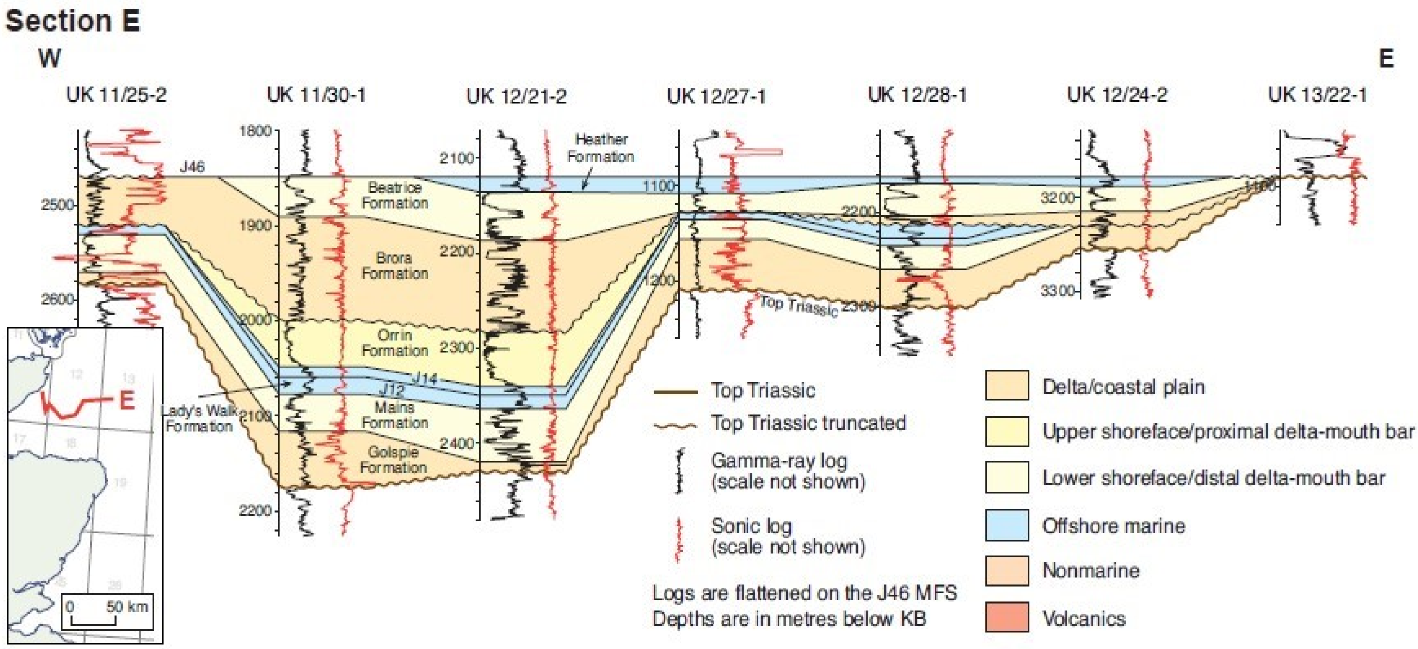

Figure 3: Well logs showing the extent of the Beatrice and Mains formations in the Moray Firth. Adapted from Evans *et al.* (2003)

northern coast of the Moray Firth. These formations are both part of the producing intervals within the Beatrice and Jacky oil fields and hence could be accessed using the oil production platforms associated with these fields located in the Inner Moray Firth (Figure 2). The platforms also have an electrical connection to the UK National grid. The two formations are in at least partial vertical communication as evidenced by the Beatrice field's oil/water contact being located in the Mains Formation with the top of the oil column in the Beatrice Formation.

Field production records indicate that a fault located between the Beatrice and Jacky oilfields (Figure 4) maintains a significant pressure difference between the two fields. These records indicate that the Beatrice oilfield is located within a closed aquifer and the Jacky oilfield is within an open, connected aquifer. This is indicated by the fact that the Beatrice oilfield is underpressured from decades of production and the field required artificial

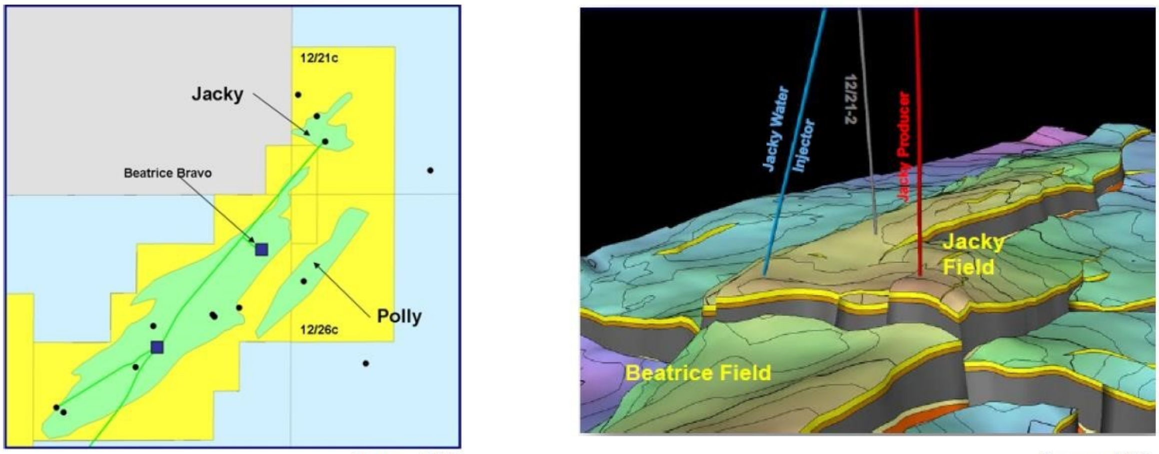

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Figure 4: Left: Map of the Beatrice and Jacky fields with the nearby Polly prospect. Right: 3D model of the Beatrice and Jacky fields showing the fault that separates them along with the 3 Jacky field wells. Adapted from North Sea Energy Inc. (2013)

lift and downhole pumps from the beginning of production (Stevens, 1991). Across the fault in the Jacky oilfield is a large overpressured open aquifer according to production data and well logs. Oil flowed without artificial lift from the Jacky field for almost two years (Ithaca Energy, 2009).

Extraction of methane rich brine from an overpressured aquifer (in this case the Mains formation in the Jacky oilfield) and subsequent CO_2 disposal into an underpressured one (in this case the Beatrice formation in the Beatrice field) would reduce the energy and therefore costs required to run the closed loop system. Hence, the existing relationship between the Beatrice and Jacky oilfields is ideal for this system. Once the pressure on the overpressured side drops substantially due to brine production, disposal can be switched from the underpressured side for pressure management purposes.

2. Evaluating evidence for methane saturation within the oil fields

For the "all-in-one" system to be viable, it is imperative that the extracted brine is saturated with methane. A systematic study of well logs from the Beatrice and Jacky oil fields was performed to test if this was the case for the study site. This focused on the identification of gas trips, background gas levels, and identification of the gas effect in well logs (Figure 5). Alongside this qualitative assessment, saturation calculations using production data were compared with theoretical data from the literature.

2.1 Qualitative assessment

The gas effect (indicating the presence of free gas in pore spaces) was identified in all wells with neutron logs within the oil fields, namely 6 instances in the Mains formation and 15 in the Beatrice formation. Where neutron logs were not recorded there were a further 3 gas shows in the Mains formation and 3 in the Beatrice formation. It was assumed that gas shows were likely to be due to over saturation of brine with methane.

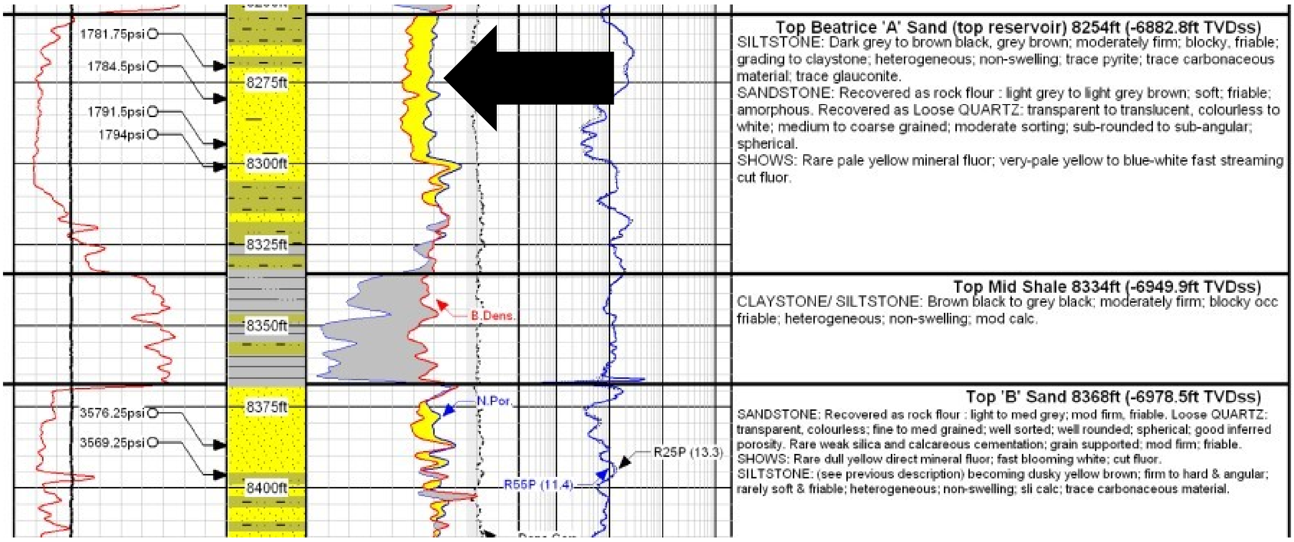

Figure 5: Reservoir section from composite well log for the Jacky field injection well 12/21c-J2 showing large gas effect between 8310ft and 8200ft (marked by large black arrow) on the neutron and density logs which are labelled N. Por. and B. Dens. Respectively. Where the gas effect is present the space between the log lines is shaded in yellow. Note the low pressure in A sand after several years of oil production.

Wells within the Beatrice field exhibited evidence for small amounts of free gas at the top of individual reservoir sands rather than an overall gas cap, strongly implying gas saturation of the brines. Furthermore, no evidence of a gas/oil contact is present in the resistivity logs from the field.

Background gas levels of 0.1-0.8 % occur in many of the wells with a maximum of 3.45 % in well 12/21c-6 in the Jacky field. This is also the case for wells outside of the oilfields. A biogenic origin for gas is suggested in the petroleum geochemistry report for well 12/27-1 as it is dry and isotopically light ($\delta^{13}C$ −55‰), a similar situation to the Russian (Littke *et al.*, 1999) and Japanese (Marsden, 1979) methane saturated sedimentary basins.

Gas shows were also recorded in several wells outside the Beatrice and Jacky oilfields. A gas discovery in the Beatrice formation not associated with oil was found in well 12/27-1, and exhibited a flow rate of 9.5 million standard cubic feet (mmscf)/day (~270,000 m^3/day). Wells 11/24a-2 and 11/24a-2z recorded background gas levels up to 1.42%. Wells 11/30-6, 12/20b-1 and 12/24-2 also recorded gas shows.

The majority of well logs that penetrated the Beatrice Formation did not record bulk density and neutron data, however, those that did (mostly within the oil fields) exhibited a clear gas effect (Figure 5). Density/neutron logs recorded outside the oil fields also exhibited the gas effect in wells 11/29-1 and 12/26c-5. Evidence for the methane saturation of the Mains Formation is less pronounced, as beyond the oilfields, little attention was paid to the formation in the well logs. However, gas shows are recorded in wells 12/26c-5 and 12/27-1 with large gas effects recorded in 12/26c-5 and 11/29-1.

Based on the number of positive gas shows, the gas effect, and the large gas discovery we conclude that methane saturation of brine is highly probable in both the Mains and Beatrice formations of the Moray Firth basin.

2.2 Methane saturation calculation

To further constrain the methane saturation level of the saline formations within the sedimentary basin, we perform a comparison between the theoretical methane solubility at reservoir conditions and the gas produced during the lifetime of the Beatrice Field, divided by the volume of produced water. Theoretical data from Duan & Mao (2006) imply a methane solubility in brine at the conditions found in the Beatrice and Mains formations of the Moray Firth basin to be ~0.1 mol/kg. A similar figure of ~0.1 mol/kg is found in McGee et al. (1981).

The data and calculations for the Beatrice field are outlined in Table 1.

Table 1: Calculation of actual solubility of methane in Beatrice oil field

Produced Water Properties	*Figure*	*Unit*	*Notes*
Density of produced water	9.98E+02	kg/m3	Assuming 35000ppm chlorides and 80°C using online calculator (CSG Network, University of Michigan and NOAA, 2011)
Volume of produced water	1.27E+08	m3	(Oil & Gas Authority, 2017)
Mass of produced water	1.26E+11	kg	Volume of produced water × Mass of produced water
Methane Properties			
Volume methane produced	7.20E+08	m3	(Oil & Gas Authority, 2017)
Density of methane at 1.013 bar and 25C	6.57E-01	kg/m3	(Air Liquide, 2018)
Mass of methane produced	4.73E+08	kg	Volume methane produced × Density of methane at 1.013 bar and 25C
Molecular weight	1.60E+01	g/mol	(Air Liquide, 2018)
	1.60E-02	kg/mol	
Solubility Calculation			

Mols gas produced	2.95E+10	mol	Mass methane/molecular weight
Methane solubility in Beatrice field	2.33E-01	mol/kg	Mols gas produced/mass of produced water
	0.23	**mol/kg**	**to 2 significant figures**

As outlined in the calculations provided in Table 1, the theoretical solubility of methane under the conditions of the Beatrice field is 0.1 mol/kg. The calculated solubility using the total volume of produced gas divided by the total volume of produced water is 0.23 mol/kg. This is clearly above the level calculated, but within the same order of magnitude, which is to be expected given the uncertainties of the theoretical calculations. The figure of 0.23 mol/kg should be taken as a maximum as some of the gas produced may have been in a free gas state, hence the "gas effect" seen in the well logs. These calculations are indicative of methane saturation or over saturation of the formation waters within the Beatrice field.

The same approach was used to ascertain the theoretical and calculated methane saturation levels within the Jacky field as outlined in Table 2.

Table 2: Calculation of actual solubility of methane in Jacky oil field

Produced Water Properties	*Figure*	*Unit*	*Notes*
Density of produced water	9.95E+02	kg/m3	Assuming 35000ppm chlorides and 85°C using online calculator (CSG Network, University of Michigan and NOAA, 2011)
Volume of produced water	1.70E+06	m3	(Oil & Gas Authority, 2017)
Mass of produced water	1.69E+09	kg	Volume of produced water* Mass of produced water

Methane Properties			
Volume methane produced	2.48E+07	m3	(Oil & Gas Authority, 2017)
Density of methane at 1.013 bar and 25C	6.57E-01	kg/m3	(Air Liquide, 2018)
Mass of methane produced	1.63E+07	kg	Volume methane produced* Density of methane at 1.013 bar and 25C
Molecular weight	1.60E+01	g/mol	(Air Liquide, 2018)
	1.60E-02	kg/mol	
Solubility Calculation			
Mols gas produced	1.02E+09	mol	mass methane/molecular weight
Methane solubility in Jacky field	6.01E-01	mol/kg	mols gas produced/mass of produced water
	0.60	**mol/kg**	**to 2 significant figures**

Within the Jacky field, the theoretical solubility is 0.1 mol/kg and the calculated solubility is 0.60 mol/kg. This is three times higher than the Beatrice field but still within the same order of magnitude as both the calculated and theoretical solubilities. It is probable that more gas may have exsolved from the formation water in this part of the reservoir after several years of production due to the drop in reservoir pressure. This would cause free gas to flow towards the well increasing the gas to water ratio.

3. Material and methods

We performed an economic comparison of four scenarios: gas production only, electricity production from gas only, CO_2 storage only, and an "allin-one" system.

An assessment of the volume of water available was used to calculate the size of both the methane resource and the potential mass of CO_2 that could be stored. Using these estimates, an energy balance for each component of the system was calculated, allowing an estimate of the capital and operating costs over the lifetime of an "all-in-one" system to be determined.

A Monte Carlo simulation was used to produce frequency distributions for each of the four scenarios. Base equations used in all scenarios were calculated for the size of the water and methane resources, and expected production. Then the gas production, CO_2 storage, and "all-in-one" system scenarios were calculated.

Probability quantiles were calculated for each scenario where the first quantile represents the value where 75 % of results equalled or exceeded that value. The second quantile represents the value where 50 % of results equalled or exceeded that value, which is the same as the mean value and referred to as such from here on. The third quantile represents the value where 25 % of results equalled or exceeded that value.

3.1 ASSESSING THE SIZE OF THE RESOURCE

Essential to the scenario calculations are ranges of values for the size of the water and methane resources, and expected production. The volume of water in the Mains formation was calculated by combining data from the literature (Richards *et al.*, 1993) and well logs. The areal extent of the Mains formation was taken from the Scottish Centre for Carbon Storage (2009) report. The formation is of variable thickness as observed in well logs but minimum and maximum values are provided by Richards et al. (1993). These were used and an even distribution across the areal extent of the formation was assumed due to a lack of further data.

The majority of the available porosity data for the Mains formation is from measurement of samples obtained from the Beatrice field, which has an average value of 15 %. Outside of the field, well 12/27-1 exhibits a higher average porosity of 23 %. The porosity of the Mains formation within the Beatrice oilfield was used with a normal distribution. Based on the findings of Haszeldine et al. (1984), extrapolating reservoir quality outside of the oilfields was justifiable as there was no evidence that porosity was related to oil charge.

The net:gross was calculated from well logs and combined with evidence from Richards et al. (1993). A maximum and minimum value with even distribution was used as a model input using this data. This reflects the different proportions of mud and sand in different parts of the formation.

Water density values were used for brine with a salinity of 35000 ppm and temperatures of between 75 °C and 95 °C to account for changes in depth across the formation. The methane solubility in the Beatrice formation and Mains formation brines was calculated using the literature figure from Duan & Mao (2006) of ~0.1 mol/kg, and the figure calculated from Oil & Gas Authority (2017) data from the Beatrice field of 0.23 mol/kg. The error of methane solubility was calculated to be +/- 0.05 mol/kg.

The Jacky field had a much higher calculated figure (0.60 mol/kg) than that of Beatrice. This could be accounted by the fact that the field only produced for a short time compared to Beatrice (causing more degassing per unit of water produced), the field only produced from the top sand of the Beatrice Formation, or that there was a significant gas:oil ratio in that field. Hence, this higher value was not considered for the total methane volume calculation as it is likely to be higher than the true value.

The molar volume of an ideal gas at standard temperature and pressure was used to ascertain the volume of produced gas at the surface. The following equation gives the potential size of the methane resource in the Mains formation:

$$A \times h \times \phi \times NtG \times \rho_{brine} \times sol_{CH4} \times 0.0224\ m^3 \quad [1]$$

Where *A* is areal extent of the Mains formation, *h* is the thickness of the Mains formation, ϕ is the porosity of the Mains formation, *NtG* is the net:gross ratio of sand to mud in the Mains formation, ρ_{brine} is the density of the formation brine, sol_{CH4} is the solubility of methane in brine, and 0.0224 m^3 is the molar volume of ideal gas at STP.

Using these water volume and methane solubility calculations a range of values for methane per m^3 formation water could be determined.

3.2 Daily well production

Production data from the Jacky oilfield (Oil & Gas Authority, 2017) was used to calculate a range of figures for daily water production per well. Jacky was used for two reasons, as it produced from an over pressured section of the basin and possessed only one production well, as opposed to the more than thirty present in the Beatrice field. The total production of liquids (oil and water) were divided by the number of days of production over the field's lifetime. The Jacky field has produced between 1300 and 1600 m^3 of brine and oil per day in the first two years of its operation (Oil & Gas Authority 2017)

3.3 Gas Production Scenario

The well production and dissolved methane concentration values were used to produce values for gas production volumes per m^3 brine. This was then converted into monetary terms via conversion to kWh. Gross monetary value was calculated using the real cost of wholesale gas in the UK corrected to April 2017 prices using data from Ofgem (2017b) and The Office for National Statistics (2017). The maximum and minimum gas prices from the 2010-2017 period were used under the assumption that gas prices over the next decade will be similar.

Known per barrel cost of oil production from the Jacky field (Edison Investment Research, 2009) was converted to a per m^3 figure for total produced liquids (both oil and water) and subtracted to give a net monetary value. Combining this cost with the amount of gas produced per m^3 of water provided the cost per m^3 gas. It is worth noting that this price per barrel figure is for oil and takes into account the exploration, development, and production costs. It is extremely likely that these will be considerably lower for a brine production system using existing infrastructure, but we use the oil production cost figure is used due to a lack of other available cost estimates.

3.4 Electricity Production Scenario

Assumption of complete combustion of methane in a modern CCGT (combined cycle gas turbine) with an efficiency of 58.3 % (Aminov *et al.*, 2016) was used to calculate electricity production:

$$kWh_{gas}m_{-3brine} \times e_{CCGT} \qquad [2]$$

Where $kWh_{gas}m^{-3}{}_{brine}$ is the energy equivalent of gas per cubic metre of brine, and e_{CCGT} is the efficiency of a CCGT.

In monetary terms we can calculate what this power generation is worth using an inflation adjusted average price for electricity from wholesale electricity price data from Ofgem (2017) and historic consumer price index data from the Office for National Statistics (2017). As previously, the maximum and minimum electricity prices from the 2010-2017 period were used under the assumption that electricity prices over the next decade will not be significantly lower or higher.

3.4.1 CO_2 Volume

The potential storage volume of CO_2 dissolved in brine in the Beatrice oilfield was calculated using the production volumes of oil from the field along with the formation volume factor and CO_2 solubility data from Rochelle & Moore (2002) and Bando et al. (2003). This assumes that the produced oil can be replaced entirely by CO_2 saturated water.

$$\rho_{brine} \times M(CO_2) \times sol_{CO2} \times V \qquad [3]$$

Where ρ_{brine} is the brine density, $M(CO_2)$ is the molar mass of CO_2, sol_{CO2} is the CO_2 solubility in brine, and V is the volume of water in the Mains formation.

The storage capacity of the Mains formation is considered to be the amount of CO_2 that can be dissolved in the total volume of formation water. This assumes that as water is produced and reinjected the pressure within the formation does not change.

However, a more realistic scenario is to calculate the amount of CO_2 storage per m^3 of formation water as not all water is likely to be accessible:

$$\rho_{brine} \times M(CO_2) \times sol_{CO2} \qquad [4]$$

Where ρ_{brine} is the brine density, $M(CO_2)$ is the molar mass of CO_2, and sol_{CO2} is the CO_2 solubility in brine.

This figure can then be used to ascertain the amount of extra space available for additional CO_2 in the full closed-loop system.

3.4.2 Injection Costs

In order to inject water into the subsurface the bottom-hole pressure needs to be greater than the reservoir pressure, with a maximum pressure gradient of 0.5 psi/ft as recommended in Bradley (1987). The injection wellhead pressure must take this into account.

A range of injection pressures between ~1.1 and ~22 MPa were used. These were calculated as the bottomhole pressure minus hydrostatic and atmospheric pressure (assuming produced brine will be brought to atmospheric pressure to exsolve the methane). These two figures cover the minimum injection pressure required for the Beatrice field and those required for pressure maintenance within the Mains formation. It is also assumed that CO_2 will dissolve at these pressures as they are within the ranges given in Eke *et al.* (2011).

Assuming a pump efficiency of 0.8 (Ganjdanesh and Hosseini, 2016) a pump energy requirement equation is used. In this case using a modified equation for shaftpower (P_h):

P [redacted]

η_{pump}

Where ρ is the brine density, g is acceleration due to gravity, P_{mixing} is the mixing pressure, SG is the specific gravity of the brine and η_{pump} is the pump efficiency.

3.5 Full closed-loop system with Geothermal and Capture Scenario

3.5.1 Carbon capture cost

The mass of brine required to provide enough energy to capture 1 kg of CO_2 can be calculated using the following assumptions: (i) That the ammonia capture process captures 90% of carbon dioxide from methane combustion (Gazzani, Sutter and Mazzotti, 2014). (ii) Using the chilled ammonia process as the maximum and the ammonia with organic solvent process as the minimum energy requirement. (iii) The Ammonia regeneration temperature is less than 70°C (Novek *et al.*, 2016). As we assume complete combustion of methane, there is a 1:1 ratio of mols methane to mols CO_2 and therefore we can use the methane volume per m^3 brine in the equation, corrected for 90 % capture efficiency:

$$V_{gas}m^{-3}{}_{brine} \times \rho_{CO2} \times E_{amm.} \times \eta_{cap.} \quad [6]$$

Where $V_{gas}m^{-3}{}_{brine}$ is the volume of gas per cubic metre of brine, ρ_{CO2} is the CO_2 density, $E_{amm.}$ is the ammonia carbon capture cost, and $\eta_{cap.}$ is the capture efficiency.

Table 3: A comparison of the two chilled ammonia carbon capture processes, their energy requirements, and the equivalent mass of brine required to provide the required geothermal energy at different brine temperatures. Masses were calculated from the data in Table 4.

Process	**Energy cost MJ/kg** CO_2	**kg brine required at 60 °C**	**kg brine required at 70 °C**	**kg brine required at 80 °C**	**kg brine required at 90 °C**	**Source**
Chilled Ammonia	2.43	120.2	100.0	85.6	74.7	(Sutter, Gazzani and Mazzotti, 2016)
Ammonia + organic solvent	1.39	68.7	57.2	49.0	42.8	(Novek *et al.*, 2016)

3.5.2 Geothermal energy

Using the geothermal gradients calculated by Argent et al. (2002) for wells 21/23-1 and 12/24-2 of 29.7 °C/km and 32.4 °C/km respectively (both +6 °C for average sea bottom temperature) we find that the lowest temperature for the Mains formation is in well 11/30aA18 at 65 °C. The maximum temperature is found in well 11/25-1 where the base of the Mains formation would be 110 °C at the higher gradient. Assuming an error margin of ±5 °C, the minimum and maximum used are 60 °C and 115 °C respectively. The 115 °C value was extrapolated from a graph of the existing data up to 110 °C from Clarke & Glew (1985). Using the energy calculations in Table 4 we can calculate the geothermal energy per unit volume in the brine:

$$kWh_{therm.}\,kg^{-1}{}_{brine} \times \rho_{brine} \qquad [7]$$

Where $kWh_{therm.}\,kg^{-1}{}_{brine}$ is the geothermal energy per kg of brine, and ρ_{brine} is the brine density.

Table 4: Energy release from cooling hot brine (35000ppm) to 10 °C; calculated from Clarke & Glew (1985). The value for 115 °C was extrapolated from the rest of the data.

Molality	Initial temp. /°C	specific heat capacity j/kg.k	change in temp/K or C	mass /kg	energy released/j	energy released/MJ (2 significant figures)
0.6	60	4044.3	50	1	202217	0.20
0.6	70	4049.1	60	1	242944.2	0.24
0.6	80	4055.4	70	1	283878	0.28
0.6	90	4063.6	80	1	325089.6	0.33
0.6	100	4073.9	90	1	366647.4	0.37
0.6	110	4088.8	100	1	408877	0.41
0.6	115	-	105	1	413900	0.41

3.5.3 Calculating Net energy balance

The net energy balance can then be calculated per m^3 brine using methane production, combustion, geothermal energy extraction, carbon capture, CO_2 dissolution into the brine, and reinjection.

$$((kWh_{gas}m^{-3}{}_{brine} \times e_{CCGT}) + kWh_{therm.}\,kg^{-1}{}_{brine}) - (E_{amm.} + P_h) \quad [8]$$

Where $kWh_{gas}m^{-3}{}_{brine}$ is the energy equivalent of gas per cubic metre of brine, e_{CCGT} is the efficiency of a CCGT, $kWh_{therm.}\,kg^{-1}{}_{brine}$ is the geothermal energy per kg of brine, $E_{amm.}$ is the ammonia carbon capture cost, and P_h is the injection energy (shaftpower).

The net energy balance can then be assigned a monetary value using the inflation adjusted average price for electricity.

3.5.4 CAPEX and OPEX Costs

No reliable figures are available for individual wells but the consensus in the literature is that drilling and completing a North Sea oil well costs upwards of £10 million. One 2014 opinion piece stated a cost of between £15 and £40 million (MacDonald, 2014).

In this study it is assumed that the per barrel production cost from Edison Investment Research (2009) includes the drilling of the wells at the Jacky site as well as the OPEX of the production platforms.

CCGT units cost around £10 million for a 17.3 MW model (Welander, 2000). Estimates of the cost of a post combustion capture system for gas range from a low(p80) of 813 $£_{2013}$/kW to a high(p20) 964 $£_{2013}$/kW (DECC and Mott MacDonald, 2012) (£885.45 and £1,049.91 in 2017 money). Hence, CO_2 capture costs from a 17.2 MW CCGT that equate to between 15.2 and 17.2 £million (2017 monetary values).

4. Results

All values are given to 2 significant figures

Total gas resource in Mains formation:

	Min	1st Quantile	Median	Mean	3rd Quantile	Max
TWh gas in Mains formation	3.7	68	120	155	210	1000

Gas scenario:

	Min	1st Quantile	Median	Mean	3rd Quantile	Max
Gas production per m^3 water (kWh)	9.5	19	29	29	38	48
Gross sale value gas per m^3 water (£)	0.096	0.35	0.54	0.59	0.78	1.5
Net sale value gas per m^3 water inc. production costs (£)	-2.7	-2.5	-2.3	-2.2	-2.0	-1.3

Electricity scenario:

	Min	1st Quantile	Median	Mean	3rd Quantile	Max
Electricity generation per m^3 water (kWh)	4.8	11	16	16	21	29
Gross value electricity per m^3 water (£)	0.17	0.52	0.78	0.82	1.1	1.9
Net value electricity per m^3 water inc. production costs (£)	-2.1	-1.7	-1.5	-1.4	-1.2	-0.33

CO_2 *storage scenario:*

	Min	1st Quantile	Median	Mean	3rd Quantile	Max

CO_2 storage potential per m3 water (kg)	61	68	74	74	81	88
CO_2 produced from gas combustion per m^3 water (kg)	1.9	3.8	5.6	5.6	7.5	9.4
CO_2 "extra space" per m^3 water (kg)	52	62	69	69	75	86
extra space sale value per m^3 water (£)	0.052	0.10	0.14	0.14	0.17	0.25
Mains formation total dissolved CO_2 storage capacity (kg)	2.4E+10	2.1E+11	3.5E+11	4.0E+11	5.4E+11	2.0E+12
Beatrice oilfield dissolved CO_2 storage capacity (kg)	1.8E+09	2.0E+09	2.2E+09	2.2E+09	2.4E+09	2.6E+09

Full system:

	Min	**1st Quantile**	**Median**	**Mean**	**3rd Quantile**	**Max**
Thermal energy per m^3 water (kWh)	56	70	85	85	100	110
"All-in-one" system energy balance per m^3 water (kWh)	53	79	94	94	110	140
"All-in-one" system energy balance sale	-0.34	1.6	2. 5	2.6	3.5	6. 9

value per m^3 water inc. prod costs (£)						

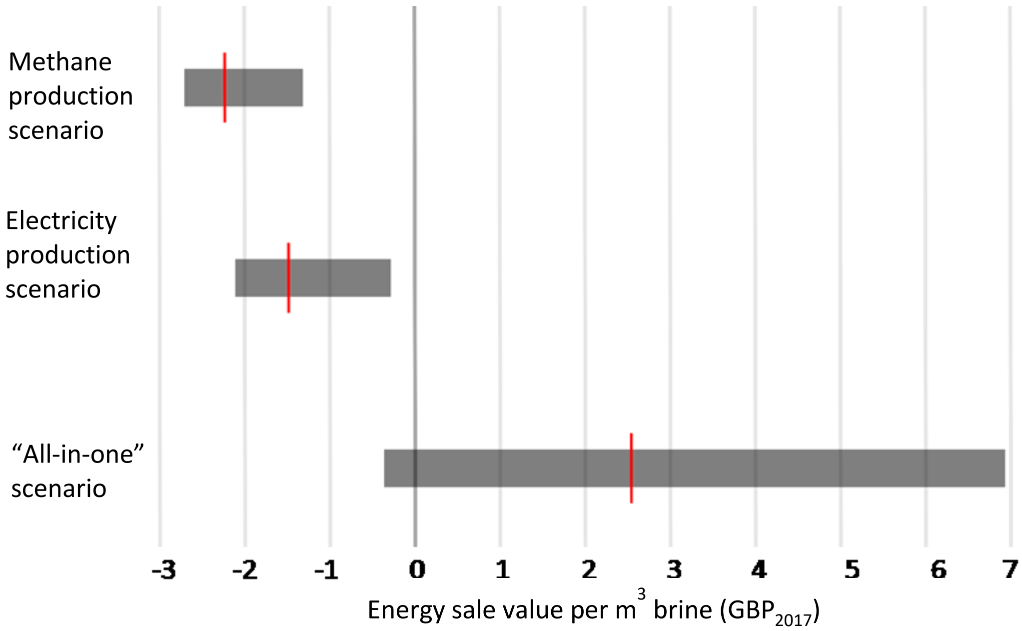

Figure 6: Comparison of energy sale values per m^3 brine (GBP$_{2017}$) for three different scenarios. Red lines indicate P50 values.

5. Discussion

The size of the resource is significant when compared to yearly energy consumption in the UK. Our calculations show that the total gas resource ranges from between 3.7 TWh and 1000 TWh. The total UK gas demand for 2017 was ~875 TWh (Halliwell and Lucking, 2017). The mean resource was calculated as 155 TWh which would cover ~18 % of this assuming similar levels of demand in future years.

However, the gas production scenario calculation suggests that the brine gas resource is not commercially viable on its own. Overall losses are somewhere between £2.7/m^3 and £1.3/m^3 (Figure 6). At the flow rates predicted for the system based on the Jacky field production history, losses would be up to £4,336 per well per day. Similarly the electricity production scenario also leads to losses of between £2.1/m^3 and £0.33/m^3 (Figure 6) which would equate to a maximum loss per well per day of £3,328.

Once the full system is considered, the geothermal energy contributes enough to shift the energy balance into the positive, however the minimum monetary value per m^3 is still negative at a loss of £0.34/m^3 but could provide a maximum income of £6.9/m^3 under the most favourable conditions (Figure 6). Overall, this equates to a maximum loss of £544 per well per day or a maximum profit of £11,008 per well per day. Hence, the "all-in-one" system is very likely to break even and be able to cover its own energy requirements.

The difference between the storage potential for dissolved CO_2 and the amount generated within the system is an order of magnitude. The generated CO_2 only accounts for between ~3 and ~10 % of the available storage space. This opens up such a scheme to disposal of externally produced CO_2, which given the EU emissions trading scheme carbon price could also be monetised.

Furthermore, the case study area selected is not ideal. It is not the onshore deep, hot (>100°C), overpressured aquifers considered by Ganjdanesh *et al.* (2014). As this study shows that the scheme is likely to be viable in a sub-optimal location, other locations with higher pressure regimes and hotter aquifers have the potential to generate significant profit.

This study has shown that the reuse of existing infrastructure to generate a self-sustaining CO_2 disposal site is worth serious consideration. The North Sea contains a significant amount of infrastructure earmarked for decommissioning, but re-use could be the key to overcoming the financial barriers to creating a large-scale carbon storage industry.

The Mains formation capacity estimate is somewhat uncertain as it is based on estimated volumes, however the capacity estimate for the depleted Beatrice field is much higher confidence due to accurate production figures. The Beatrice field has the potential to store between 18 and 26 Mt (megatonnes) of CO_2 without the risk of leakage as the CO_2 saturated brine is denser than the native brine and will tend to sink, unlike supercritical CO_2 that remains buoyant in the subsurface.

Recent work has illustrated that production of brine from a North Sea saline formation can significantly increase the potential storage capacity of the Captain sandstone formation and assist in pressure management during the lifetime of the site (Jin *et al.*, 2012). Our study has shown that so the addition of gas and geothermal energy production could help to reduce running costs during brine production operations. Economies of scale could be introduced where several platforms could feed gas to a central power generation hub. As the only necessities for an “all-in-one” system are a depleted, underpressured field and an overpressured aquifer there are many other potential options available in the UK North Sea currently available through the use of existing infrastructure.

6. Conclusions

The size of the methane saturated brine resource in the Mains formation is significant when compared to UK gas demand. Yet production of brine gas from the Mains formation is unlikely to be commercially viable, even if used to generate and sell electricity.

However, if brine is being produced for pressure management or for dissolution CO_2 storage, then electricity generation can provide some of the energy requirements for running the system. Producing geothermal energy alongside the gas with electricity production can cover the energy costs of a closed loop dissolved carbon storage facility offshore with its own carbon capture unit. Hence, the "all-in-one" system has the potential to become self-sustaining in terms of energy balance.

Furthermore, the likely amounts of produced CO_2 from the "all-in-one" system would not fully saturate the produced brine. This opens the potential of importing CO_2 from external sources for storage. This could provide additional income depending on the carbon price and help overcome financial barriers for new carbon storage sites.

Hence, we find that a viable system could build upon existing infrastructure in the UK North Sea, a mature basin with large numbers of platforms and depleted fields suitable for an "all-in-one" approach. This would be less expensive than current plans to decommission all UK North

Sea infrastructure and could help to open up the UK North Sea to a world leading large-scale carbon storage industry.

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