Open or Closed: A Discussion of the Mistaken Assumptions in the Economides Analysis of Carbon Sequestration

A. J. Cavanagh[1], R. S. Haszeldine[2] and M. J. Blunt[3]

1) The Permedia Research Group, Ottawa, Canada
2) SCCS, School of GeoSciences, University of Edinburgh, UK
3) Department of Earth Science and Engineering, Imperial College London, UK

Abstract
The proposition by Economides and Ehlig-Economides (E&E) in 2009 and 2010 that geological storage of CO_2 is 'not feasible at any cost' deserves to be examined closely, as this is counter to the view expressed in the overwhelming majority of geological and engineering publications (e.g. IPCC, 2005; IEAGHG, 2009**;** Qi *et al.,* 2009). The E&E papers misrepresent this work and suggest that: 1) CO_2 cannot be stored in reservoirs that have a surface outcrop; 2) CO_2 storage capacity in reservoirs without outcrops has been over-estimated and 3) the potential for CO_2 storage in the deep subsurface is miniscule. We take issue with each of these, discussed in turn below. We also 4) review the evidence to date, which contradicts the Economides' analysis, and 5) describe common pressure management strategies that demonstrate a more realistic and rational assessment of the experience of CO_2 injection to date. We conclude that large-scale geological CO_2 storage is feasible.

Bumblebee Analogy
Modern technological folklore has created several popular myths and mistaken analyses. A good example of this is the mathematical 'proof' that bumblebees are unable to fly. The analysis was, within its own assumptions, correct. However, the assumptions were incorrect as they were based on a faulty mathematical analogy between bees and conventional fixed-wing aircraft. A helicopter comparison is more appropriate, as it includes analysis of the lift generated by turbulence (Peterson, 2004). The general point here is that scientific analogies can be drawn that are too simplistic and misleading, even if mathematically rigorous. An accurate framing of the initial problem is of vital importance. Consequently, numerical simulations can appear to support a false proposition when the approach is founded on a flawed conceptual model. We suggest that E&E have made a comparable mistake.

1) Outcropping reservoirs. E&E state that all potential reservoirs with exposures at the land surface can be discounted from a CO_2 storage analysis because of the possibility of CO_2 leakage. However, reservoirs with outcrop exposures at the surface can, and do, host hydrocarbon accumulations deeper down-dip. A simple example is the hydrocarbon stratigraphy of Alberta basin, which hosts abundant oil and gas down-dip to the west of exposed sandstones, despite a weak regional water drive to the east that has been flowing for millions of years (Garven, 1989). Additional well-known examples include the vast hydrocarbon volumes trapped in the porous and permeable reservoirs of Texas (e.g. the Smackover Formation) down-dip of their surface outcrop (Moore and Druckman, 1981), and also the giant Gröningen gas accumulation of the Netherlands (Stauble and Milius. 1970; Whaley, 2009), which hosts abundant methane gas down-dip of the Rotliegend sandstone outcrop over much of western Europe. Water movement occurs over hundreds of kilometres in sedimentary basins (Sverjensky and Garven, 1992) but this does not prevent hydrocarbons from trapping (Rich, 1921).

2) Available pore space. E&E are correct in highlighting pressure as one of the limits on CO_2 injection, although pressure is only one of several important factors. However, they are not correct in claiming as a 'discovery' the implication that the volume available to injected CO_2 is only "1%" of the reservoir pore volume. Similar early approximations date back over a decade (e.g. van der Meer, 1995). All published estimates of such storage coefficients have been recently reviewed and a range of values identified (CSLF, 2008; USDOE, 2008; IEAGHG, 2009) by means of comprehensive numerical simulations. For instance, the USDOE (2008) determined via Monte Carlo analysis that the realistic range for likely geological settings is between 1% and 4% for a 15-to-85% confidence interval, giving an average 2.4% efficiency for 50% confidence. The range used in regional assessments of storage capacity is typically 0.2% to 4%, while many recent evaluations use 1% or 2% of the pore volume (SCCS, 2009; IEAGHG, 2009). The "1%" analysis is neither news, nor an accurate reflection of the more considered estimates that both encompass and predate what is essentially a crude approximation by E&E.

The total volume of capacity available for storage remains the subject of research in the USA and other countries around the world (GCCSI, 2009). There is little disagreement about the two principal types of resource that qualify: a) depleted hydrocarbon fields, which are well understood, with depressurised gas fields forming particularly attractive early targets; and b) saline formations, which are agreed to hold the most potential. The current uncertainty is considered to be how to assess the commercially useful volume, which is likely to be less than the optimistic "1%" first approximation described above. The key point is that the existing analyses of capacity as a fraction of a percentage of the formation volume for all regional assessments still provide predictions of extremely large storage volumes in Europe (GeoCapacity, 2009), in North America (USDOE, 2008), and in Australia (CO2CRC, 2008).

3) Numerical model. E&E present example calculations that make several highly questionable and poorly justified numerical assumptions. In our view, the assumptions entirely invalidate the calculations. Four key aspects of the E&E model (storage boundaries, reservoir properties, heuristic approximations, and geological setting) are discussed below:

- Firstly, the storage reservoir is assumed to be closed, with no-flow boundaries. This simplification is inappropriate for regional CO_2 storage modeling, as it is well understood that the shales that typically surround storage reservoirs have non-zero permeabilities (Yang and Aplin, 2009). The regional flow attributes of aqueous and hydrocarbon fluids through and across such porous and permeable media has been understood now for many decades (e.g. Lamb, 1932; Hubbert, 1957), and it is widely accepted that the no-flow approximation is only a good approximation for reservoir engineers working at a small scale when wishing to examine natural gas field production, or methane gas engineered storage and recovery (Dake 1978, Cavanagh, 2010). Although the boundary shales that trap oil and gas are effectively perfect seals for multi-phase flow, for large CO_2 operations, the regional-scale is significant. This includes consideration of single-phase pressure footprints and the flow of water through the low permeability shale boundaries, and shifts the emphasis to an open single-phase pore-water displacement model (Zhou et al., 2008), where the pressure change and rate of pressure variation are significant. Therefore, any subsurface formation, including those chosen for CO_2 storage is unlikely to have a zero-flow boundary. Such a caricature of a natural rock body is naïve at a regional scale.

- Secondly, the reservoir is assumed to have an average permeability of 100 millidarcies and an average thickness of approximately 30 meters. Although these values exist in deeply buried reservoirs, they are unrepresentative of many hydrocarbon reservoirs or saline formations, which frequently have permeabilities of many hundreds of millidarcies and thicknesses of hundreds of metres. The CO_2 'Best Practise' storage manual (Holloway et al., 2004) provides more appropriate and realistic guidance. The pessimistic parameter values chosen by E&E inevitably produce pessimistic calculations of capacity.

- Thirdly, confidence in the rigour of the analysis is undermined by a number of basic mistakes. For example, unrealistic values are chosen for the heuristic that represents the temperature gradient (18°C/km instead of a more typical 35°C/km), and the pressure gradient term is far too simple, ignoring both the atmospheric pressure contribution and salinity of the pore fluid. Perhaps more significantly, a constant of proportionality in the pressure equation for the 2009 paper reappears as ten times its approximate reciprocal value in the 2010 paper (i.e. the value '141.2' in equation [8] of the first paper becomes '0.069' in the same equation of the second paper). This is perhaps the reason why the 2010 abstract reduces the predicted reservoir volume required for storage by a factor of ten compared to the earlier 2009 paper (i.e. "50 to 200" becomes "5 to 20" in the second abstract). Surprisingly, the results, interpretation and discussion remain unaltered despite this order-of-magnitude change in the analysis. Such elementary errors and inconsistency in methodology do not inspire confidence.

- Fourthly, the calculation makes an explict assumption that only a single 30 meter thick sandstone exists regionally beneath the ground surface that is to be used as a storage location. This is, again, extremely naïve. For example, any familiarity with the iconic images of the Grand Canyon will readily communicate that the subsurface can, and often does, contain many packages of porous sandstone and carbonate that are many hundreds of metres in thickness, and really extremely widespread. Hydrocarbon basins such as the Illinois Basin (Swezey, 2009), Texas Gulf (Chowdhury and Turco, 2009), or the North Sea (Glennie, 1998) are also endowed with multiple layers of sandstone and each layer may be hundreds of metres in thickness. To imply that only one thin reservoir is available or viable for CO_2 storage, and that this consequently must extend regionally for thousands of square kilometers is simply untrue: a misrepresentation in light of established geological fact.

4) Evidence to date. Since 1996, three megatonne-per-year CO_2 storage projects have been undertaken (Sleipner, In Salah and Weyburn), injecting CO_2 into the deep subsurface accompanied by detailed scientific monitoring. The E&E papers comment that the most well-publicised of these, the Sleipner project, has stored less CO_2 radially than measured by seismic reflection, that significant leakage has occurred and that no pressure profile has been modelled. These are incorrect and unsupported assertions as shown by the detailed analyses of Arts *et al.* (2005) and Chadwick *et al.* (2009), and our own work (Cavanagh and Haszeldine, in review). No leakage from the storage reservoir has been detected or inferred. The pressure of injection has been measured at the wellhead since injection started in 1996, and no systematic pressure increase has occurred (Ringrose, 2010). This is entirely compatible with the consensus view that the Sleipner storage site is behaving as a large and effective reservoir for the storage of CO_2.

We have analysed the results of twenty CO_2 injection projects globally (SCCS, 2010). Of these, nine are at, or are intended to be at, an industrial scale, storing 1-to-130 Mt CO_2 during the project lifetime. Only the Midwest Regional Carbon Sequestration Partnership project at the Burger Plant, Shadyside, Ohio, has experienced severe pressure problems (USDOE, 2009; MRCSP, 2010), with a pressure build-up from 800-to-5400 psi (5-to-37 MPa) over 3hr 45 min. The Shadyside project was cancelled in 2008 after only a few tens of tonnes of the intended 3,000 tonnes CO_2 was injected. This is not surprising as the post-injection analysis showed the formation permeability to be extremely low at 0.001-to-0.08 millidarcies. By contrast, the storage sites at Snøhvit (450 mD), K12-B (20 mD) and In Salah (5 mD), have adequate permeability combined with thickness (i.e. injectivity) and are on schedule to store several millions tonnes of CO_2 injected at each site.

5) Pressure management. The E&E papers ignore the ability to engineer around the problem of increased subsurface pressure. It is well established in reservoir engineering that the greatest increase of pressure during injection is expected close to the well bore. Established methods can engineer to reduce this pressure build-up, for example, by increasing the length of contact between the well bore and the reservoir formation, typically by using horizontal drilling. A second method, water production, is often used to manage water breakthrough or increased pressure as a consequence of water injection during hydrocarbon production. This method produces formation water from the reservoir and either re-injects that into shallower reservoirs with high porosity and permeability, or if the environmental regulations allow, discharges to the surface. This use of relief wells to manage pressure is proposed at Gorgon (Flett *et al.*, 2009), and could be employed in the Utsira reservoir formation if required (Lindeberg *et al.*, 2009). This would allow a storage capacity of greater that "1%" to be achieved.

Discussion

From a review of current CO_2 injection and storage experiments, and a comparison of these with long-established models and concepts for hydrocarbon trapping and petroleum systems, it is apparent that subsurface reservoirs are not hermetically sealed, but instead are flanked by semi-permeable rocks such as shale. The permeability of these shale boundaries at the reservoir top, base and sides is low but, crucially, not zero. Accurate and appropriate three-dimensional fluid flow models of reservoirs can simulate the feedback effect of the permeability of the enclosing shale rocks on the pressure build-up inside the reservoir during CO_2 injection (Cavanagh, 2010). Results from our simulations of CO_2 injection show that a critical range of values exist for shale, which retain oil and gas as a seal. These are within the range of shale permeabilities measured globally by Yang and Aplin (2009). However if the enclosing permeabilities are one hundred times less, then insufficient fluid transmission occurs and the pressure increases significantly in the reservoir formation. Rocks with such low permeabilities appear to be rare in the subsurface at the depths envisaged for CO_2 storage, and are associated with deeply buried zones of naturally elevated geo-pressures. Such reservoirs are not prime candidates for CO_2 storage, and do not feature as abundant storage in global assessments, primarily because of the expense associated with drilling complex and deep wells. Therefore we are confident that CO_2 storage will not reflect the extreme cases chosen by van der Meer *et al.* (2006; 2008) or the E&E papers (2009; 2010) to illustrate a hypothetical but unfounded risk of pressure build-up.

Conclusion

In summary, we draw an analogy with the flawed mathematical models which concluded that bumblebees cannot, theoretically, fly. We have demonstrated that the Economides' analysis (2009 and 2010) is an overly simplistic calculation based on erroneous assumptions about subsurface geology and regional fluid flow in the sedimentary basins where CO_2 will be stored. Their open system analysis is flawed, and their closed system analysis is inappropriate. The assertion that CO_2 storage is "not feasible at any cost" is demonstrably untrue based on the results of worldwide injection experiments that are already successfully storing CO_2. While it is true that pressure build-up is one of many relevant factors which need to be taken into consideration when planning a storage site, this single factor is widely anticipated and well understood. Pressure build-up is certainly not a deal breaker for carbon capture and storage.

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