Natural Resources Research, Vol. 26, No. 2, April 2017 (© 2016)
DOI: 10.1007/s11053-016-9310-7

Review Paper

Cost Implications of Uncertainty in CO_2 Storage Resource Estimates: A Review

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Received 1 April 2016; accepted 15 August 2016
Published online: 30 August 2016

Carbon capture from stationary sources and geologic storage of carbon dioxide (CO_2) is an important option to include in strategies to mitigate greenhouse gas emissions. However, the potential costs of commercial-scale CO_2 storage are not well constrained, stemming from the inherent uncertainty in storage resource estimates coupled with a lack of detailed estimates of the infrastructure needed to access those resources. Storage resource estimates are highly dependent on storage efficiency values or storage coefficients, which are calculated based on ranges of uncertain geological and physical reservoir parameters. If dynamic factors (such as variability in storage efficiencies, pressure interference, and acceptable injection rates over time), reservoir pressure limitations, boundaries on migration of CO_2, consideration of closed or semi-closed saline reservoir systems, and other possible constraints on the technically accessible CO_2 storage resource (TASR) are accounted for, it is likely that only a fraction of the TASR could be available without incurring significant additional costs. Although storage resource estimates typically assume that any issues with pressure buildup due to CO_2 injection will be mitigated by reservoir pressure management, estimates of the costs of CO_2 storage generally do not include the costs of active pressure management. Production of saline waters (brines) could be essential to increasing the dynamic storage capacity of most reservoirs, but including the costs of this critical method of reservoir pressure management could increase current estimates of the costs of CO_2 storage by two times, or more. Even without considering the implications for reservoir pressure management, geologic uncertainty can significantly impact CO_2 storage capacities and costs, and contribute to uncertainty in carbon capture and storage (CCS) systems. Given the current state of available information and the scarcity of (data from) long-term commercial-scale CO_2 storage projects, decision makers may experience considerable difficulty in ascertaining the realistic potential, the likely costs, and the most beneficial pattern of deployment of CCS as an option to reduce CO_2 concentrations in the atmosphere.

KEY WORDS: Geologic CO_2 storage resources, Storage efficiency, Dynamic storage capacity, Cost uncertainty.

INTRODUCTION

In 2014, combustion of fossil fuels (coal, natural gas, and petroleum) accounted for about 82% of total primary energy consumption in the United States; renewable energy sources (including hydroelectric power, geothermal, solar, wind and biomass), about 10%; and nuclear (electric) power, about 8%. The International Energy Agency (IEA) estimated that the electricity and heat generation (power) sector combined with the industrial sector to account for about 61% of the world's carbon dioxide (CO_2)

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emissions in 2013, and these two sectors accounted for 50% of total U.S. emissions of CO_2 during the same year (IEA 2015a). The sources of CO_2 emissions in these two sectors are stationary, and it is feasible to capture and concentrate their emissions, transport the liquid CO_2 to a suitable geologic storage site, inject it deep underground into a geologic formation (a carbon sink), and isolate it from the atmosphere for hundreds to thousands of years, or even longer. This is a different scenario from the situation with diffuse and mobile sources of CO_2 in the transportation sector (ranked second to the power sector in terms of its share of global and U.S. CO_2 emissions), and implementation of carbon capture and storage (CCS) is far less feasible in that sector (U.S. Energy Information Administration 2015). Implementation of CCS for large stationary sources alone could make a substantial contribution to the mitigation of CO_2 emissions, while further development and attempts to better integrate alternative low- or zero-carbon energy sources proceed (IPCC 2005, 2014).

In addition to substantially increasing the share of renewables in the supply of primary energy or commercial deployment of CCS, the Intergovernmental Panel on Climate Change (IPCC) lists energy conservation, efficiency improvements, switching to less carbon-intensive fuels, nuclear power, enhancement of biological CO_2 sinks, and reduction of non-CO_2 greenhouse gas emissions (such as emissions of methane and nitrous oxide) as options that could be adopted to reduce concentrations of greenhouse gasses (GHGs) in the atmosphere. However, pursuing any of these options to an extent adequate to have a significant impact on climate change [on the order of reducing global CO_2 emissions by billions of metric tons (Gt) per year] would require costly economic, institutional, and societal changes. Including CCS as an option in a portfolio of feasible GHG-mitigation methods could reduce the costs of and increase flexibility in achieving desired stabilization of GHG concentrations in the atmosphere, and some climate-change goals may not be achievable without CCS (IPCC 2014). For CCS to be a viable option, sufficient geologic storage capacity to store large quantities of CO_2 permanently (in effect) will have to be made available at a cost that is competitive with that of the alternatives (IPCC 2005; Herzog 2011; IEA 2015b).

When comparing low- or zero-carbon energy alternatives, the total costs over the appropriate time horizon for each energy technology should be considered. Since the future is always uncertain and discounted at various rates, estimates of the future performance, costs, and potential liabilities that could be associated with the implementation of any new technology are difficult to compare (Herzog and Eide 2013). In general, CCS cost studies emphasize the high cost of (installing) carbon capture technology as the greatest barrier to widespread deployment of CCS (Rubin et al. 2013, 2015). Capture costs could dominate other costs of the CCS system, even after advances are made in capture technology. However, these studies are missing some potentially important components of CO_2 transportation and storage costs. Even recent estimates may only account for a fraction of what the realized CO_2 storage costs will be, because they do not include expected costs of active pressure management or other likely costs. In addition, transportation and storage costs could be underestimated if the inherent geologic heterogeneity of potential storage reservoirs is not considered. For example, geologic uncertainty could require more (costly) flexibility to be built into the CO_2 transportation (pipeline) network, and increased costs for site characterization in an attempt to resolve a greater amount of geologic uncertainty could have a significant impact on storage costs (Middleton and Bielicki 2009; McCoy and Rubin 2009; Eccles et al. 2012; Middleton et al. 2012a).

Many high-level (basin, national, and regional) CO_2 storage resource estimates exist which suggest that the technically accessible CO_2 storage resource (TASR) far exceeds most projections of aggregate demand for CO_2 storage capacity (Dooley 2013). Generally, these storage resource estimates are based on volumetric estimates of storage capacity, and do not include consideration of engineering issues, pressure buildup, risk, cost, time, or other potential constraints on utilization of the resource (Bachu 2015). These storage resource estimates are supposed to be constrained only by what is technically possible at the time of the assessment. The most important assumption in storage resource assessments (e.g., U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team (USGS) 2013) and other volumetric estimates of CO_2 storage capacity is that pressure buildup in the storage reservoir as a result of CO_2 injection will be mitigated by active pressure management, including by extraction of formation fluids (such as saline waters) (Heidug 2013). However, CO_2 storage cost estimates do not account for the costs of extracting, processing, and disposing of formation fluids to make way for injected CO_2. That is, estimates of CO_2 storage costs generally assume that the entire estimated storage resource is available, without including the costs for the pressure management that will probably be necessary to make a majority of that resource available. In this way, volumetric estimates of storage resources could be misleading without considering this important constraint (International Energy Agency Greenhouse Gas R&D Programme (IEAGHG) 2014).

Dooley (2011) and others (e.g., Popova et al. 2012; IEA 2015b) suggest that high-level assessments of the TASR have value in providing information about the prospective role that CCS could play as an option for mitigating CO_2 emissions over the long term in many countries and regions, and that this information could help decision makers in both the public and private sectors regarding whether or not to pursue and further develop CCS (projects) in those regions. This could be a valid use of the valuable information that high-level CO_2 storage resource assessments provide. However, decision makers should not place too much confidence in cost estimates for long-term CO_2 storage that are based on the estimates of theoretically available storage capacities (Bradshaw et al. 2007). Extensive data from many commercial-scale CO_2 storage projects and basin-level or smaller studies will be necessary to significantly reduce the inherent geologic uncertainty, better estimate the rates at which CO_2 can be safely injected, provide some gage of how much pressure management will be necessary to allow storage formations to accommodate the expected (nearby) demand for storing CO_2, and more accurately estimate the costs of wide-scale deployment of CCS (Rubin et al. 2015). It will likely be necessary to have more estimates of contingent storage capacities for a variety of types of reservoirs, locations and constraints, the spatial distribution of that constrained capacity, the costs to access it (including additional transportation and other costs) and expand it (through brine production and other methods), and better mapping of key geological heterogeneities in potential storage reservoirs. Otherwise, policy- and other decision makers could be lacking potentially critical information to be able to ascertain the realistic potential, the likely costs, and the most beneficial pattern of deployment of CCS as an option to reduce CO_2 concentrations in the atmosphere.

CO_2 STORAGE RESOURCES

Classification of CO_2 storage resources in the literature is inconsistent, but definitions of the TASR

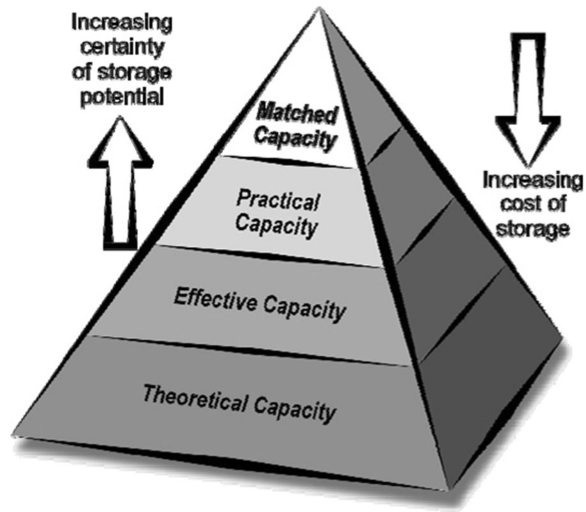

Figure 1. Techno-economic resource-reserve pyramid for CO_2 storage capacity in geological media within a jurisdiction or geographic region (copied from Bachu et al. 2007a, p. 13). The pyramid shows the relationship between theoretical, effective, practical, and matched capacities.

roughly correspond to a definition of theoretical storage capacity suggested by the Carbon Sequestration Leadership Forum (CSLF). In the CSLF categorization of CO_2 storage potential (Fig. 1), theoretical storage capacity is the most uncertain (CSLF 2005). Theoretical storage capacity is followed in the order of increasing certainty by effective storage capacity, which includes consideration of some engineering constraints in addition to just the pure geological considerations for theoretical capacity; practical storage capacity, which is a subset of effective capacity that considers some additional technical, legal and regulatory, infrastructure, and general economic limitations; and matched storage capacity, which is a subset of practical capacity that is obtained by detailed matching of large stationary CO_2 sources with geological storage sites that are adequate in terms of capacity, injectivity, and supply rate (Bachu et al. 2007a, b; Bradshaw et al. 2007). There is also an ongoing effort by the United Nations (UN) to apply the UN Framework Classification for Fossil Energy and Mineral Reserves and Resources to the geologic storage of CO_2 (Task Force on Application of UNFC-2009 to Injection Projects 2015).

Estimates of U.S. CO_2 Storage Capacity

Recent estimates of geologic CO_2 storage capacity for individual sites, geologic basins, countries, and regions were surveyed, compiled, and analyzed by Dooley (2013). He observed that a major difference in the recent estimates of CO_2 storage resources and those of the 1990s and early 2000s was the increasing share of the total storage capacity accounted for by potential storage in deep saline-filled formations (DSFs) relative to that in depleted (or in the process of being depleted) oil and gas reservoirs (DOGs). Storage of CO_2 in DOGs will rely primarily on buoyant trapping. In buoyant trapping, the CO_2 generally flows upward until it is immobilized in a stratigraphic or structural trap formed by the caprock, lateral seals, sealing faults, and/or other seals (Brennan et al. 2010). This is how the natural geologic trapping of oil and gas occurs. If hydrocarbons are still present in the storage reservoir, then the injected CO_2 can help increase recoveries [e.g., enhanced oil recovery (EOR) projects]. Production of hydrocarbons could provide revenues that would help offset CO_2 storage costs, while (at least partially) mitigating pressure constraints in buoyant structures (White and Foxall 2016). After many years of oil and gas exploration and production, there is generally less geologic uncertainty with respect to DOGs, and the costs and timeframe for monitoring and verifying CO_2 storage could be far less than in DSFs (IPCC 2005; Bachu 2015). However, the United States Geological Survey (USGS) estimated that buoyant storage accounts for only 2% of the mean TASR onshore in the United States (USGS 2013), and other high-level assessments also estimate that the potential storage capacity of DOGs accounts for a very small fraction of the total CO_2 storage capacity in the country (e.g., NETL 2012).

Depending on how many types of potential CO_2 storage sinks are considered, approximately 95–98% of the TASR in the United States could be located in DSFs (NETL 2012; USGS 2013). In these potentially extensive geologic formations, residual trapping is the most relevant mechanism for immobilizing CO_2. Solubility trapping may play an increasing role in the long run, but may not significantly add to current estimates of storage capacity (Bachu 2015). Residual trapping occurs when droplets of CO_2 are immobilized by capillary forces and remain trapped in the tight pore spaces of the rock as the plume of injected CO_2 passes through. This trapping mechanism does not rely on lateral seals, and is effective at sequestering CO_2 in *open* geologic systems (not laterally confined by impermeable seals or low-permeability zones) (Brennan et al. 2010). As the CO_2 occupies the pore space, however, it displaces in situ brines and other formation fluids. In an open DSF, the injected CO_2 and brines can migrate laterally over an extensive area, and possibly access a greater number of potential leakage conduits and cause changes in stress further afield than in a *closed* or *semi-closed* system (bordered laterally by impermeable seals or low-permeability zones, respectively) (Zhou et al. 2008). In an open system, CO_2 storage can create a pressure front that could extend for 100 km or more, given an areal extent of the CO_2 plume of only about 10 km (Pruess et al. 2003). In general, lateral migration and any pressure disturbances are more contained in a closed or semi-closed system, although the resulting pressure buildup could still be a major source of risk. Still, CO_2 storage in open DSFs could cost substantially more for monitoring and risk management, for a much longer time, and over a much greater area of review (AoR) than storage in buoyant traps.

In the USGS's national assessment of geologic CO_2 storage resources, their mean estimate for the total TASR onshore in the United States was about 3000 Gt of stored CO_2, of which buoyant trapping only accounted for about 44 Gt of the total CO_2 storage capacity. The remainder (about 2970 Gt of CO_2) was accounted for by residual trapping (USGS 2013). In the 4th edition of the U.S. carbon utilization and storage atlas (Atlas IV) by the National Energy Technology Laboratory (NETL) of the U.S. Department of Energy, their range for estimated total storage capacity in the United States was between about 1800 Gt CO_2 and 13,700 Gt CO_2, if one subtracts the estimated storage capacity located in Canada from the totals for North America given in Atlas IV. This wide range including a flat figure of about 120 Gt of CO_2 storage resource in oil and gas reservoirs and a range of between 52 Gt of CO_2 and 109 Gt of CO_2 that could be stored in currently unmineable coal seams (NETL 2012). In addition, the estimated CO_2 storage capacity in DSFs accounted for slightly greater than 96 and 93% of the (matched) storage capacity in the United States estimated by Dahowski et al. (2005) and (2011), respectively (Table 1).

In addition to storage capacity in DSFs accounting for a vast majority of the potential storage capacity in high-level estimates of geologic CO_2 storage resources, most of the variability in estimates of the total capacity can be attributed to uncertainty in the potential storage capacity in DSFs (Bachu 2015). For the United States, estimates of

Table 1. Some Estimates of Potential CO_2 Storage in the United States

Source of CO_2 Storage Resource or Capacity Estimate	National-Level Estimate of CO_2 Storage Resources	Mt. Simon Sandstone CO_2 Storage Capacity	Trapping Mechanisms	Storage Efficiency	Extraction of Formation Fluids
(Values in Gt CO_2)					
USGS (2013)	3000 (mean) (probability range: 2300–3700)	94 (mean)[a] (probability range: 62–130)	Buoyant and residual	Probabilistic, according to permeability	Yes (as necessary)
NETL (2012)	1800–13,700 (range[b] only)	11–150[a] (range[b] only)	Structural and hydrodynamic	According to lithology	Implicitly assumed
Szulczewski et al. (2012)	392 (migration-limited capacity)[c]	88 (migration-limited capacity)[a]	Residual and solubility	Formation specific	No
Dahowski et al. (2011)	2040	N/A	Structural and solubility	Generic	No
NETL (2008)	3600–12,900 (range[d] only)	27–109[a] (range[d] only)	Structural and hydrodynamic	Generic	Implicitly assumed
Dahowski et al. (2005)	2840	225	Structural and solubility	Generic	No
IPCC Special Report on CCS (2005)					
Gupta et al. (1999)	N/A	~270 (mean) range: 160–800	N/A	N/A	N/A
Bergman and Winter (1995)	5–500 (range only)	N/A	N/A	N/A	N/A
Winter and Bergman (1993)	98	N/A	N/A	N/A	N/A

[a] Only includes estimated CO_2 storage resources in the Illinois Basin portion of the formation
[b] Deterministic range reflects the 10–90% confidence interval used for estimates of storage capacity in DSFs
[c] Only for 11 DSFs; based on baseline migration-limited capacity estimates in Table S26 (Szulczewski et al. 2012)
[d] Deterministic range reflects the 15–85% confidence interval used for estimates of storage capacity in DSFs

CO_2 storage resources or capacity in DSFs have varied from just 5 Gt of CO_2 to on the order of tens of thousands of Gt of CO_2 (Szulczewski et al. 2012; Table 1). In Table 1, Gupta et al. (1999)'s estimated range of potential CO_2 storage capacity in one formation (Mount Simon Sandstone) exhibits significantly greater upper and lower bounds than Bergman and Winter (1995)'s estimated range of potential storage capacity for multiple DSFs in the entire United States suggests substantial uncertainty in estimates of storage capacity at the basin- and national-level, especially early on. Many comparisons of estimates like those in Table 1 have been done (e.g., Bachu 2008a, b; Spencer et al. 2011; Prelicz et al. 2012), and almost all have found similar contradictions and variability in the results of high-level assessments of CO_2 storage capacity. Literature cited by Heidug (2013) suggests that extremely high variability in the estimates of CO_2 storage resources and capacity (owing to differences in assumptions, methodologies, the areas and geologic formations included in the estimates, data, and other factors) could mean that the results cannot be accurately compared.

In Table 1, only the CO_2 storage capacity and resource estimates by NETL (2008, 2012) and the USGS (2013), respectively, meet the definitions of (estimates of) the TASR provided by Heidug (2013) or the USGS (2013). By this definition, the other storage capacity estimates in Table 1 should be significantly less than the TASR. The national-level estimates by Dahowski et al. (2005, 2011) in Table 1 consist of CO_2 storage capacity of potential geologic sinks that are matched with the nearest stationary CO_2 sources. If the above CSLF (2005) categorization applies to their results, it would imply that their estimates should be significantly less than the TASRs estimated by NETL (2008, 2012) and the USGS (2013). These estimates of Dahowski et al. (2005, 2011) are indeed less than the low end of the range of estimates by NETL (2008), but above that of the more recent NETL (2012) estimates. In addition, Dahowski et al. (2011)'s estimate of U.S. CO_2 storage capacity is somewhat below the probabilistic range of estimates by the USGS (2013), but that of Dahowski et al. (2005) is only about 5% less than the mean estimated TASR of the USGS (2013). That is, the estimates of Dahowski et al. (2005, 2011) are the same order of magnitude and comparable with the estimates of the TASR by NETL (2008, 2012) and the USGS (2013). This could be mostly owing to Dahowski et al. (2011)'s finding that sufficient abundance of CO_2 storage capacity is located within 270 km of 98% of the major stationary sources of CO_2 in the United States, such that almost all of the identified CO_2 storage resource could be matched with nearby sources of CO_2 in the country (Dahowski et al. 2011). Thus, their requirement of source-sink matching did not constrain their estimates of economically available storage capacity for major U.S. sources of CO_2 to be substantially lower than the estimates of the total TASR in Table 1.

Estimates of the storage capacity just in the Mount Simon Sandstone are listed for most of the sources in Table 1. The estimated storage capacities in the Mount Simon Sandstone in Table 1 range from on the order of tens of Gt of CO_2 to on the order of hundreds of Gt of CO_2. Despite estimating just migration-limited storage capacity, Szulczewski et al. (2012)'s estimate falls within the ranges of the total volumetric storage capacity estimated by NETL (2008, 2012) and the USGS (2013) for the Illinois Basin portion of the Mount Simon Sandstone. This could indicate that these four studies all considered a similar geographical area, and identified similar limiting factors (like a similar number of faults) within this portion of this potentially major storage formation. The older estimates of potential CO_2 storage in the Mount Simon Sandstone by Gupta et al. (1999) and Dahowski et al. (2005) are higher than the upper bounds of the ranges estimated by NETL (2008, 2012) and the USGS (2013). The storage capacity for the entire United States estimated in Dahowski et al. (2005) was revised downwards in Dahowski et al. (2011), but detailed information on the estimated capacity of just the Mount Simon Sandstone was not available in their latter study to be able to see if it might be closer to those of NETL (2008, 2012), Szulczewski et al. (2012), or the USGS (2013) (Table 1).

Geographical Areas and Formations Included in Estimates

The U.S. CO_2 storage resource estimates in Table 1 (first column) are all at a high-level (national-, regional-, or basin-scale), but the specific geographical areas and geological storage formations evaluated were not the same across studies. The two NETL carbon storage atlases (NETL 2008, 2012) covered the widest geographical area (including limited offshore resources) and number of geological formations (DOGs, DSFs, and unmineable coal seams). Dahowski et al. (2005, 2011) covered roughly the same types of formations as NETL, but only onshore for the 48 contiguous United States. In addition, Dahowski et al. (2005) were not able to incorporate data for several sedimentary basins in the mid-continent region of North America (including some in Colorado, Iowa, Kansas, and other states) into the DSF portion of their 2005 database. The USGS (2013) assessed potential geologic CO_2 storage onshore in the conterminous United States and Alaska (including state waters), but only estimated technically accessible storage resources in DOGs and DSFs. Szulczewski et al. (2012) just considered 11–13 (depending on the degree of aggregation) of the largest DSFs onshore in the United States at the basin level.

Data

Two estimates of potential CO_2 storage resources in the United States by Winter and Bergman (1993) and Bergman and Winter (1995) were included in the IPCC's special report on CCS (IPCC 2005). These estimates in the (early) 1990s are not comparable with the results of analyses even 10 years later. For their estimate of U.S. CO_2 storage capacity in DSFs, Bergman and Winter (1995) simply prorated a range of estimates of the possible global CO_2 storage capacity in DSFs according to the relative U.S.-global surface area covering the DSFs identified as potential sinks worldwide. Their preliminary estimate of storage capacity for this category of formations in the United States turned out to be almost four orders of magnitude lower than recent estimates. For estimating potential storage capacity in DOGs, Winter and Bergman (1993) had much more data and information as a result of oil and gas company interest in these structures, and their estimate of potential storage in DOGs in the United States is much more comparable with recent estimates, including being only about 18% less than the estimate by NETL (2012).

One of the most important factors that had changed between the estimation of potential storage capacity in U.S. DSFs by Bergman and Winter (1995) and by Szulczewski et al. (2012) was the size and sophistication of the available datasets used to generate estimates of CO_2 storage capacity. Szulczewski et al. (2012) determined model parameters either using publically available reservoir data directly, calculating parameters based on the data, or by estimation. The authors used reservoir data directly to determine the values of such parameters as depth, permeability, porosity, salinity, and thickness; calculated parameters included CO_2 viscosity and density, storage formation temperature, and fluid pressure; and estimated parameters included compressibility of the rocks in the targeted storage space and the caprock, connate water saturation, and residual CO_2 saturation. In general, studies that are more recent have likely benefitted from more and better geologic data, although Goodman et al. (2013) have suggested that data applicable to CO_2 storage in DSFs were still very sparse for many areas of the United States, even after 2010.

Variability in Methodologies

Given the many issues with comparing CO_2 storage capacity estimates, some recent studies have instead compared the assessment methodologies. This can allow better focus on the differences in scientific assumptions that might cause high variability in the results. A recent IEA report on CO_2 storage resource assessment methodologies (Heidug 2013) found that the treatment of geological uncertainty varied considerably, including between those for the assessments by NETL (2012) and the USGS (2013) in Table 1. The IEA report recommends that sources of uncertainty, methods of dealing with uncertainty, and significant constraints applied in assessment methodologies should be made very clear in CO_2 storage resource assessments.

Goodman et al. (2013) input a consistent subset of the data from most of the DSFs analyzed by Szulczewski et al. (2012) into the methodologies for the storage capacity estimates by NETL (2008, 2012), Szulczewski et al. (2012), and a preliminary methodology (Brennan et al. 2010) for the storage resource assessment by the USGS (2013), in order to better compare these methods for estimating CO_2 storage capacity. Goodman et al. (2013) found that the pairwise differences in estimated capacities were not statistically significant (at a 95% level of confidence). Based on their results, the authors concluded that uncertainty in the underlying geologic parameters could have a much greater impact on the estimates of CO_2 storage resources than differences in methodology. In NETL (2012) and Dahowski et al. (2011), the authors reported that the methodologies had been updated for these revisions of

NETL (2008) and Dahowski et al. (2005), respectively. However, the estimate of maximum CO_2 storage capacity in the United States and the range of capacity estimates increased significantly in the NETL (2012) revision, but the estimate of U.S. storage capacity decreased significantly in Dahowski et al. (2011)'s revision.

Seals and Trapping Mechanisms

With respect to seals, all of the assessment methodologies represented in Table 1 are consistent in their assumptions, except that the USGS (2013) required a regional seal over all buoyant structures, including DOGs. Although some buoyant (structural and stratigraphic) traps may be able to retain CO_2 at shallower depths, the USGS only assessed buoyant traps below 914 m, unlike in NETL (2008, 2012), Dahowski et al. (2005, 2011), and Winter and Bergman (1993) of Table 1, which included buoyant trapping at lesser depths. For estimating migration-limited storage capacity, Szulczewski et al. (2012) considered both residual and solubility trapping mechanisms, and the CO_2 had to be immobilized by those trapping mechanisms before reaching a boundary of the storage formation (such as an identified fault). Since the authors modeled the storage formation boundaries to be at least partially determined by such potential conduits for the CO_2 into the upper and lower strata, their estimates of migration-limited capacity could be interpreted as more constrained by a consideration of potential leakage and other risks. The other capacity estimates in Table 1 are not migration limited.

In Table 1, the capacity estimates of Dahowski et al. (2005) relied on solubility trapping, but their results are still comparable with those of the USGS (2013), which did not. Despite solubility trapping taking significantly longer to immobilize CO_2 than buoyant or residual trapping (Bradshaw et al. 2007), all of the volumetric estimates of CO_2 storage resources of the first six national-level estimates in Table 1 can be considered comparable with respect to the time dimension. This is because these are all estimates of the ultimately available pore volume far enough into the future as to be independent of time (Bachu 2015). Of the first six national-level estimates of CO_2 storage capacity listed in Table l, only the results of Szulczewski et al. (2012) appear to be well below the ranges of NETL (2008, 2012) or the USGS (2013). This could be mainly because Szulczewski et al. (2012) considered a smaller number and variety of potential CO_2 sinks over a smaller areal extent than the larger-scale assessments, and not as much because of differences in assumptions regarding trapping mechanisms (Goodman et al. 2013).

Common Assumptions

Since all of the CO_2 storage estimates in Table 1 are for the United States, they commonly exclude potential CO_2 storage capacity in (at least parts of) potential geologic storage formations that contained water with less than 1% (10,000 milligrams per liter) total dissolved solids. This common assumption is in agreement with U.S. Environmental Protection Agency regulations for the protection of drinking water (U.S. Environmental Protection Agency 2010). Other common criteria assumed by most of the sources of the storage estimates listed in Table 1 include (Goodman et al. 2013; Heidug 2013):

- pressure and temperature conditions in the saline formation are adequate to keep the CO_2 liquid or supercritical (usually by setting a vertical upper limit on included storage formations of at least 800 meters [m], and the USGS (2013) set this limit at about 914 m);
- a suitable seal system is present, such as a sufficiently impermeable caprock, to isolate the CO_2 from potable water sources, the surface environment, and the atmosphere; and
- a combination of hydrogeological conditions and trapping mechanisms is present to retain the injected CO_2 within the formation.

All of the estimates of CO_2 storage resources in Table 1 are intended to represent the fraction of the total pore volume in the storage formations that can ultimately be occupied by injected CO_2, no matter how long it takes. So, none of the estimates of storage potential in Table 1 are a function of time-dependent variables. Other than consideration of the EPA's regulations under the Safe Water Drinking Act, economic, legal, and regulatory considerations are not included in the methodologies, and they assume no lack of accessibility (owing to land-management issues or regulatory restrictions) or any limitations due to economic viability (IPCC 2005; Dahowski et al. 2005, 2011; NETL 2008, 2012; Szulczewski et al. 2012; Goodman et al. 2013; USGS 2013).

Potentially Critical Assumptions

Probably the most critical assumption made in most high-level estimates of CO_2 storage capacity is that any unwanted pressure buildup will be managed, including through the production of brines present in the storage formation. Thus, potential complications associated with excessive pressure buildup (including possible risks of leakage or induced seismicity), which could impose significant constraints on the practical availability of geologic storage capacity, were not considered in the studies by Dahowski et al. (2005, 2011), NETL (2008, 2012), or the USGS (2013) in Table 1. In addition, all of the studies included in Table 1 assumed all DSFs to be open, such that CO_2, displaced brines, and other formation fluids could diffuse away from the injection location into other parts of the storage formation or into neighboring formations. If this diffusion occurs rapidly enough, unwanted pressure buildup could be managed passively (and costlessly) to some extent (Heidug 2013).

Szulczewski et al. (2012) assumed that the DSFs they considered were open, which allowed them to analyze expected pressure conditions caused by the injection and migration of CO_2 inside and outside of the storage formation (absent any brine production). Dahowski et al. (2005, 2011) did not assume any extraction of formation fluids, but they did assume that pressure would dissipate because of migration of displaced brines out of the CO_2 storage reservoir. Their assumption was not limited to storage in DSFs, as they also assumed that brines that may have infiltrated DOGs between production of the oil and gas and injection of CO_2 would be expelled upon repressurization with injected CO_2. The authors suggest that these assumptions could be (too) conservative, but make it more likely that use of their methodology will not lead to overestimation of the total volume of pore space that is available for CO_2 storage.

Uncertainty

Pawar et al. (2015) suggest that part of the inherent uncertainty in a geologic carbon sequestration (GCS) project could be aleatoric uncertainty, which may never be completely resolved (even post-closure). The authors describe the lack of knowledge due to a lack of site characterization as mostly epistemic uncertainty, which can be reduced through further site characterization. In addition, Heidug (2013) warns that gathering more data may not necessarily reduce variability in the final CO_2 storage capacity estimates. In Table 1, although the 2008 and 2012 estimates by NETL (2008, 2012) covered roughly the same formations and geographical area, the range of their U.S. CO_2 storage capacity estimates increased significantly between the two assessments. This could have been mostly owing to a change in NETL's methodology for calculating storage efficiency and capacity in DSFs (Goodman et al. 2013). Because geologic uncertainty is inherent in CO_2 storage estimates and data are sparse, Heidug (2013) and others (e.g., USGS 2013; Causebrook 2014) have argued that probabilistic methods are the best approach to consider the limitations and characterize the uncertainty in CO_2 storage resource assessments. In Table 1, only the methodology for the USGS (2013) estimates of volumetric storage capacity is fully probabilistic (Brennan et al. 2010; Blondes et al. 2013; Brennan 2014).

Uncertainty in the estimates of storage efficiency values or analogous measures such as storage coefficients (Gorecki et al. 2009) can be the most important contributor to uncertainty in CO_2 storage resource estimates (Brennan 2014). There is a widespread lack of quality field data to calibrate accurately the geological and physical parameters used in the estimation of storage efficiency values, and gathering enough data to overcome some inherent geological uncertainties may not be feasible (Spencer et al. 2011). There are multitudes of geologic characteristics and engineering factors that can affect estimates of storage efficiency values. Middleton et al. (2012a) suggest that uncertainty in reservoir permeability could be aleatoric, epistemic, or both. Relative permeability is an important determinant of whether the geologic system can be considered more open or closed, and uncertainty in permeability can heavily influence uncertainty in the estimates of CO_2 storage efficiencies and capacities in DSFs (Eccles et al. 2012; Thibeau et al. 2014; Bachu 2015; Gorecki et al. 2015).

Volumetric Storage Efficiency

A common definition in the literature is that storage efficiency is the fraction of the technically accessible pore volume within a geological unit that can ultimately be occupied by CO_2. All else equal and without active pressure management (like extraction of brines), the volumetric storage efficiency will generally be greater in open geologic storage formations than in closed systems, because the natural diffusion of pressure and flow of formation fluids out of the laterally open formation allows CO_2 to occupy a greater percentage of the available pore space in the storage unit. CO_2 injected into a closed system is not able to readily displace the in situ fluids which results in greater pressure buildup than in a similar open formation, and storage efficiency depends more on the compressibility of the in situ fluids and the rock pore space (Thibeau et al. 2014; Bachu 2015; Gorecki et al. 2015). For the numerous CO_2 storage resource assessment methodologies compared during an IEA workshop that resulted in the recent Heidug (2013) report, the participants in that workshop found that the main differences were in the estimation and application of storage efficiency factors. A scarcity of commercial-scale storage project data to better calibrate the geological and physical parameters used in the estimation of CO_2 storage efficiencies has been largely blamed for variability in storage efficiency estimates. The results of lab experiments and expert opinion have been some of the sources used to fill in missing information. In addition, analysts have relied heavily on computer simulations of the injection process and the results of computer modeling efforts to provide the information necessary to better calibrate the storage efficiency parameters (Gorecki et al. 2009; Causebrook 2014; IEAGHG 2014; Birkholzer et al. 2015).

Of the methodologies applied to generate the estimates in Table 1, only that of Szulczewski et al. (2012) considered any engineering issues or time-dependent variables. For their estimates of migration-limited storage capacity in Table 1, however, they evaluated the volume of CO_2 that could be injected up until the plume just reached a boundary of the formation. The estimate of migration-limited storage efficiency by Szulczewski et al. (2012) was not explicitly dependent on time. Szulczewski et al. (2012) calculated the migration-limited storage efficiency using a reservoir model to simulate CO_2 migration through DSFs (as well as solubility and capillary trapping). The methodologies for generating the estimates of Dahowski et al. (2005, 2011) and NETL (2008) in Table 1 used generic storage efficiency factors based on averages from stochastic simulations or gleaned from the literature, respectively. For the estimates of NETL (2012) in Table 1, the authors estimated storage efficiencies utilizing a log-odds method with Monte Carlo sampling based on lithology. For the USGS (2013) CO_2 storage resource estimates shown in Table 1, storage efficiency was estimated using a fully probabilistic methodology with input data from the formation or analog data from a similar basin, and the authors estimated different storage efficiencies for residual trapping with respect to three different permeability classes (Goodman et al. 2013; Heidug 2013).

Dynamic Storage Efficiency

There is also a time dimension to storage efficiency, but dynamic storage efficiencies were not considered for any of the CO_2 storage capacity estimates in Table 1. Compared to estimating static (volumetric) storage efficiency, estimating dynamic storage efficiency requires consideration of additional economic, engineering, and regulatory factors, including the pattern of CO_2 injection wells, rates of injection, timing of injection, and pressure interference between injection locations. Many of these additional variables will vary from one CO_2 storage project (or site) to another, and Bachu (2015) suggests that dynamic storage efficiencies should be used to estimate CO_2 storage capacities at the local level. Based on limited evidence, dynamic CO_2 storage capacity in open DSFs with no brine extraction (for pressure management) could be significantly lower than the static (volumetric) storage capacity, even for short periods of injection (of approximately 50 years) (Gorecki et al. 2009, 2015; IEAGHG 2014; Thibeau et al. 2014).

The International Energy Agency Greenhouse Gas R&D Programme (IEAGHG) used parameters estimated for a representative open DSF in the Powder River Basin of the United States and representative closed DSFs in the Songliao Basin in China to study the possible implications for estimates of dynamic and volumetric storage efficiencies. The results of this study suggest that the dynamic CO_2 storage efficiencies in DSFs could require injection periods of 500 years or greater before approaching the estimated volumetric storage efficiencies in open systems, but just 50 years in closed systems. The authors of the IEAGHG (2014) report suggest that volumetric estimates of storage efficiency could be applied in an open system if the time horizon is long enough to allow full injection of CO_2 into the pore space (as is assumed for all of the CO_2 storage capacity estimates in Table 1). Their results also suggest that volumetric storage efficiencies could be applied from the start of injection to estimate the CO_2 storage capacity in closed systems. For open systems, they found that dynamic CO_2 storage potential could approach the volumetric CO_2 storage resource potential over very long periods of time (on the order of 100s to 1000s of years), but could significantly overestimate the availability of CO_2 storage resources during shorter timeframes. The authors of this study expressed a major concern with volumetric estimates of CO_2 storage capacity and resources in the literature, which is that the sources of these estimates are not making appropriate distinctions or estimating separate storage efficiencies for DSFs in closed versus open systems (IEAGHG 2014; Gorecki et al. 2015).

Need for Saline Water Extraction

Some authors have argued that even high-level CO_2 storage capacity estimates need to include consideration of hydrogeological limits on storage capacities and the potential impacts on CO_2 injection rates owing to pressure buildup (e.g., Szulczewski et al. 2012; Birkholzer et al. 2015). It is possible that active pressure management may not be necessary during the initial stages of injection into open structures with more than enough capacity to accommodate demanded injection rates. However, the degree of openness can be uncertain (for example, if the data necessary to reliably estimate permeability are lacking), and it will likely be necessary sooner or later to actively manage reservoir pressure in order to occupy a greater fraction of the total volumetric storage capacity with CO_2 (Thibeau et al. 2014; Gorecki et al. 2015). When they are present, production of hydrocarbons and the potentially valuable mineral content of formation fluids can help manage pressure while adding value to a CO_2 storage project, but extraction and processing of just brines is generally considered as only adding to the cost of CO_2 storage. Not allowing costly production of brines in order to store more CO_2 (or store it more safely) can be viewed as placing an economic constraint on available CO_2 storage capacity. In general, estimates of CO_2 storage resources either explicitly or implicitly do not consider this potentially important constraint (Heidug 2013).

No extraction of saline water was assumed for the model that generated the baseline results of the IEAGHG (2014) comparisons. In their sensitivity analysis, however, the authors examined the relative impacts of geologic uncertainty, boundary conditions, the number and types of injection wells used, and brine extraction on CO_2 storage efficiency. They found that allowing brine extraction had by far the largest impact on their results, and alone increased their estimates of effective storage efficiency by as much as 475% for their representative DSFs in a closed system and approximately 100% for laterally open DSFs. They found that the other factors, including geological uncertainty, boundary conditions, and the number and types of wells, did not impact their estimates of storage efficiencies in either open or closed systems as much as pressure buildup, which required lower injection rates in the absence of allowing extraction of saline water (Gorecki et al. 2015). Thibeau et al. (2014) found that volumetric estimates of storage capacities under the assumption of a closed system were much better approximations of the CO_2 storage capacities they derived based on their flow model for four major DSFs (including the Mount Simon Sandstone), which were generally assumed to be open in other studies. Thibeau et al. (2014) suggest that volumetric estimates of storage capacity in closed systems consider constraints owing to pressure buildup in a similar way to how they consider pressure constraints to derive capacity estimates using their flow model.

In their model, Szulczewski et al. (2012) considered the limit on the rate of CO_2 injection to be below that which would cause enough pressure buildup in a DSF to compromise reservoir seal integrity (which could result in potential risks of leakage or induced seismicity). The authors calculated pressure-limited storage capacities based on these (risk-adjusted) injection rates for open DSFs, which vary with the duration of injection. As pressure diffuses in the open system, the CO_2 plume flows until its migration is limited by some boundary (like the presence of a fault) or other condition, and this migration-limited capacity (listed in Table 1) is independent of time. Szulczewski et al. (2012) estimated the pressure-limited CO_2 storage capacity of the Mount Simon Sandstone to be about 15 Gt of stored CO_2 after a period of injection of 50 years (a period of injection estimated to be short enough such that the storage capacity would still be dominated by pressure constraints in this DSF), without any extraction of saline waters. Their estimate of pressure-limited capacity is approximately 10% of NETL's (2010) upper bound on their estimate of the volumetric storage capacity, and it is also about 16% of the mean of the USGS (2013) estimate of the TASR for the same formation. Under the conditions that reservoir pressure could not exceed current and expected regulatory limits during 50 years of injection without brine extraction, Birkholzer and Zhou (2009) estimated the storage capacity for the Mount Simon Sandstone to be between 5 Gt and 13 Gt of stored CO_2 after 50 years of injection, which is between about 5 and 14% of the USGS (2013) mean volumetric estimate. Also for 50 years of injection and not allowing production of saline waters, the IEAGHG (2014) estimated that the dynamic storage capacity (limited by pressure constraints) in their representative open DSF would be between 7 and 12% of the total maximum (volumetric) capacity (Bachu 2015; Gorecki et al. 2015).

COST IMPLICATIONS

Although volumetric estimates of CO_2 storage resources commonly assume that pressure buildup will be managed (primarily by production of saline water) to the extent necessary to safely utilize the estimated storage capacity, estimates of the costs of CO_2 storage do not include the costs of active pressure management. For example, Dahowski et al. (2005) assumed water extraction, treatment, and other costs as part of operation and maintenance of a representative CO_2 storage project equal to zero. Active pressure management may turn out to be the most challenging and costly process for commercial-scale CO_2 storage, and brine extraction could be the most important method to increase storage capacity in DSFs, especially in closed systems (Schrag 2009; Gorecki et al. 2015). If extraction of brines without stopping injection of CO_2 is not feasible, this could significantly reduce storage capacities (IEAGHG 2014). On the other hand, such water management could involve very costly extraction, processing, and disposing of formation fluids; costly adjustment of injection rates, the number of injection wells, and their locations; and/or ceasing injection altogether (Birkholzer et al. 2009; Breunig et al. 2013; Bachu 2015). Other costs that are frequently missing from CO_2 storage studies are those for post-closure monitoring, long-term stewardship and liability (for mitigation and remediation of risks), and costs related to increasing public acceptance of CO_2 storage projects (Rubin et al. 2015).

After pressure-management costs, the most important CO_2 storage costs could be for site characterization to obtain better estimates of permeability, storage reservoir depth, thickness, porosity, fracture pressure, and so forth. Given inherent heterogeneity in the properties of potential CO_2 storage reservoirs, it is likely that additional expenditures for geological characterization to obtain better mappings of the spatial distributions of key parameters will be needed (Eccles et al. 2012). McCoy and Rubin (2009) found that site characterization costs could vary widely for DSFs owing to differences in the geology and physical properties of these potential storage formations. With respect to the total costs of CCS, the results of Middleton et al. (2012a) demonstrate how increased geologic uncertainty can have a significant impact on increasing CO_2 transportation costs through making it necessary to build more flexibility into the CO_2 transportation (pipeline) infrastructure. The authors suggest that the combined cost of CO_2 transportation and storage could become increasingly important relative to the costs of carbon capture (which currently dominate the total costs of CCS projects) because of a greater potential for technological advances and cost reduction in carbon capture than for transportation and storage. If so, consideration of the tradeoff between increasing expenditure on geological characterization efforts and increasing expenditure on design, construction, and deployment of transportation and other CCS infrastructure in order to minimize the impact of geologic uncertainty on the total cost of the CCS projects will also become increasingly important (e.g., McCoy and Rubin 2009; Middleton and Bielicki 2009; Gresham et al. 2010; Eccles et al. 2012).

Cost Estimates for Geologic Storage of CO_2

After accounting for uncertainty in reservoir parameters and properties (including permeability, porosity, thickness, salinity of in situ brines, and others) for regions within 15 DSFs in the United States, Eccles et al. (2012) showed that estimated storage costs could range over three orders of magnitude and average greater than \$100/t CO_2 stored (in 2007 US dollars [US\$]), but the authors also found that about 75% of their total estimated CO_2 storage capacity could be supplied for less than

\$2/t CO_2 after they considered storage capacities and costs together in a spatial framework. Based on the results of modeling four different types of potential storage reservoirs (DSFs) and accounting for the variable (capital) costs of site characterization needed to reduce the different levels of geologic uncertainty in each DSF, McCoy and Rubin (2009) estimated the levelized costs of CO_2 storage (in 2004 US\$) to range between \$0.38/t CO_2 for the least costly case studied to \$8.86/t CO_2 for the most costly case. Also accounting for differences in the geologic reservoir properties between 14 potential storage sites in California, Middleton and Bielicki (2009) estimated CO_2 storage costs to range between \$1.50/t CO_2 and \$5.50/t CO_2. Middleton et al. (2012a) found that variation in reservoir permeability could cause a tenfold change in CO_2 storage costs, and that uncertainty in other key reservoir parameters (such as thickness and porosity) could result in similar cost variation.

The heterogeneity in potential CO_2 storage reservoir types and the inherent geologic uncertainty leads to estimates of storage costs appearing as ranges, similar to most estimates of CO_2 storage capacity. In Table 1, most of the methodologies required detailed statistical analyses to estimate CO_2 storage capacities and resources. In Table 2, the estimated costs may not be based on statistical analyses that are as detailed as those behind the storage capacity estimates in Table 1, and the ranges could be more dependent on the judgment of the authors. Rubin et al. (2015) suggest that CO_2 storage in geologically less prospective storage reservoirs could entail storage costs that are well above the upper bounds of the cost ranges of NETL (2014) and IPCC (2005) in Table 2. Owing to a lack of data and/or adequate methodologies to account for inherent reservoir heterogeneity, the storage cost estimates in Table 2 are likely to be based on average values or even single point estimates of the geologic parameters and physical properties for an entire reservoir, or such generic values could even be applied across multiple reservoirs that are assumed to be similar. In particular, this could be an issue with estimating storage costs in extensive reservoirs with significant geological heterogeneity (which describes many DSFs). The underrepresentation of the spatial variability in reservoir properties could mean that the storage cost ranges in Table 2 do not adequately reflect expected variability in CO_2 storage costs (Eccles et al. 2012).

In Table 2, the range of potential CO_2 storage costs estimated by NETL (2014) was based on availability of a percentage of the storage resource that was estimated according to calculation of an average value of the storage coefficient, and using storage capacity data from NETL's National Carbon Sequestration Database and Geographical Information System (NETL 2016). Older versions of this database were also used to estimate the ranges of potential CO_2 storage capacity in the United States for NETL (2008, 2012) in Table 1. Similarly, the other cost estimates in Table 2 are based on availability of volumetric storage capacity in the potential storage formations that were included in these cost studies. Volumetric capacities for these cost studies were estimated based on storage coefficients (e.g., IEAGHG 2009) or efficiencies (e.g., Brennan et al. 2010; Blondes et al. 2013), and were not dynamic or pressure-limited CO_2 storage capacity estimates. Without considering active pressure management (brine extraction) Eccles et al. (2012) demonstrated an inverse relationship between storage capacity and cost. Since the cost estimates in Table 2 are based on the availability of volumetric capacity, volumetric estimates could substantially overestimate the accessibility of storage capacity without water extraction, and the cost estimates in Table 2 do not include any estimated costs for active pressure management that could be necessary to overcome (pressure and similar dynamic) constraints on the availability of volumetric capacity, the cost estimates

Table 2. Some Estimates of Onshore CO_2 Storage Costs

Source of CO_2 Storage Cost Estimate	Low Estimate	High Estimate	Base Year of Prices	Transportation Costs Included
(U.S. dollars per metric ton of CO_2)				
NETL (2014)	\$7	\$13	2013[a]	No
Dahowski et al. (2011)	\$8	\$10	2005	Yes
Dahowski et al. (2005)	\$12	\$15	2005	Yes
IPCC (2005)	\$1	\$12	2013[a]	No

[a] The ranges of potential CO_2 storage costs in NETL (2014) and IPCC (2005) were converted by Rubin et al. (2015) to a common basis (2013 US\$ per metric ton of CO_2) from estimated costs for base years of 2011 and 2002, respectively

could be too low owing to either exclusion of the costs of active pressure management or a lack of accounting for potentially higher costs of CO_2 storage in reservoirs with far less capacity than assumed to be available.

Other than for the cost estimates by Dahowski et al. (2005, 2011), CO_2 transportation costs are not included in Table 2. However, Rubin et al. (2015) found that many studies of the total costs of CCS have assumed a combined cost for CO_2 transportation and storage. In a comparison of levelized costs of electricity (LCOE) with and without CCS for different power-generating technologies, the authors of Working Group III (WGIII) of the IPCC's contribution on mitigation in the IPCC (2014) report on climate change assumed the combined costs of transportation and storage of CO_2 to be about \$10 per metric ton (\$10/t) CO_2 (at 2010 prices) (IPCC 2014). Rubin et al. (2013) have pointed out that LCOE can be useful for comparing the costs of implementing different (emissions mitigation) technologies in the power sector, but may not accurately account for specific CCS project costs, including costs of transportation and storage of the captured CO_2. Heddle et al. (2003) estimated costs for transportation and injection between \$3 and \$5.50 per metric ton of CO_2 emissions avoided, and they estimated the total cost range as possibly between \$2 and \$15 per metric ton of CO_2 emissions avoided. In order to net out transportation costs, these authors estimated that the annual costs of CO_2 transport for each 100 km of pipeline as a function of the CO_2 mass flow rate from a representative IGCC plant could be between \$1.50/t CO_2 and \$2/t CO_2 after economies of scale have been reached.

Dahowski et al. (2005)'s estimates of CO_2 transportation and storage costs for DSFs (without any offsetting revenues) in North America could average about \$12.50/t CO_2 (with a range of \$12/t CO_2 to \$15/t CO_2 at 2005 prices); that for depleted gas fields (also without any offsetting revenues) could average about \$12.50/t CO_2 (but within a tighter range of \$11/t CO_2 to \$13/t CO_2); that for depleted oil fields (including estimated offsetting revenues from sales of any oil recovered from an EOR process), about \$16.60/t CO_2 (–\$13/t CO_2 to \$37/t CO_2); and that for coal seams (including estimated offsetting revenues from sales of any enhanced coalbed methane recovery), about \$9.50/t CO_2 (–\$7/t CO_2 to \$30/t CO_2). Their cost estimates also include costs of \$0.03/t CO_2 for seismic monitoring and verification of the CO_2 plume during a 30-year period of injection (Myer et al. 2003). Compared with their earlier cost study (Dahowski et al. 2005), Dahowski et al. (2011) estimated lower costs (at constant 2005 prices) mostly owing to improvements in their methodology, and owing to a greater availability of geologic data (Table 2). In addition to the storage cost estimates in Table 2, the IPCC (2005) special report on CCS suggested that estimates of monitoring costs could range between \$0.1/t CO_2 to \$0.3/t CO_2. These monitoring costs are substantially higher than that used by Dahowski et al. (2005), and this could reflect the IPCC special report including costs for additional post-closure monitoring (IPCC 2005). Interestingly, the NETL (2014) estimates of storage costs include costs for the storage operator to assume some financial responsibility for risk by paying into a long-term liability fund, but this is the only known example of accounting for the possible costs of long-term stewardship and liability in CO_2 storage cost models.

Cost of Saline Water Production

Harto and Veil (2011) note that the costs of managing the incremental production of water at new CO_2 storage operations will vary significantly between locations in the United States where there are suitable geologic formations to inject the saline water, and those where there are not. Absent commercial uses for extracted brines and using current prices between 1992 and 2006, the authors estimated the average cost just for simple discharge at about \$0.10/bbl produced brines, and even these extremely low simple discharge costs correlate to an estimated cost range from \$0.80 to \$0.95/t of CO_2 stored. It is more likely that the brines will have to be transported before injection, processed through evaporation, treated for recycling, or otherwise processed before disposal. Then, the average costs could be about \$1.50/bbl of produced waters, and this would correlate to an increase in the cost of carbon storage by between \$12/t and \$14/t of stored CO_2. If more advanced thermal treatment or long-distance trucking for the disposal of produced waters with high content of total dissolved solids is required, then the average costs could be about \$7/bbl of produced waters, and the authors estimated that this could increase the costs of CO_2 storage by between \$57/t and \$67/t of CO_2 stored.

The cost estimates of Harto and Veil (2011) are somewhat dated, and not corrected for inflation.

They may also not include formation fluid lifting costs and some other potential costs of water management. If converted to costs at current prices, these rough estimates of the potential costs of active pressure management for CO_2 storage could be even higher. Taken at face value, addition of the most likely costs of (saline) water management ($12/t and $14/t of stored CO_2) would at least double most of the CO_2 storage cost estimates in Table 2, and they would have an even greater impact on most of the other costs estimates mentioned in this review. These costs for management of saline waters were based on analogs for producing waters associated with oil and gas production, and they may need to be better estimated in order to quantify the costs of producing brines from DSFs targeted for CO_2 storage. Still, they provide at least a rough quantification of probably the most important costs that will be necessary to utilize more than just the pressure-limited fraction of the volumetric CO_2 storage capacity.

Harto and Veil (2011) suggest that a possible revenue stream could be obtained from extracting valuable minerals (such as lithium and potash) from the produced saline waters, which could help offset the cost of active pressure management for CO_2 storage in DSFs. Also, the U.S. Department of Energy recently selected two projects to test emerging enhanced water recovery (EWR) technologies for their potential to produce useable water from CO_2 storage sites (EIN Presswire 2016). The technologies for value-added CO_2 storage via EOR projects are already well established, and the extraction of hydrocarbons during these projects naturally mitigates pressure buildup. Two assumptions that are common for estimating the CO_2 storage capacity in DOGs are that the entire volume previously occupied by hydrocarbons will be available for CO_2 storage, and that the seals of the hydrocarbon reservoir will safely contain the volume of injected CO_2 as long as the storage operator does not allow the pressure to exceed the fracture pressure of the reservoir (Bachu et al. 2013). It is unlikely that these same types of assumptions can be made with respect to containment of the (non-buoyant) brines in DSFs without costly production of brines (Birkholzer et al. 2009; Heath et al. 2014).

CO_2 Storage Cost-supply Curves

Dahowski et al. (2005, 2011), Middleton and Bielicki (2009), Eccles et al. (2012), and NETL (2014) have derived and analyzed CO_2 storage cost-supply curves at national, regional and smaller scales. The successive points on these curves typically correspond to estimated net costs for each additional metric ton of CO_2 transported from an anthropogenic source (generally a power plant or other industrial plant), injected, and permanently stored in the storage reservoir. The points on such cost-supply curves are ordered from bottom to top (and left to right) from the least costly to the most costly potential source-sink pairing for CCS, where each of the potential CO_2 sinks is matched with one or more sources of captured CO_2 for which it is the lowest-cost storage option.

In Figure 2, the horizontal axis tracks how much cumulative CO_2 (in Mt/year of CO_2) can be stored annually in all technically accessible storage reservoirs. This is based on volumetric estimates of storage capacity in each reservoir, and (hence) is independent of time. Dahowski et al. (2005) suggest that this cost curve could provide a possible pattern of use of CO_2 storage resources. It is meant to represent a situation where all major emitters of CO_2 in the region capture all of their current CO_2 emissions and simultaneously seek to store all of the captured CO_2 in the lowest-cost geologic storage locations for each, which in many cases were found to be directly underneath them (Dahowski et al. 2005).

The cost curve (Fig. 2) is generally upward sloping, but is dominated by an essentially flat section in the middle that indicates a very tight cost range for using a vast majority of the estimated potential storage capacity in North America. The flat area of this curve is mostly composed of pairwise points for sources storing captured CO_2 in nearby DSFs (and in some DOGs where there is zero expected enhanced recovery of hydrocarbons). In turn, the expected costs of transportation and storage of CO_2 in DSFs dominate the total storage costs for the entire region. After aggregating these storage cost curves of North America over the expected lifetime of all the potential storage reservoirs (until they are expected to be filled with CO_2), the authors estimated that storage in DSFs could account for 3,700 Gt CO_2 out of about 3800 Gt (about 97%) of their total estimated CO_2 storage capacity in North America [which is comparable with volumetric estimates of storage capacity in the region (e.g., NETL 2012)], at an average cost of $12.50 per metric ton of CO_2 transported to and stored in DSFs (Dahowski et al. 2005; Dooley et al. 2008).

Despite storage in DSFs dominating the regional capacity and cost estimates represented in

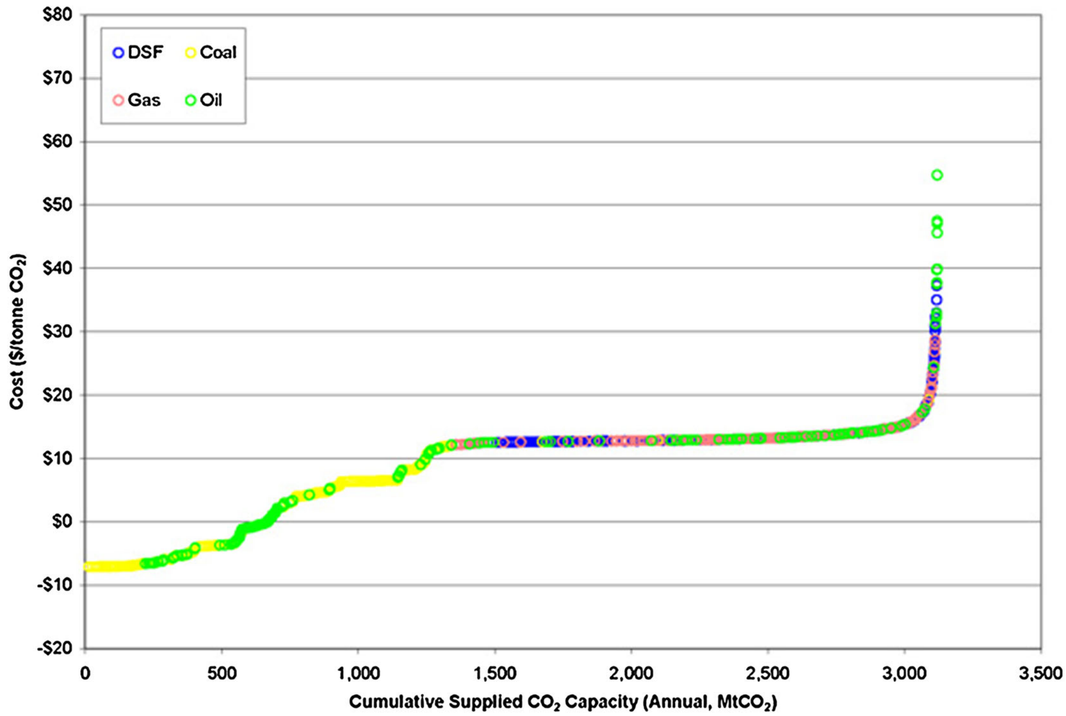

Figure 2. CO_2 storage cost curve for North America (reference case from Dahowski et al. 2005, p. 80, and courtesy of Battelle Memorial Institute).

Fig. 2 and in similar storage cost-supply curves (e.g., Dahowski et al. 2009, 2011), the inherent geological heterogeneity and spatial variability in the physical properties within (or even across all of) these important storage reservoirs are generally not considered. Thus, the differences in combined transport-storage costs (which are slight) for most of the curve in Figure 2 are primarily owing to differences in transportation costs that correspond to increasing distances between minimum-cost source-sink pairings. They do not accurately reflect the differences in the quality of the storage reservoirs. Integrated transportation-storage cost models (e.g., Middleton and Bielicki 2009) could be better at accounting for the effect of geologic uncertainty and economic differences between storage sites on transportation and storage costs, but may still report cost estimates as averages that do not adequately reflect the degree of variation in storage costs (Eccles et al. 2012).

In addition, Dahowski et al. (2005) warn that their pairwise minimum-cost curves should not be interpreted to imply some strict chronological progression of CO_2 storage from left to right, where the minimum-cost source-sink pairings in a region would necessarily begin CCS operations earlier than higher-cost pairings. The actual progression of CO_2 storage over time may not follow such a static snapshot over such a large region as North America. There is likely to be variability in the timing and requirements of applicable regulations, in the costs of capture and processing at the point source (which could dominate the total costs of a CCS project), in the magnitude of necessary up-front investment and financing, and other factors that could affect the eventual timing of CCS development at the local level (Eide et al. 2014).

Dynamic Costs of CO_2 Storage

Dahowski et al. (2005) suggest that more robust modeling of the depletable nature of the CO_2-storage resource over time could provide very different results concerning the pattern of CCS deployment, and that it is difficult to reconcile the results of such a static model of CO_2 storage cost and supply as theirs with that of dynamic economic models of depletable resources. However, recent estimates of dynamic CO_2 storage capacity (e.g., IEAGHG 2014) have not explicitly estimated dynamic storage costs.

Using an integrated assessment modeling (IAM) approach to do a preliminary analysis of global potential for CCS over time, Dooley et al. (2005b) assumed that the costs of CO_2 storage depend on the number of reservoirs available in the region, the amount of the reservoirs' capacity previously filled, and the grade (measured according to estimated injectivity, distance from the CO_2 source, and other reservoir properties) of the storage reservoirs being filled at the current time. The authors also assumed that the lowest net-cost storage reservoirs would be filled first, and the more costly (such as reservoirs with lower injectivities) would be utilized as the lower-cost (including value-added) storage options are filled. In their model, the marginal costs of storage are increasing over time, and their results are consistent with viewing the geologic CO_2 storage resource as a depletable natural resource. Based on a very similar model, Edmonds et al. (2007) suggest that the result of monotonically increasing costs of storage reflects the assumption that lower-cost storage reservoirs will be filled before higher-cost reservoirs. They estimate a global average lowest cost for onshore storage in DSFs to be about \$18/t of carbon (C) and the highest cost of onshore storage in DSFs to be about \$367/t C, which would convert to about \$5/t of CO_2 and \$100/t of CO_2, respectively.

Dooley et al. (2005b) and Edmonds et al. (2007) perform sensitivity analyses to account for uncertainty by considering that all of the volumetric storage capacity will be available with certainty, and then arbitrarily limit the practically available storage capacity to 50 or 10% in order to see what effects that would have on their results. The authors suggest that these limits on the practically available capacity could reflect geologic (data) uncertainty, as well as account for possible uncertainties regarding potential economic, political, and technological constraints on available CO_2 storage capacities. In the United States, Edmonds et al. (2007) estimated that the storage capacity was sufficient to ensure that the costs of storage would remain below \$100/t C (about \$27/t of stored CO_2), even after a century of continuous injection, under the most extreme case of only 10% of total storage capacity being available, and assuming that policy would require a drastic reduction in CO_2 emissions to achieve the lowest considered stabilization of CO_2 concentration (450 parts per million CO_2) in the atmosphere. In the other cases of only 10% of the storage resource being available, U.S. storage costs were never projected to exceed \$50/t C (about \$14/t of stored CO_2) after 100 years of injection.

Dooley et al. (2005b) projected that the rate of CO_2 storage over time in the United States could be non-decreasing, even with only 10% of technically accessible storage resource available. Thus, the depletable nature of the CO_2 storage resource was not evident for the United States during the first 100 years of injection in their model. However, the rate of CO_2 storage did decrease in most of the other countries and regions included in their study, which the authors claim demonstrates the depletable nature of the resource. Their results suggest that if only a fraction of volumetric storage capacity is available for CO_2 storage, possibly owing to geologic uncertainty, or uncertainty about additional economic, political, legal, or other constraints (including limitations imposed by excessive pressure buildup, an inability to produce and dispose of formation fluids at low cost, or potential risks of CO_2 storage), then the costs of CO_2 storage could escalate quite rapidly (on the order of decades) if demand for CO_2 storage remains consistent with the capture of (and need to dispose of) most of the current flow of CO_2 emissions from existing stationary sources.

DISCUSSION

Even if just considering the most recent lower-bound estimates of U.S. storage capacity in Table 1, it would appear as if U.S. storage capacity is sufficient to store 1800–2000 Gt of CO_2. If this storage capacity is not just theoretical but will be practically available and economically feasible, then it would far exceed most projections of U.S. demand for geologic storage capacity over the next 100 years, which are on the order of 10 s of Gt and far less than even 100 Gt of CO_2 storage capacity (Edmonds et al. 2007; Koelbl et al. 2014a, b). That is, it could be enough storage capacity for fossil fuel use for power generation (with CCS) to conceivably continue in the country for far longer than 100 years (without the power sector emitting any more CO_2 to the atmosphere). In addition, the results of Dahowski et al. (2011) suggest that a vast majority of this huge volume of potential CO_2 storage capacity could be supplied for just \$8–\$10 per metric ton of stored CO_2, and other recent storage cost estimates are compatible with theirs (Table 2). However, if only 5–15% of the volumetric storage capacity is practically available (owing to pressure buildup), the availability of storage capacity is constrained even beyond that (after consideration of land-management or regulatory restrictions, pore-space rights, risk and liability, and other issues), and some important costs that are missing from current storage cost estimates are included, then a policy of maintaining current levels of fossil-fuel use in power generation (with CCS) as long as fossil fuels are economically available may be far more costly than under the assumption of unconstrained availability of the TASR.

Estimates of CO_2 storage capacity and costs that consider the inherent geologic uncertainty, spatial distribution of reservoir properties, pressure buildup, feasibility of injection rates, and economic issues would be more helpful to policy makers trying to determine the realistic potential, likely costs, and probable pattern of deployment for CCS as an option to mitigate emissions (Eccles et al. 2012; Heidug 2013). Nationwide deployment of commercial-scale CCS projects could be essential to achieve climate goals. Given the potential limitations on CO_2 storage capacity outlined in this review, however, deployment of CCS will probably be at costs that are significantly higher than current estimates, and the length of time CO_2 can be injected for storage (at low enough cost) could be much shorter than current projections. More estimates of CCS costs are needed that better account for the impacts of geologic uncertainty on costs, such as the potential effects of geologic uncertainty on CO_2 transportation costs and other components of the CCS system (Eccles et al. 2012; Middleton et al. 2012a).

The participants in the IEA workshop to determine best methods for assessing CO_2 storage reserves suggested that more and better contingent capacity estimates should be made available that consider constraints such as pressure buildup (Heidug, 2013). What are still needed are more and better estimates of contingent CO_2 storage capacities (at many scales), the spatial distribution of that constrained capacity, and how much it is expected to cost to access it (including possibly higher costs for a more extensive and flexible CO_2 transportation infrastructure network). There are some models in the literature that estimate pressure-limited and migration-limited capacities (e.g., Birkholzer and Zhou 2009; Person et al. 2010; Szulczewski et al. 2012, 2014), but still missing are estimates of the expected costs of CO_2 transportation and storage when only such subsets of total volumetric capacity are available. Since pressure limitations are probably the constraint on storage capacity that will be of greatest concern (with respect to the consideration of potential risks and other issues), pressure-limited capacity could be the most important contingent capacity to evaluate. After there are widespread estimates of pressure-limited capacity, then it will be possible to study the spatial distribution of that contingent capacity relative to the locations of major sources of CO_2, and evaluate the need for and the costs of expanding that capacity (through extraction of formation fluids) as projected to be necessary to accommodate demand. This information could be useful to policy makers, even if the future amount of CO_2 that will be produced, the policies and incentives with regard to limiting those CO_2 emissions, and the demand for geologic storage capacity are highly uncertain (Middleton et al. 2012b; IPCC 2014).

Estimates of contingent CO_2 storage capacities and costs will probably not be available soon enough to allow optimal deployment of CCS in time to meet some emissions targets (Sanderson et al. 2016). Still, it may be possible to determine the percentages of the storage resource that can be classified as open, closed, or semi-closed, in order to create economic classes or subsets of the potential storage resource within a useful timeframe. Injectivity might also be a parameter that could be considered as part of the development of an economic ranking of potential CO_2 storage reservoirs. The USGS (2013) assessment includes injectivity classes for potential storage reservoirs. Lower injectivity could imply higher storage costs per volume of CO_2 owing to the need for a greater number of injector wells and other expenditures to increase the injectivity to a point that these reservoirs can accommodate the flow of captured CO_2 from the nearest sources (Dooley et al. 2005b). The data behind the other high-level CO_2 storage capacity estimates in Table 1 likely include similar indicators of which potential storage reservoirs could be more costly to develop and operate. In addition, there is still a need for studies to develop further estimates of CO_2 storage capacities, demand, and costs over time. More estimates of dynamic storage efficiency and capacity than just for limited case studies (e.g., Jin et al. 2012; IEAGHG 2014) are needed, and it would be helpful if modeling of the evolution of storage costs over time could be included as a part of this effort.

In the absence of these suggested analyses, there are interesting scenarios that can be (or have been) discussed based on the available data and information presented in this review. The volume of formation fluids that would have to be produced to mitigate risks or increase the practically available CO_2 storage capacity in the storage reservoir will vary based on the openness of the geologic system (Zhou et al. 2008; IEAGHG 2014). Harto and Veil (2011) assumed a 1:1 ratio of extracted brines to the volume of CO_2 injected, but there are currently injections of CO_2 in open formations that do not require any extraction of brines or other formation fluids. The volumes of CO_2 currently being injected are far less than that expected to be necessary to affect CO_2 concentrations in the atmosphere, but the costs (thus far) could fall within the ranges of the costs estimates in Table 2. It could be well into the period of injection before storage operators could have to start extracting formation fluids. Even then, they would probably not have to bear the full costs of pressure management suggested by the study of Harto and Veil (2011) until after ramping up to extract formation fluids at a ratio of 1:1 to the volume of CO_2 injected. The length of time the storage operator can safely delay bearing the full costs of CO_2 storage (including the costs of 1:1 extraction of formation fluids per volume of injected CO_2) could be longer the more open the geologic storage formation.

Other possible scenarios not considered in Dooley et al. (2005b) or Edmonds et al. (2007), are that it could be economical for a country like the United States that has relatively abundant storage capacity to import and store CO_2 from countries that do not, or that there have been recent expressions of a need for ''negative emissions'' of CO_2 that could lead innovators to develop more efficient technologies to recover CO_2 from the atmosphere for storage underground (IPCC 2014). If demand for CO_2 storage capacity continues to increase, the costs of CO_2 storage could increase rapidly (Koelbl et al. 2014a), especially once the pressure-limited capacity is filled and storage operators have to start significant pressure management. Even with inclusion of pressure-management costs, however, CO_2 storage costs could still be far less than the costs of CO_2 capture in projecting the future costs of commercial-scale CCS (Koelbl et al. 2014b; Rubin et al. 2015).

CONCLUSIONS

To summarize the main finding of this paper, only a fraction of the theoretical CO_2 storage capacity estimated in high-level assessments could be available without paying the significant (possibly prohibitive) costs of active pressure management. Most high-level assessments of the TASR have recognized this and either explicitly or implicitly assume that any pressure management needed to control pressure buildup and utilize the entire volumetric storage capacity in the storage reservoir will happen (Heidug 2013). However, estimates of the potential costs of CO_2 storage that rely on unconstrained availability of the volumetric storage capacity do not include costs for the pressure management that will likely be necessary to provide access to a vast majority of that potentially huge storage resource.

Other findings include that pressure management occurs naturally with the extraction of hydrocarbons in CO_2-EOR projects, and the revenue from selling this production can add value to (offset the costs of) a CO_2 storage project. The downside is that depleted oil and gas reservoirs and other buoyant traps have been estimated to only account for about 2% of the TASR in the United States, and they could be filled with CO_2 very soon after full deployment of CCS in the country. Almost all of the remainder of the nation's CO_2 storage capacity is estimated to lie inside DSFs, for which the costs of pressure management (to extract the saline water, process it, and safely dispose of it) could easily more than double current estimates of the costs of CO_2 storage in these extensive formations. Some static analyses in the literature suggest that the annual cost of CO_2 transport and storage could be fairly constant and quite low for at least a century of commercial-scale injection of CO_2 in the United States (e.g., Dahowski et al. 2005, 2011), although other more dynamic models of the potential evolution of CO_2 storage suggest that the marginal cost of CO_2 storage could be increasing over time (e.g., Dooley et al. 2005b; Edmonds et al. 2007; Szulczewski et al. 2012; IEAGHG 2014). Uncertainty in the availability of CO_2 storage capacity and in the storage costs could significantly contribute to uncertainty in what the full costs of commercial-scale deployment of CCS will be (Dooley et al. 2005a).

In countries and regions that have been estimated to have sufficiently abundant CO_2 storage resources (including the United States), it could be that the depletable nature of geologic CO_2 storage resources will not affect storage costs as much (even after 100 years or more of commercial storage), especially if the estimated storage capacity in DSFs can be utilized with little or no active pressure management. However, investors could be hesitant to sink the necessary capital into capturing CO_2 if they have reason to expect that only 10% or less of estimated volumetric capacity will be practically available (e.g., Dooley et al. 2005b; Edmonds et al. 2007; Dahowski et al. 2009), or that pressure buildup will significantly constrain storage capacity in the potential storage reservoir (e.g., Birkholzer and Zhou 2009; Szulczewski et al. 2012). This could overlap with or be in addition to the effects on investment timing of uncertainty in the possible leakage risk and/or risk of induced seismicity (Zoback and Gorelick 2012), questions concerning long-term liabilities, and other issues which are assumed away in most estimates of CO_2 storage capacity and storage costs (Eide et al. 2014).

Implementation of CCS could be a necessary part of a least-cost strategy to achieve climate-change goals (IPCC 2014). Consideration of cost and capacity uncertainty could be critical for optimal deployment of CCS on a commercial scale. However, policy makers may have to make crucial decisions concerning how best to deal with CO_2 emissions before any of the desirable information described in the discussion section of this review is available. Given the current state of available information and the scarcity of (data from) long-term commercial-scale CO_2 storage projects, decision makers may experience considerable difficulty in ascertaining the realistic potential, the likely costs, and the most beneficial pattern of deployment of CCS as an option to reduce CO_2 concentrations in the atmosphere.

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