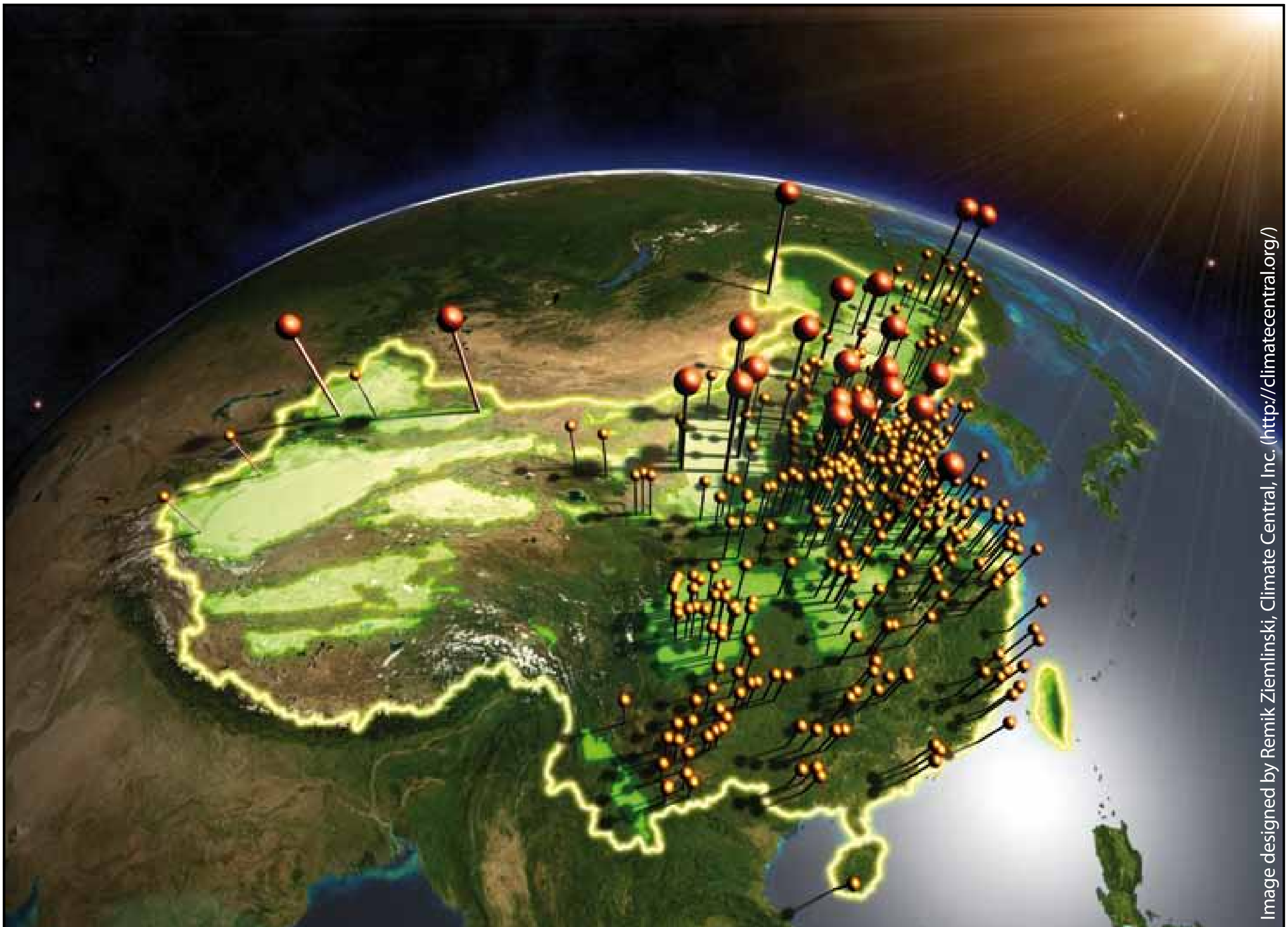

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Title: Near-Term Mega-Scale CO_2 Capture and Storage Demonstration Opportunities in China

CO_2 source-sink matching identifies low-cost opportunities for large-scale CO_2 capture and storage demonstration projects. The pins mark concentrated CO_2 emission sources. The larger pins mark sources greater than 1 million tonnes/yr in close proximity to deep saline aquifers (green) that may be suitable for CO_2 storage..

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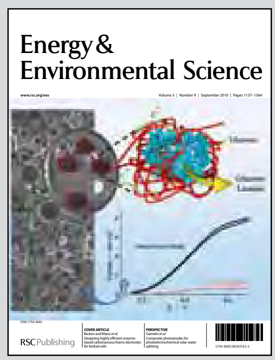

See Z. Zheng, E. D. Larson, Z. Li, G. Liu and R. H. Williams, *Energy Environ. Sci.*, **3**, 1153

Near-term mega-scale CO_2 capture and storage demonstration opportunities in China

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China is unique in the large number (nearly 400) of existing and planned projects for making ammonia, methanol, and other fuels and chemicals from coal. A natural by-product of these processes is a nearly pure CO_2 stream. Collectively, these facilities will emit (once all are operating) some 270 million tonnes of CO_2 per year. Taking advantage of the relatively low cost of capturing these CO_2 streams (as compared with capturing CO_2 from power plant flue gases), some of the 20 large-scale CO_2 capture and storage (CCS) demonstration projects called for by the leaders from the G8 to be deployed during the next decade might be expeditiously located in China. Our analysis identifies 18 coal-chemicals/fuels facilities, each emitting one million tonnes/year or more of CO_2, that are within 10 km of prospective deep saline aquifer CO_2 storage sites and an additional 8 facilities within 100 km. The potential CO_2 storage basins are identified based on work by others. We adapted two published cost models for CO_2 compression and transport to develop preliminary estimates of prospective costs for potential CCS projects in China. Our "N^{th} plant" cost estimates for the 18 projects where the CO_2 source is within 10 km of a sink, are between \$9 and \$13/tonne of CO_2. (The highest cost estimate among all evaluated projects was less than \$21/tonne of CO_2.) The 10-year net-present value cost for projects ranged from \$89 million to \$1.15 billion, with more than 75% of the projects having net present value costs of \$200 million or less. These relatively modest CCS costs suggest that there would be mutual value in international cooperation to support CCS demonstrations in China.

1. Introduction

Scientists of the Intergovernmental Panel on Climate Change (IPCC) have reached favorable judgments about the prospects for CO_2 capture and storage (CCS) as a major carbon mitigation option (Box 1). It is now widely recognized that the most significant obstacle to the routine pursuit of CCS is successful demonstration of CO_2 storage at the 'mega-scale' in geological formations—with emphasis on deep saline formations, which account for most of the geological storage opportunities. (To characterize the size of needed demonstrations, the term "mega-scale" is often used—a word that refers to the geological storage of at least one million tonnes of CO_2 per year per project.) Such projects are needed not only to address scientific questions that can only be answered in projects that inject and store CO_2 at rates comparable to those for commercial projects but also to demonstrate to the satisfaction of a wide range of stakeholder groups that CCS is a viable major option to be included in the portfolio of carbon mitigation options. Such projects are also needed to provide the experience base needed for formulating practicable regulations governing CO_2 storage.

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Broader context

Although theoretical studies and pilot projects have shown the promise of CO_2 capture and storage (CCS), commercial-scale demonstration projects are needed to address technical issues of scale and to provide an empirical basis for judgments on CCS viability as a major carbon mitigation option. G8 leaders have called for 20 large-scale CCS demonstrations during this decade. We analyze opportunities for near-term projects that would exploit a unique demonstration opportunity in China: hundreds of existing or planned facilities that make chemicals or fuels from coal, each naturally producing a nearly pure CO_2 stream. We identify 18 facilities, each emitting at least one million tonnes/yr of CO_2, that are within 10 km of prospective deep saline aquifer CO_2 storage sites and an additional 8 facilities within 100 km—although local geological investigations are needed to ascertain the suitability of these prospective sites for secure storage. For these CO_2 source–sink pairs, we estimate that the costs to capture and store the CO_2 would be far less than costs for CO_2 captured from power-plant flue gases. With such low costs, several large-scale demonstration projects might be expeditiously located in China, and there would be mutual value in international cooperation to support these projects.

Box 1: the IPCC and carbon dioxide storage

The IPCC Special Report on Carbon Capture and Storage[1] includes a detailed review of the state of scientific understanding (as of the first half of this decade) relating to the prospects for carbon dioxide capture and storage. Some of the key statements in the report include:

…Models…indicate that CCS systems will be competitive with other large-scale mitigation options such as nuclear power and renewable energy technologies…

…Available evidence suggests that, worldwide, it is likely that there is a technical potential of at least about 2000 Gt CO_2 storage capacity in geological formations… (For perspective, global CO_2 emissions in 2005 from fossil fuel burning were 27 Gt CO_2).

…With appropriate site selection informed by available subsurface information, a monitoring program to detect problems, a regulatory system, and the appropriate use of remediation methods to stop or control CO_2 releases if they arise, the local health, safety and environment risks of geological storage would be comparable to risks of current activities such as natural gas storage, enhanced oil recovery, and deep underground disposal of acid gas…

…Based on observations and analysis of current CO_2 storage sites, natural systems, engineering systems, and models, the fraction [of injected CO_2] retained in appropriately selected and managed reservoirs is very likely to exceed 99% over 100 years and is likely to exceed 99% over 1000 years…

…The inclusion of CCS in a mitigation portfolio is found to reduce the costs of stabilizing CO_2 concentrations by 30% or more…

…Based on the TAR (the Third Assessment Report of the IPCC) *mitigation scenarios, the average share of CCS in total emissions reduction may range from 15% for scenarios aiming at stabilization of CO_2 concentrations at 750 ppmv to 54% for 450 ppmv scenarios…*

Having CCS as a major carbon mitigation option is especially important to coal-intensive energy economies such as those of China and the United States.

An international political framework for early CCS action has already been established. At the July 2008 G8 Summit in Japan an agreement was reached by the G8 countries that twenty large-scale fully integrated CCS demonstration projects worldwide would be committed by 2010 and deployed by the middle of the next decade, with the aim of establishing the basis for broad commercial deployment of CCS technologies after 2020. The US agreed to host at least 10 of these projects. In July 2009, the leaders of the G8 countries re-iterated their July 2008 call.[2]

Much if not all of the incremental cost of CCS for the 20 projects called for by the G8 will probably have to be paid for by governments (individually or collectively) because of the likelihood that in many if not most parts of the world carbon prices will be lower initially than what will be needed to make pursuit of CCS a profitable activity for private companies.

If governments will have to pay for the incremental CCS cost they will want to pursue projects in which they can maximize the learning about the giga-scale prospects of CCS per dollar (or per Yuan) spent. An important consideration is that systems making chemicals or synfuels from coal, generate, as a natural part of the process of their manufacture, relatively pure streams of CO_2† for which the incremental cost of CO_2 capture is very low—a fact that can be exploited to facilitate lower-cost early CCS action, as discussed below.

China is unique in the large number of existing and planned projects for making NH_3 and other chemicals from coal. This uniqueness stems from the fact that China has limited domestic oil and natural gas resources and so has evolved a chemical industry that is based mainly on coal as a feedstock. Taking advantage of CO_2 streams generated in this industry, some of the 20 integrated CCS projects called for by the G8 to be deployed during the next decade might be expeditiously located in China.

Meng, *et al.*[3] conducted an early evaluation of the possibility of utilizing CO_2 streams from NH_3 plants in China for CO_2 storage demonstration projects. They identified nine specific plants located within 150 km of potential CO_2 storage sites (deep saline aquifers, operating oil fields for enhanced oil recovery, and unmineable coal seams). Here we build on the work of Meng *et al.* by identifying a considerably larger number of existing and planned facilities that vent pure CO_2 streams in the process of making ammonia, methanol, or synfuels *via* both direct and indirect liquefaction [Fischer–Tropsch liquids (FTL)] processes. Existing facilities offer the potential for near-term capture projects, while facilities still in the planning stages offer opportunities for more-optimized capture/storage projects. Our analysis also reviews research on prospective CO_2 storage opportunities carried out since the Meng *et al.* paper was published. The larger number of CO_2 sources, together with the newer research on potential CO_2 storage sites enables us to put forth a more comprehensive analysis of the possibilities for matching CO_2 sources and sinks that might provide the basis for mega-scale demonstration projects in China. We additionally provide preliminary estimates of prospective costs for such projects.

† To illustrate, a byproduct of the production of about 140 000 barrels per day of synthetic liquids (*3/4 fuels,1/4 chemicals*) from coal by Sasol at its two Secunda plants in South Africa is the production of streams of pure CO_2 that are vented at a rate of 20 million tonnes per year[1]—making this the largest point source of pure CO_2 emissions on the planet.

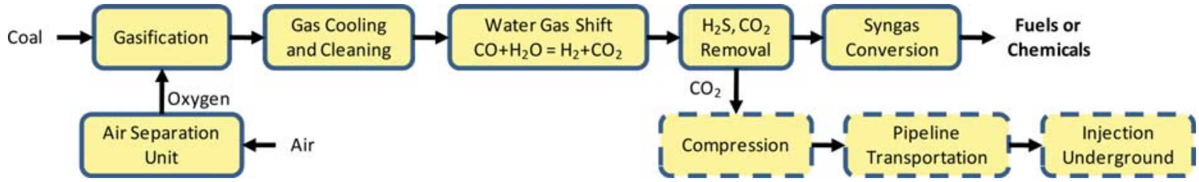

Fig. 1 Schematic of coal to chemicals or synfuels plants.

2. Low-cost CO_2 sources in China

When CO_2 is captured post fossil fuel combustion from flue gases (in which its concentration is 3–15%[1]), the capture cost is made up of costs for: (*i*) extraction of CO_2 from the flue gases using an appropriate chemical solvent, (*ii*) the recovery of the CO_2 as a pure stream from the solvent and regeneration of the solvent for reuse, and (*iii*) compression of the CO_2 to the pressure needed for transport by pipeline to the CO_2 storage site. Of these CO_2 capture cost elements, the only one required for capture at coal-to-chemicals or coal-to-synfuels plants is the relatively modest cost of CO_2 compression, because removing CO_2 as a nearly pure stream is part of the coal-to-chemicals or synfuels production process and is thus paid for as an inherent part of that process.[4]

Fig. 1 is a generic representation of a coal-to-chemicals or synfuels process. Gasification of coal using oxygen from an air separation unit (ASU) produces a synthesis gas consisting primarily of CO and H_2. After cooling and cleaning, the gas composition is adjusted in a water gas shift reactor to achieve the desired CO-to-H_2 ratio for efficient further processing. Consider an ammonia plant.‡ In this case the shift reaction proceeds to the extent of producing essentially only H_2 and CO_2. The CO_2 would be separated from the H_2 using one of several available commercial acid gas removal technologies. The H_2 would then be combined with nitrogen also derived from air *via* the ASU to make ammonia. At a typical fertilizer factory, about 40% of the CO_2 would be reacted with the ammonia to make urea. The remaining CO_2 is vented to the atmosphere. Alternatively, the CO_2 now vented could be compressed for pipeline transport and underground injection, as depicted in Fig. 1. The pressure at which the CO_2 is available to a compressor varies depending on the acid gas removal technology adopted.§ Compression costs are lower at higher recovery pressures.

To estimate the emissions of pure streams of CO_2 from selected coal conversion facilities in China, we apply emission factors (EFs) drawn from various sources. For coal-to-ammonia plants we assume an EF of 3.27 tonnes CO_2/tonne NH_3.¶ For coal-to-methanol plants, we assume 1.55 tonnes CO_2/tonne MeOH.[9] For coal-to-synfuels, we assume for Fischer–Tropsch liquids 4.74 tonnes CO_2/tonne FTL[4] and for direct coal liquefaction 2.88 tonnes CO_2/tonne liquids produced.‖

These emission factors were applied to the estimated production levels of almost 400 facilities that we identified from literature sources,[5,7,10] annual industry reports,[11] government and corporate websites,[12–19] and personal communications. The facilities include 310 coal gasification-based ammonia plants, 84 coal-to-methanol plants, 3 coal to FTL plants, and 1 direct-coal-liquefaction plant.** Cumulatively the estimated emissions from all of these plants is some 270 million tonnes of CO_2 per year. Table 1 shows the distribution of plant sizes: 12 NH_3 plants and 45 planned or under-construction coal to methanol or coal to liquids plants are of mega-scale in terms of annual CO_2 emissions. We have mapped all sources assuming (to simplify identification of where the plant is approximately located) that each is at the center of the city near where it is actually located (Fig. 2).

3. CO_2 sinks in China

Some recent research has focused on estimating potential CO_2 storage capacity in China, including in oil fields, gas fields, deep saline formations and unmineable coal seams, as summarized in Table 2. There are significant variations among different estimates, reflecting the preliminary nature of the estimates due to lack of detailed geological data.

‡ In 2007, China produced nearly 42 million tonnes of nitrogen contained in ammonia fertilizer.[5] More than 60% of all ammonia production capacity (as of 2006[6]) was based on coal gasification. The remaining capacity was based on use of natural gas or oil residues. Less pure CO_2 is emitted from natural gas-fed ammonia plants compared with coal-fed plants.

§ CO_2 can be separated from gaseous mixtures using a variety of processes. Processes that absorb CO_2 in a physical solvent are favored for removal when the mixture is available at elevated pressures. Differences in the solubility of different gases under different temperature and/or pressure conditions help determine the choice of the solvent to be used in such cases. Two common solvents are Rectisol (chilled methanol) and Selexol [dimethyl ethers of poly(ethylene glycol)]. Typically, large coal-to-chemicals or fuels projects adopt Rectisol-type technology. Smaller projects tend to use the Selexol-type technology.

¶ The EF for an ammonia plant depends slightly on the gasification technology used. Meng *et al.*[3] indicate 3.16 tonnes CO_2/tonne NH_3 for ammonia plants using a Texaco (GE) gasifer and 3.34 tonnes CO_2/tonne NH_3 with a Shell gasifer. The International Energy Agency uses 3.8 tonnes CO_2/tonne NH_3 regardless of gasifer design.[7] Since, as Meng *et al.* have shown, differences in EF among gasifier types are small, we assume for simplicity the same EF for all plants, regardless of design. Our EF estimate is from a feasibility study for a Chinese coal-to-ammonia plant using a Shell gasifer.[8]

‖ This emission factor for direct coal liquefaction plants is based on discussions with Ren Xiangkun, Shenhua Coal to Liquid Group (Sept. 2009). Most of the CO_2 streams are from the gasification-based production of the H_2 used to liquefy coal and hydrogenate the raw oil in the direct-coal-liquefaction plant.

** Nearly all of the ammonia plants in this study (306 out of 310) are operating plants. Most of the coal-to-methanol plants (84 out of 88) and all of the coal-to-liquids plants are at different phases of construction. Plants producing chemicals/fuels other than ammonia, methanol, and hydrocarbon fuels are not included in our analysis.

Table 1 Size distribution of CO_2 emissions from coal-to-chemicals and coal-to-synfuels plants in China

Type of facilities	Net CO_2 streams per facility (million tonnes CO_2 /year)	Number of facilities	Total net CO_2 streams (million tonnes CO_2 /year)
Ammonia[a]	<0.5	276	45.0
	0.5–1.0	22	15.4
	>1.0	12	14.7
	subtotal	310	75.1
Coal-to-methanol[b]	<0.5	22	7.2
	0.5–1.0	19	15.9
	>1.0	43	149
	subtotal	84	172.1
Coal to liquids[bc]	<0.5	0	0
	0.5–1.0	2	1.5
	>1.0	2	21.8
	subtotal	4	23.3
Totals		**398**	**270.5**

[a] At NH_3 plants, some captured CO_2 is used for urea production. The CO_2 stream estimates here are net of CO_2 use for urea production. CO_2 consumption for urea production is calculated assuming a consumption factor of 0.73 kilotonnnes CO_2/kilotonne urea.[3] Urea production data are available for NH_3 plants for which annual CO_2 emissions are greater than 1.0 Megatonnes. For other NH_3 plants, urea production is estimated using stoichiometric relationships, based on the assumption that all NH_3 would be used to synthesize urea at a rate of 1.76 tonnes urea/tonne NH_3.[3] Additionally, some of these plants co-produce methanol. CO_2 streams associated with methanol production are considered in the totals. [b] For coal-to-methanol and coal-to-FTL plants, the calculations are based on estimated production once all phases of the plant are operating. (Plants are often built in phases, with the first phase tending to involve a much smaller output than after all phases are complete.) [c] The National Development and Reform Commission has approved only two large-scale coal-to-liquids projects: the Shenhua direct-coal-liquefaction project in Inner Mongolia (approved for operation) and the Shenhua Ningdong Fischer–Tropsch project in Ningxia Province (approved for feasibility study).[20]

The most recently published estimates cited in our study are by Li, *et al.*[21] They estimate a total capacity of 4.8 gigatonnes (Gt) of CO_2 storage potential for oil fields, 5.2 Gt of CO_2 for gas fields, and about 12 Gt of CO_2 for unmineable coal seams. These are all relatively small capacities considering that China's total CO_2 emissions from fossil fuel use today is about 6 Gt/year. But Li *et al.*[21] have also estimated that the capacity in deep saline aquifers may be over 3 teratonnes (Tt) of CO_2, of which about 75% (2.3 Tt of CO_2) is in onshore formations and 25% (0.78 Tt of CO_2) is in offshore formations below the sea bed. Fig. 3 shows the distribution of these potential CO_2 storage reservoirs in China.

Estimates of saline aquifer storage capacity made by Li *et al.*[21] are a factor of twenty larger than estimates published in a paper with the same lead author two years earlier.[22] These two papers use the same estimation methodology. The wide gap between the two estimates can be largely explained by the difference in the value of one key parameter in the analyses. For the earlier paper the authors assumed that the ratio of the area of deep saline formations to the total area of all sedimentary formations is 0.01.[22] For the later paper, it seems that it is assumed that this ratio is 1.

In both cases, the approach was to estimate the volume of brine contained in each sedimentary basin in China and how much CO_2 could physically be dissolved in this brine (Box 2). In actuality, the amount of CO_2 that will dissolve in a brine is relatively small (less than 0.020 tonnes of CO_2 per tonne of brine under a range of brine salt concentrations[26]), which would suggest that Li *et al.*'s estimates are conservative, since some injected CO_2 could be trapped by mechanisms other than dissolution.[1] In fact, other mechanisms, notably storage of CO_2 in a separate phase as a dense supercritical fluid, will come into play because CO_2 would typically be injected into a formation

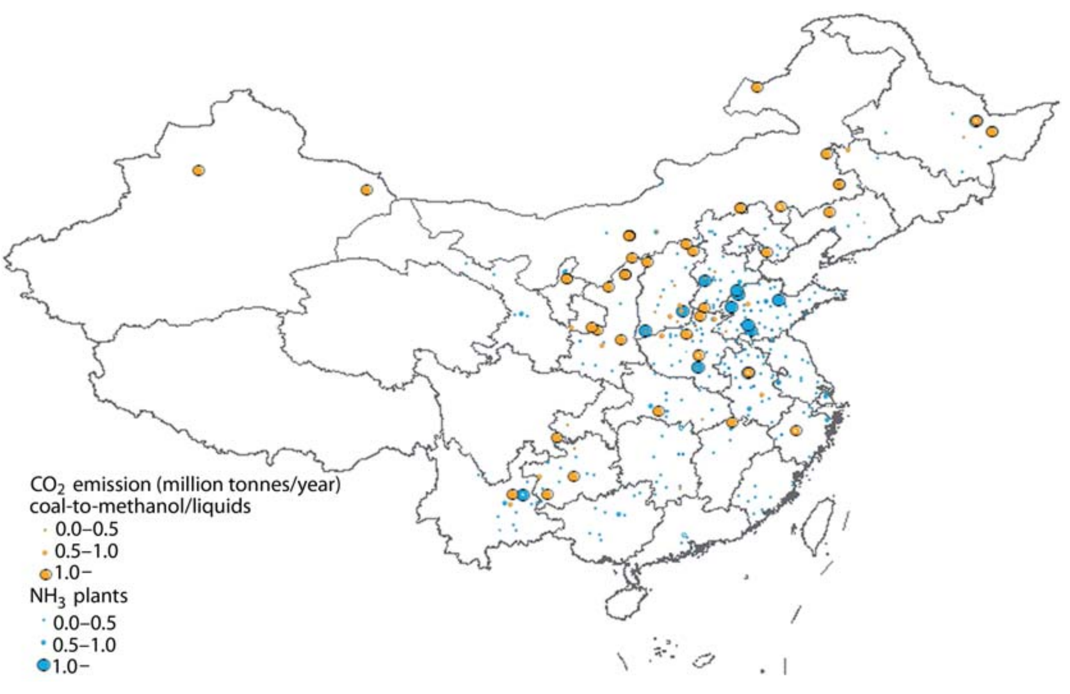

Fig. 2 Locations of nearly 400 existing and potential pure CO_2 streams in China.

Table 2 Estimates of CO_2 storage capacity in China

Source of Estimate	Estimated capacity in saline formations (Gt CO_2)	Estimated capacity in oil fields (Gt CO_2)	Estimated capacity in gas fields (Gt CO_2)	Estimated capacity in unmineable coalbeds (Gt CO_2)
X. Li, *et al.* (2008)[21]	3160 (total) 2380 (onshore)	4.8 (total) 4.6 (onshore)	5.18 (total) 4.28 (onshore)	12.0 (total) 12.0 (onshore)
X. Li, *et al.* (2006)[22]	143.5 (total) 77.38 (onshore)			
Y. Liu, *et al.* (2006)[23]			30.48 (total) 23.80 (onshore)	
Y. Liu, *et al.* (2005)[24]				12.78 (total)
H. Yu. (2005)[25]				141.7 (total)

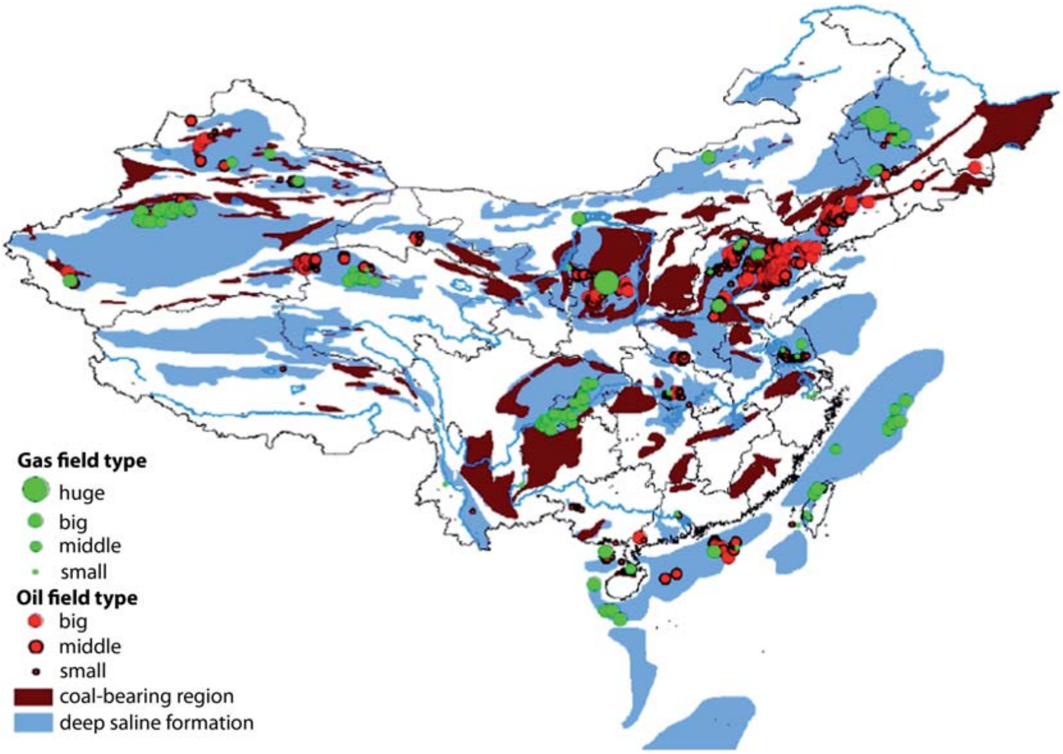

Fig. 3 Possible CO_2 storage sites in China.[21]

faster than it can be dissolved in the brine. For CO_2 storage in a separate supercritical phase, cap rock seals are needed to prevent escape. Because of the lack of empirical data, Li's analyses[21,22] did not consider the presence or absence of seals. Li and colleagues continue to be engaged in work to refine their capacity estimates to better account for such factors.†† Ultimately detailed reservoir assessments are needed to determine more accurately the storage capacity of saline formations in China.

4. CO_2 source-sink matching to identify early CCS project opportunities in China

Here we combine the forgoing analysis of CO_2 sources and potential sinks to make a preliminary identification of candidate projects in China for early CCS demonstrations. We limit our consideration of sources only to facilities which have CO_2 emissions of at least one million tonnes per year. This results in a total of 27 candidate CO_2-emitting facilities (Appendix A) distributed among five regions of China: Huabei, Ordos, Dongbei, Yuwan, and Xinjiang.

For the purpose of estimating the distance between CO_2 sources and potential sinks (and thereby the cost of transporting the CO_2), we superimpose the locations of these 27 facilities onto maps of sedimentary basins in each of the five regions. The maps of sedimentary basins are from Li and Lv.[27] Consistent with Li *et al.*'s estimates of saline aquifer storage capacities, we assume that suitable sedimentary layers for CO_2 storage exist in each sedimentary basin. Of course this assumptions must be verified *via* detailed basin assessments. We also estimate distances from CO_2 sources to oil fields, considering the possibility for CO_2 injection/storage *via* enhanced oil recovery (EOR).

†† Li, personal communication, April 2009.

Box 2: methodology applied to CO_2 storage capacity estimation

This box shows how Li *et al.* estimated the CO_2 storage capacity of deep saline formation (DSFs) in China in two different papers. In the earlier paper,[22] Li *et al.* estimated the storage capacity of a given reservoir (grams CO_2) as:

$$S_{CO_2} = A \cdot AR \cdot h \cdot TR \cdot p \cdot molS \cdot r \cdot M$$

Where,

A = horizontal area of the full sedimentary formation (m^2);
AR = area ratio (area of DSF to area of full formation);
h = average thickness of full formation (m);
TR = thickness ratio (thickness of layer in which CO_2 will be stored to thickness of total formation);
p = average porosity of sediment in DSF;
$molS$ = molar solubility of CO_2 in DSFs (mol kg^{-1});
r = density of CO_2-saturated brine at the depth of the DSFs (kg m^{-3});
M = molar mass of CO_2 (44 g mol^{-1}).

In the later paper[21] the authors estimate storage capacity of a given reservoir (grams CO_2) as:

$$S_{CO_2} = A \cdot h \cdot p \cdot massS$$

Where,

A = horizontal area of the formation in which CO_2 is to be stored (m^2);
h = average thickness of sediment layer in which CO_2 would be stored (m);
p = average porosity of sediment layer;
$massS$ = solubility of CO_2 in brine (g m^{-3}) at depth.

Table 3 Regional estimates of CO_2 storage capacity and number of CO_2 sources within the indicated distance from potential storage site

Region	Estimated CO_2 storage capacity (10^9 tonnes)[a]		Total no. mega-scale CO_2 sources in region	Number of mega-scale CO_2 sources: Distance/km to onshore saline aquifers				Distance/km to onshore oil fields			
	Aquifers	Oil fields		<50	50–100	100–150	>150	<50	50–100	100–150	>150
Huabei	262[b]	1.9	9	6	2	1	0	1	2	2	4
Ordos	257	0.36	9	9	0	0	0	1	0	1	7
Dongbei	358[c]	1.6	5	4	1	0	0	0	0	0	5
Yuwan	186[d]	0.065	2	2	0	0	0	0	0	0	2
Xinjiang	997[e]	0.39	2	2	0	0	0	0	0	0	2
TOTALS	2,060	4.3	27	23	3	1	0	2	2	3	20

[a] Capacity estimates are from Li *et al.*[21] [b] Of this total, 233 Gt are estimated to be in the Bohai Basin and 29 Gt in the Qinshui Basin. [c] Saline formation storage estimates: 228 Gt in Songliao Basin, 85 Gt in Erlian Basin, and 45 Gt in Sanjiang Basin. [d] Estimate of 178 Gt in South Huabei (Hehuai) Basin and 7.5 Gt in Nanxiang Basin. [e] Saline formation storage estimates: 746 Gt in Tarim Basin, 197 Gt in Zhunggar Basin, and 54 Gt in Tu-Ha Basin. Oil field storage estimates: 0.069 Gt in Tarim fields, 0.20 Gt in Zhunggar fields, and 0.12 Gt in Tu-Ha fields.

In each of the five regional maps that we show below (Fig. 4–8), we show concentric zones around each of the 27 CO_2 sources at radii of 50, 100 and 150 km, on the basis of which we can estimate the straight-line distance between each CO_2 source and the nearest potential aquifer sink or oil field sink.

Table 3 summarizes the source-sink matching results gleaned from Fig. 4–8. (See Appendix B for details.) The majority of the candidate CO_2 sources are found in the Ordos, Huabei and Dongbei regions. Considering all five regions, most of the CO_2 sources (23 out of 27) are located within 50 km of a deep saline formation potentially suitable for storing CO_2. Most of the CO_2 sources (20 out of 27) are located more than 150 km from an oil field, although there are two facilities within 50 km and a total of seven within 150 km of oil fields.

5. Cost estimates for CCS projects in China

5.1. Cost models

The cost of CO_2 capture and storage will constitute a large percentage of the total cost of any CCS demonstration project. Using CO_2 from coal-to-chemicals or coal-to-fuels facilities can help minimize costs for such demonstration projects.

As discussed in Section 2, a coal-to-chemicals or coal-to-fuels facility generates an essentially pure stream of by-product CO_2 as an inherent part of the process of manufacturing the chemicals or the fuels, so that the added cost for capturing and storing CO_2 from one of these plants is much less than these costs for CO_2 from a coal-fired power plant.[4] The capture cost for one of these

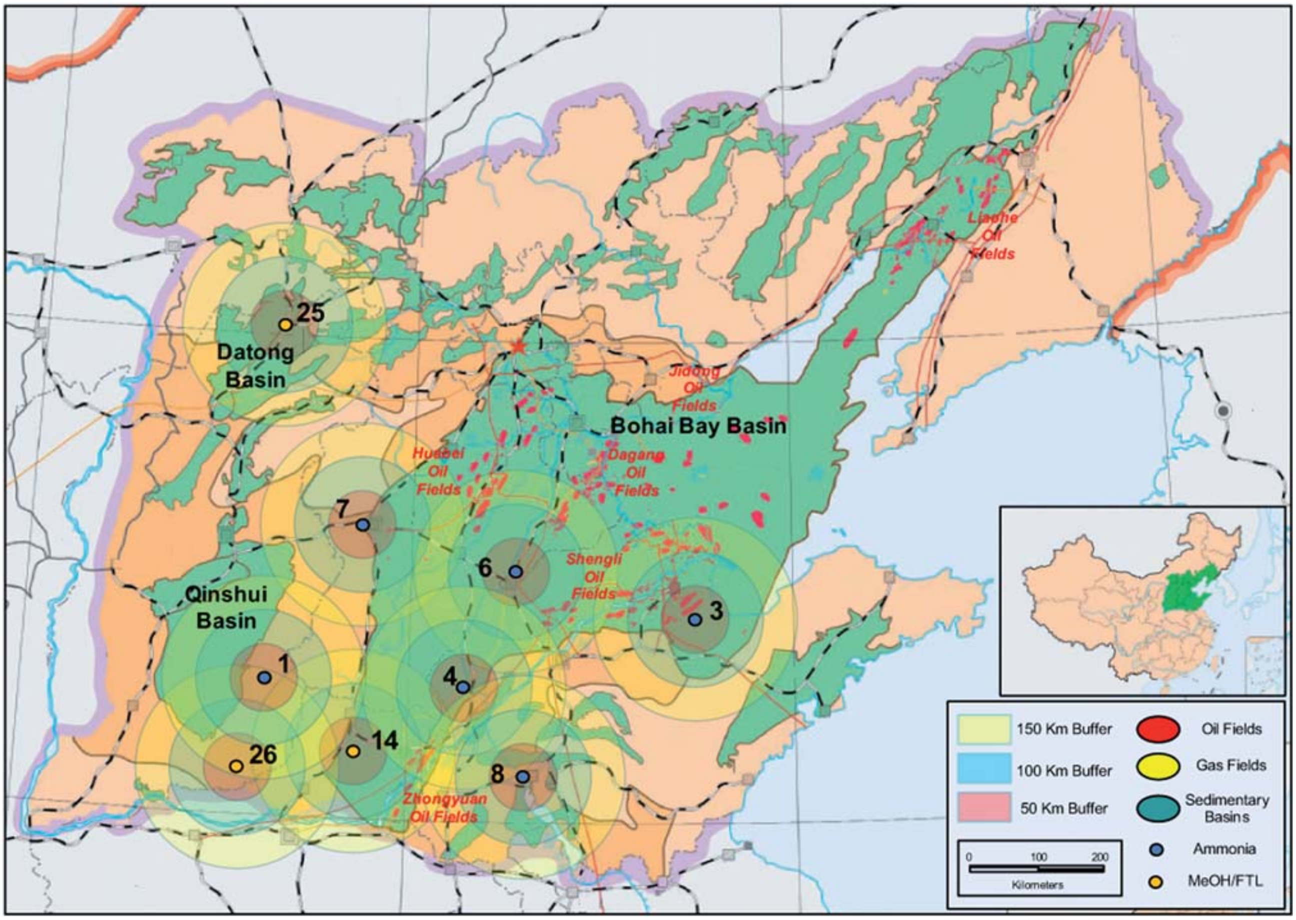

Fig. 4 Mega-CO_2 sources and potential sinks in the Huabei Region. Numbers refer to specific CO_2 stream sources (see Appendix A).

plants is essentially the (relatively modest) cost of compressing CO_2 to the pressure required for pipeline transport to the CO_2 storage site.

Here we estimate costs for CO_2 capture, transport, and storage for each of the 27 source-sink pairs identified previously in this paper as candidates for early demonstration projects. Our estimates assume "N^{th} plant" CCS systems. That is, we do not consider any cost or risk premiums that might be involved in deploying and operating CCS systems before a CCS industry has been commercially established. Our estimates can thus be considered to represent the commercial costs for CCS. We assume that the already-concentrated stream of CO_2 at a given facility is first compressed to 150 bar, then sent *via* a pipeline sized to the CO_2 flow rate of the facility to the nearest storage site where it is injected underground *via* one or more injection wells.

For capital and total levelized cost estimates, we adapt two alternative cost models from the literature to provide a range of illustrative costs for CO_2 transport and storage. In conjunction with the use of each model (referred to here as Model A, based on McCollum and Ogden,[28] and Model B, based on McCoy[29]), compressor costs are estimated as in Kreutz *et al.*[4] These models were developed for US applications. To account for lower construction and operating costs in China *versus* the US , we apply a local-factor multiplier of 0.8 to US-based capital costs and 0.6 to US-based operating and maintenance (O&M) costs.‡‡ The capital cost multiplier is at the high end of the multiplier range (0.31 to 0.84) identified by Huang *et al.*[30,31] for components of coal gasification-based power generation systems. The transport and injection models, as they originally appeared in the literature, are described in Box 3.§§ For Model A and Model B, we escalated capital cost estimates to 2007 US$ using the Chemical Engineering Plant Cost Index.[32] For all cases we assume a plant capacity factor of 90% and an annual capital charge rate of 15% (corresponding to a discount rate of 8.5%/year and a 10-year amortization period).

In both of our models, the value of several parameters can have important influences on the estimated costs of CO_2 stored. These parameters include:

• the pressure at which the concentrated CO_2 is available for capture at the source facility,

‡‡ Michael Desmond, BP, personal communication, February 2009.

§§ Both of the original models include costs for boost compression along the length of the pipeline and boost compression at the injection point. Our calculations assume compression to 150 bar at the plant gate, which obviates the need for boost compressors in the pipeline or at the injection point. We have adjusted the original models accordingly.

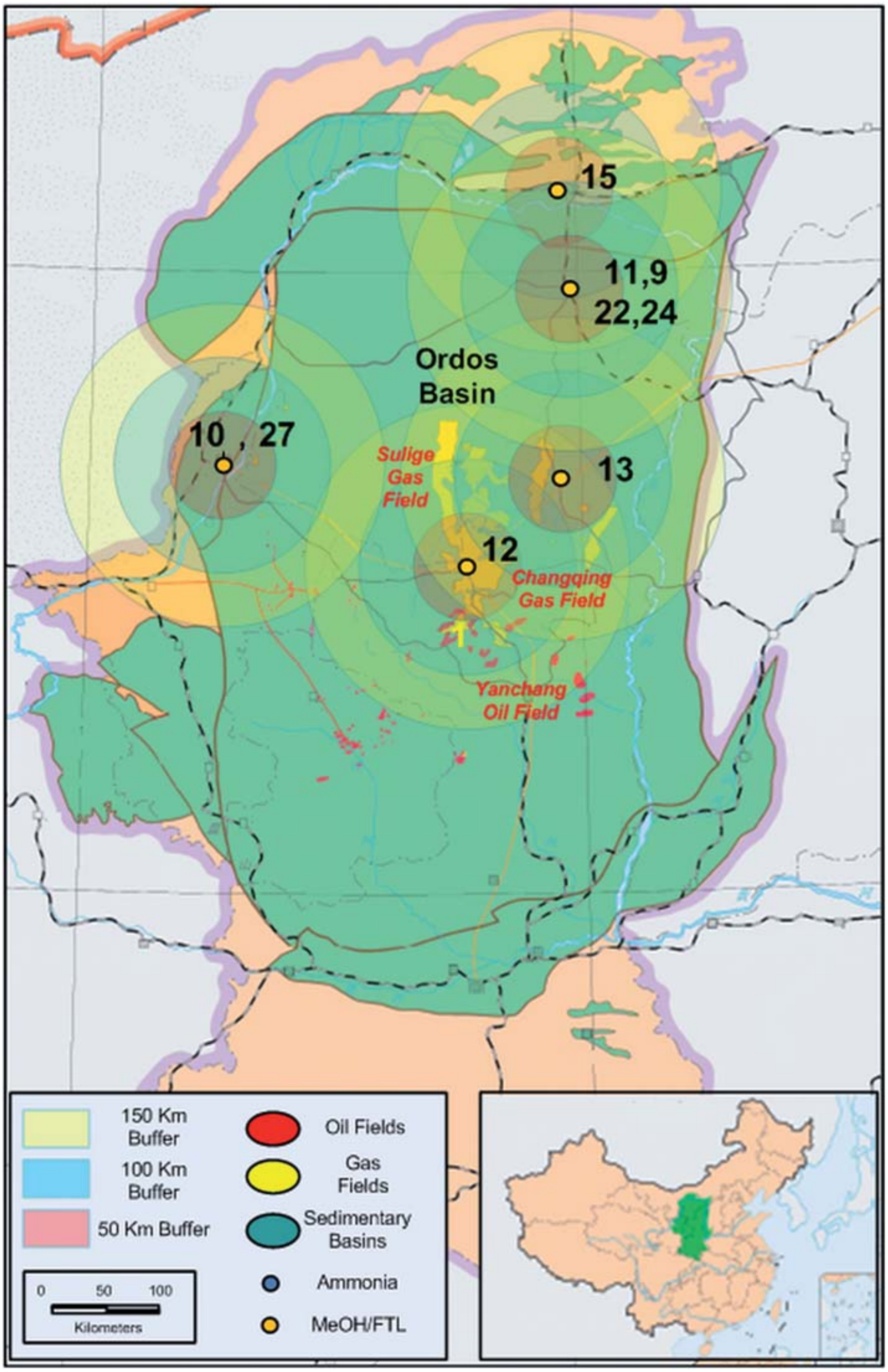

Fig. 5 Mega-CO_2 sources and potential sinks in the Ordos Region. Numbers refer to specific CO_2 stream sources (see Appendix A).

• the price paid for electricity to run the CO_2 compressor at the source facility,

• the flow rate of the captured CO_2,

• the length of the CO_2 pipeline between the source and where it is injected underground,

• the injectivity (the maximum rate at which CO_2 can be injected into a single well),

• the depth of the sedimentary layer in which CO_2 is to be stored.

The influence of these parameters on CO_2 compression, transport, and storage costs (in all cases including capital expenditures, operation and maintenance, and purchased electricity costs) are illustrated in Fig. 9, 10, and 11, respectively.

In the scale range of interest for mega-CCS projects (> 1 million tonnes/year CO_2 flow), scale has only a minor impact on compression cost, but the pressure from which the CO_2 is compressed (which varies with the specific system design for CO_2 capture) has a much larger impact (Fig. 9a). For reference,

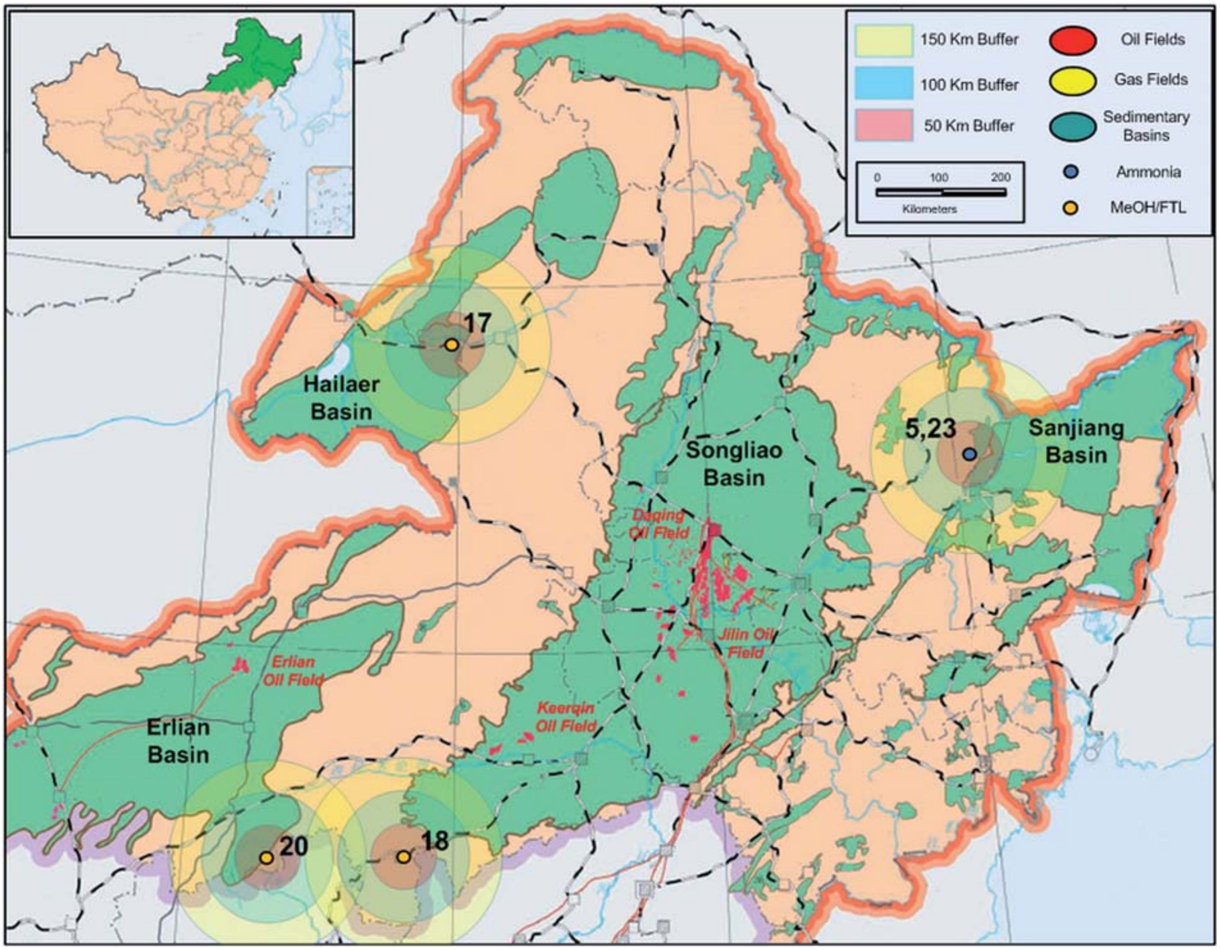

Fig. 6 Mega-CO_2 sources and potential sinks in the Dongbei Region. Numbers refer to specific CO_2 stream sources (see Appendix A).

a typical coal-NH_3 production facility using Rectisol® CO_2 capture technology in China will have CO_2 available at an average pressure of about 1.6 bar.¶¶ Likewise, the electricity purchase price has a significant impact on compression cost (Fig. 9b). For reference, the average electricity price to common industrial consumers in China was $92/MWh (US$) in 2008.

Both the annual CO_2 storage rate and the distance transported from source to underground injection point affect the unit CO_2 cost of pipeline transport (Fig. 10). CO_2 transport costs estimated using Model B are significantly lower than those estimated using Model A, ranging from about $1.5/tonne CO_2 in Model B to $2.5/tonne CO_2 in Model A at a scale of one million tonnes per CO_2/year for a 50 km pipeline length. For both models, unit CO_2 cost declines with the CO_2 flow rate, but the influence of scale diminishes with increasing flow rate.

For a fixed total flow rate of CO_2 into a saline formation, the cost of injection and storage is a function of the injectivity (maximum injection rate per well), the well depth, and the annual rate of storage for the system (Fig. 11). Model B predicts higher costs than Model A and shows a higher sensitivity to the annual rate of CO_2 injection. Injection and storage costs increase as well injectivity decreases, and they rise especially sharply at injectivities less than about 1000 tonnes of CO_2/well/day (Fig. 11a). Costs also increase with increasing well depth (Fig. 11b).

5.2. Cost estimates for early CCS projects in China

On the basis of the above analysis of component-level costs for CCS, we now estimate upper and lower bound total costs for generic CCS projects, as well as for projects involving each of the 27 potential source-sink pairs identified earlier.

For estimating upper and lower bounds, we define three sets of parameter values: low-cost, base-cost, and high-cost (Table 4). The lower-cost projects are characterized by higher annual storage rates (which provides capital cost scale economies in compressor and pipeline costs), shallower injection depths (which reduce well drilling costs), higher injectivities (which reduce the number of wells needed for injecting a given annual amount of CO_2), and higher starting pressures for CO_2 compression (which reduce electricity purchase requirements).

¶¶ This is an estimate based on discussions with experts in China. It is supported by an estimate in the literature[4] indicating that 1/3 of the CO_2 captured by a Rectisol® system can be made available at 3 bar, with the remainder available at 1.2 bar, or a weighted average of 1.8 bar for the full CO_2 stream.

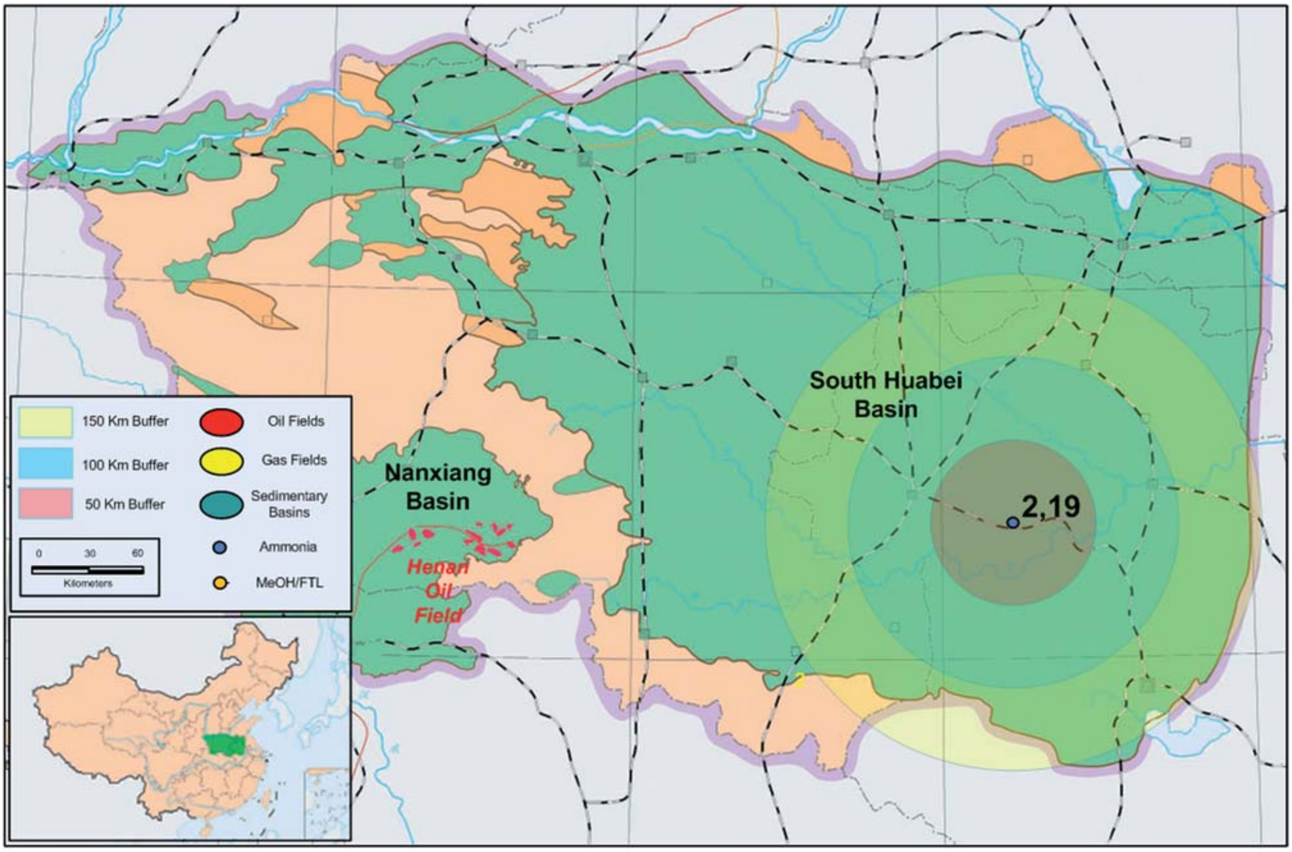

Fig. 7 Mega-CO_2 sources and potential sinks in the Yuwan Region. Numbers refer to specific CO_2 stream sources (see Appendix A).

Fig. 12 shows the total costs for CCS estimated for the low-cost, base-cost, and high-cost set of parameter values for both Model A and Model B, as a function of the distance between CO_2 source and sink. For the base-cost set of parameter values, Model A and Model B give results that are relatively close to each other but diverge as the source–sink distance grows. At a 50 km distance, both models indicate a total CCS cost of about \$12/tCO_2; but at 200 km, the CO_2 cost per tonne ranges from \$17 for Model A to \$22 for Model B. The estimates for the low-cost and high-cost cases are about \$6/tCO_2 and \$14/tCO_2 at 50 km, and about \$8/tCO_2 and \$33/tCO_2 at 200 km, respectively.

It is also of interest to compare specific CCS cost estimates (in \$ per tonne of CO_2) for US pricing *vs.* Chinese pricing. Fig. 13 shows that specific costs differ very little between the US and China. The slight differences reflect the relative costs of capital and O&M on the one hand (which are lower in China) and electricity prices for common industrial users on the other hand (which are lower in the US). In the low-cost and base-cost cases, CO_2 compression dominates the total cost, and electricity purchases account for more than 80% of the total compression cost. As a result, the lower capital and O&M costs in China relative to the US are largely offset by the higher prices paid for electricity in China. But for the high-cost case, transport and storage costs dominate, so that total specific costs are slightly higher in the US than in China. Thus on a specific cost basis, there is very little difference in the overall economics between projects sited in the US and projects sited in China.

The key difference between the US and the Chinese situations is that there are more project opportunities in China compared to the US—*i.e.*, there are very few existing and planned projects in the US that are characterized by low CO_2 capture costs.

Fig. 14 presents cost estimates for the 27 candidate source–sink projects using base-cost assumptions. For this preliminary analysis, the pipeline distance for each potential project was assigned to one of four distance ranges (10 km, 50 km, 100 km, 150 km) based on the source–sink maps shown earlier; in-depth project-specific studies would be required for any potential demonstration project to develop more accurate cost estimates. Project-specific issues such as location of railways, highways, rivers, cities, mountains, and suitable injection sites could result in total costs that differ from the cost estimates presented here.

Fig. 14 presents summary preliminary cost estimates for 27 projects. For these estimates, we have assumed the base-cost values for injectivity and initial CO_2 pressure (Table 4). For the injection well depth, we have assumed the average depth of existing oil/gas wells in each selected basin, based on Li and Lv.[27] (see Appendix C). Our assumed base-cost injectivity (3000 tonnes of CO_2/day/well for each project) enables all CO_2 in a project to be injected *via* a single well in most cases.

Eighteen of the projects have saline aquifers within 10 km of the source, so that total CCS costs are 9.0 to 12.6 \$/tonne

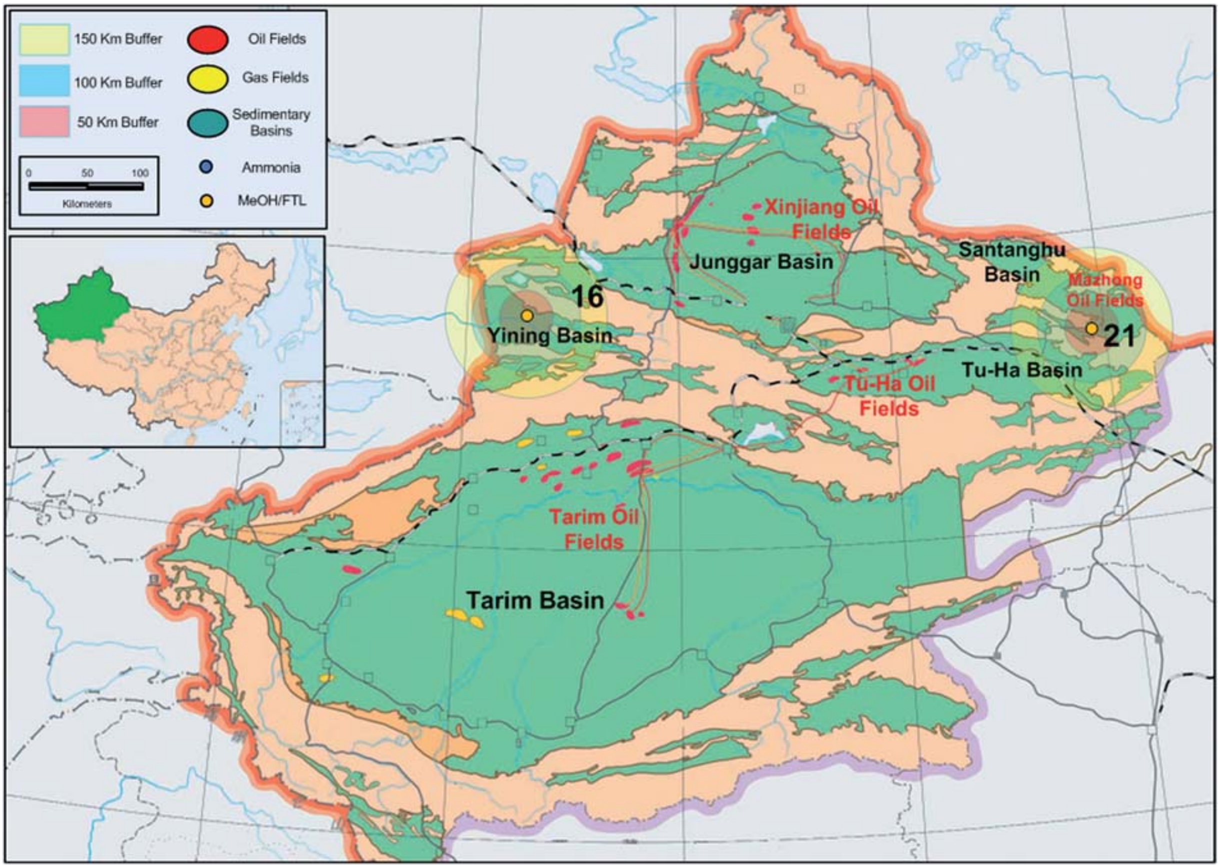

Fig. 8 Mega-CO_2 sources and potential sinks in the Xinjiang Region. Numbers refer to specific CO_2 stream sources (see Appendix A).

CO_2. As detailed in Appendix C, compression accounts for most of the cost in these cases. The 10-year net present value (NPV) cost of these projects (using Model B and a discount rate of 8.5%) ranges from \$88.5 million for the project with one of the smallest annual CO_2 storage rates (1.08 million tonnes of CO_2/year) to \$1.15 billion for the project with the largest storage rate (19. 0 million tonnes of CO_2/year). Another five projects are within 50 km of a saline aquifer. The additional pipeline distance adds about 1 \$/tonnes CO_2 to the transportation costs. Three more projects are within 100 km, and 1 project is within 150 km of an aquifer. For each of these last nine projects, the NPV project costs range from \$92.3 to \$209.4 million, and the levelized cost for CO_2 capture and storage ranges from \$10.8/tonne of CO_2 to \$17.0/tonne of CO_2 (Appendix C).

6. Summary and conclusions

This paper has analyzed potential near-term opportunities for mega-scale CCS demonstration projects that might be undertaken in China at relatively low costs by exploiting the unique fact that China has hundreds of existing and planned coal conversion plants that emit pure CO_2 streams to the atmosphere as a normal part of their production processes. By-product CO_2 at some of these plants might be considered as CO_2 sources for CCS demonstration projects. The cost of capturing this CO_2 would be much lower than the cost of retrofitting an operating coal-fired power plant to capture its CO_2 emissions or the cost of CO_2 capture designed into a new coal-fired power plant.

For the analysis in this paper, a database of low-cost industrial coal-derived CO_2 sources in China was built, including 310 operating plants producing NH_3 (75.1 million tonnes CO_2/year total estimated emissions) and 88 plants at different phases of construction for methanol or liquid hydrocarbon fuels production (195.4 million tonnes of CO_2 emissions per year, once all are operating). Of the 398 industrial CO_2 sources the 27 largest of the currently operating, being constructed, or planned facilities (each having emissions of more than one million tonnes CO_2/year) were selected for further analysis.

Potential CO_2 sinks were identified through literature review and discussion with geological experts in China. However, detailed assessment of these reservoirs is needed to gain confidence that they are indeed suitable for storage. In particular, “bottom-up” estimates of geological storage capacity and estimated costs of storage in different reservoirs are needed. Such an assessment for the US, to be carried out by 2012/2013, is authorized in the Waxman/Markey legislation that was passed by the US Congress' House of Representatives in 2009.

Box 3: The US economic models for CCS cost estimation

CO_2 compression cost estimation model

Cost type	Unit	Cost from [ref. 4] ($2007), used with both Model A and Model B
Capital_Compressor	*$*	$6\,310\,000 \times 132\% \times (W_{comp}/10)^{0.67}$
Capital_Pump	*$*	$9\,520\,000 \times 132\% \times (W_{pump}/13)^{0.67}$
Operation & maintenance (O&M)	*$/year*	*0.04 × Capital*
Electricity	*$/year*	$Pe \times (W_{comp} + W_{pump}) \times CF \times 24 \times 365$ (CF = capacity factor)

Units on compressor power "W_{comp}" and pump power "W_{pump}" are MW. Units for electricity price "*Pe*" are $/MWh.

Pipeline transportation cost estimation models

Cost type	Unit	Cost_Ogden Model ($2005), employed in Model A	Cost_McCoy Model ($2004), employed in Model B
Capital_Material	*$*		$10^{3.112} \times (L)^{0.901} \times (D)^{1.59}$
Capital_Labor	*$*	Total capital =	$10^{4.487} \times (L)^{0.82} \times (D)^{0.94}$
Capital_ROW	*$*	$9970 \times (m)^{0.35} \times (L)^{1.13} \times F_T$	$10^{3.95} \times (L)^{1.049} \times (D)^{0.403}$
Capital_Misc.	*$*		$10^{4.39} \times (L)^{0.783} \times (D)^{0.791}$
O&M	*$/year*	*0.025 × Capital*	*3250 × L*

Capital_ROW is the cost for pipeline right-of-way. F_T is the "terrain factor" (accounting for deviations from straight line), assumed to be 1.2 on average.[28] The CO_2 flow rate, *m*, is in units of tonnes/day. The units on pipeline length, *L*, are kilometers. The units on pipeline diameter *D* are inches.

Geologic storage cost estimation models

Cost type	Unit	Cost_Ogden Model ($2005), employed in Model A	Cost_McCoy Model ($2004), employed in Model B
Capital			
Initial site assessment	*$*	*1 857 773*	(100 000 × *area* + 3 000,000) × 130%
Injection equipment (drilling & completion)	*$/injection well*	$92916 \times \left(\frac{m}{280 \times \# \text{ of injection wells}}\right)^{0.5}$	$38\,931 \times e^{0.0000639 \times \text{well-depth}}$
Injection wells	*$/injection well*	$106\,300 \times e^{0.0008 \times \text{well-depth}}$	$70123 \times e^{0.00032 \times \text{well-depth}} \times \left(\frac{21}{\# \text{ of injection wells}}\right)^{0.5}$
Operation & maintenance (O&M)			
Fixed Expenses (fixed O&M)	*$/injection well/year*	*7596*	$29\,537 \times e^{0.000167 \times \text{well-depth}}$
Consumables (variable O&M)	*$/injection well/year*	*20 295*	
Surface maintenance (fixed O&M)	*$/injection well/year*	$15420 \times \left(\frac{m}{280 \times \# \text{ of injection wells}}\right)^{0.5}$	
Subsurface maintenance (Fixed O&M)	*$/injection well/year*	*5669/1219* × well-depth	
Monitoring, verification and closure costs	*$/tonne CO_2*		*0.02–0.08*

Model B was developed to estimate costs under central US conditions; the parameter, *area*, has units of square miles and 'well-depth' has units of feet. In model A, the CO_2 injection rate, *m*, is in metric tonnes/day, and 'well-depth' has units of feet.

Saline aquifer storage was emphasized in this study. The 27 largest CO_2 sources identified as potential candidates for CCS projects were mapped along with existing saline aquifers and oil fields to identify possible source–sink matches. Twenty-three of the source–sink pairs were less than 50 km apart. The Ordos Basin contains 9 candidate projects. The Huabei region contains a large number of NH_3 plants and also prospective aquifer and oil field storage sites.

Total costs for CCS projects were estimated on a preliminary basis using two cost models adapted from the literature. Our cost estimates assume "N^{th} plant" CCS systems. That is, we do not consider any cost or risk premiums that might be involved in deploying and operating CCS systems before a CCS industry has been commercially established. Our estimates can thus be considered to represent the commercial costs for CCS.

For 18 projects where the CO_2 source is within 10 km of a sink, the estimated total cost of CCS was between \$9.0/tonne of CO_2 and \$12.6/tonne of CO_2. The highest cost estimate among all 27 evaluated projects was less than \$21/tonne of CO_2. The NPV cost for the projects ranged from \$89 million to \$1.15 billion, but more than 75% of the project NPV costs are \$200 million or less.

Saline aquifers account for the largest fraction of total estimated geological storage capacity in China. It is highly

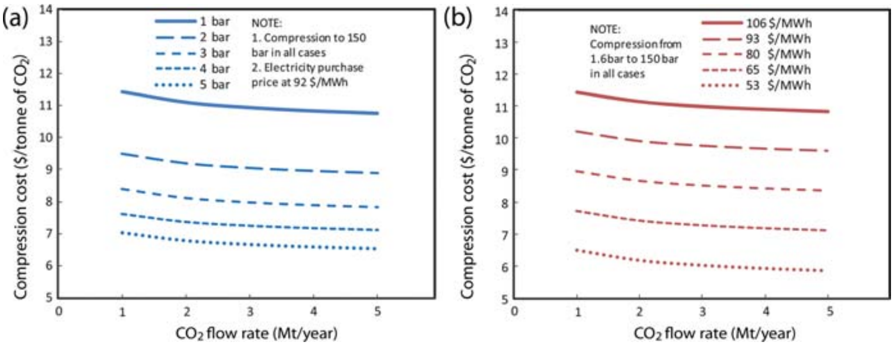

Fig. 9 Estimated cost for CO_2 compression in China using cost model described in Box 3, with adjustments for Chinese location (as discussed in text). (a) Shows the cost for different starting CO_2 pressures, (b) shows the cost for different electricity prices.

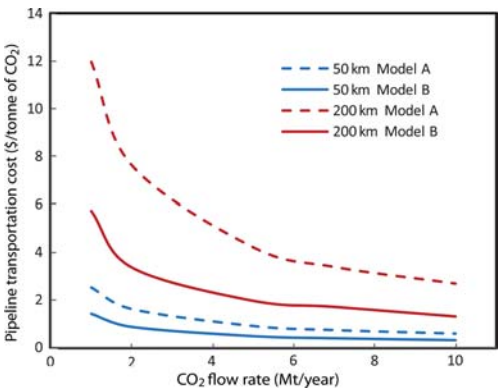

Fig. 10 Estimated cost for pipeline transport of pressurized CO_2 in China as a function of CO_2 flow and transport distance using the two cost models described in Box 3, with adjustments to location in China discussed in text.

desirable to ascertain the viability of CO_2 storage in saline aquifers, without which CCS will play only a minor role in mitigating the climate impact of coal use in China. So early projects to demonstrate CO_2 storage in such aquifers are important.

On the other hand, there is likely to be more industrial enthusiasm for carrying out CO_2 storage *via* EOR, since it is already utilized in some parts of the world and might generate attractive revenue streams from the sale of CO_2 to oil field operators. Because CO_2 EOR technology is not yet established in the market in China, government support for one or two commercial scale EOR projects is probably needed. Experience in such projects could lead to rapid learning about CCS technologies. Subsequent EOR projects would require government support mainly for monitoring, modeling, and verification that the net injected CO_2 (after repeated recycling) is securely stored underground—because revenues are likely to be fully adequate to cover costs.

Our analysis indicates that China is unique in the world as a prospective host for early CCS projects because of the large number of opportunities for projects that involve very low CO_2 capture costs. This suggests that there would be mutual value in international cooperation to support CCS demonstration projects in China, including international sharing of the total costs for such demonstrations. Also CO_2 EOR expertise in the

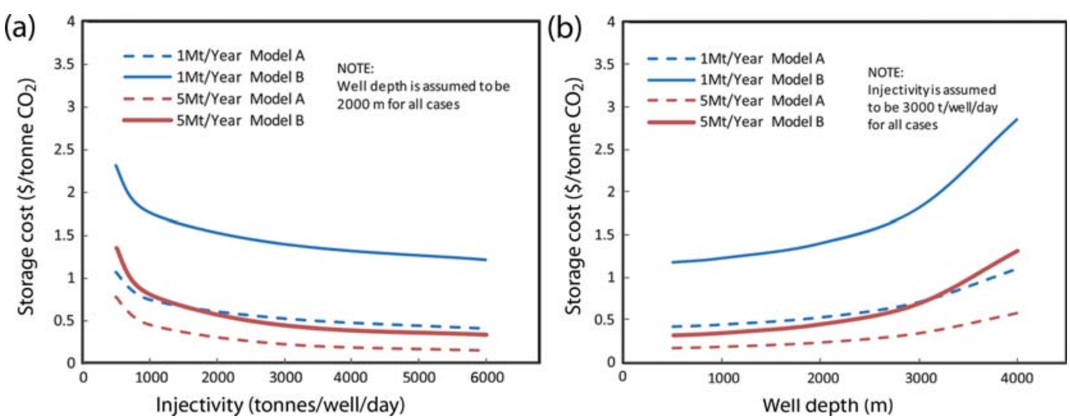

Fig. 11 Estimated cost for CO_2 injection and storage in saline formations in China using the cost model described in Box 3, with adjustments to location in China discussed in the text. (a) Shows cost as a function of injectivity at two levels of annual CO_2 storage, (b) shows cost as a function of well depth for two different levels of annual CO_2 storage.

Table 4 Parameter values for low-, base-, and high-cost CCS estimates

		Low	Base	High
Annual CO_2 Stored[a]	10^6 tonnes CO_2/year	5.0	1.0	1.0
Injection well depth [b]	Meters	1000	2000	3000
Injectivity[c]	Tonnes CO_2/well/day	6000	3000	500
CO_2 intial pressure	Bar	1.8	1.6	1.0
US electricity price[d]	\$/MWh	70	70	70
China electricity price[e]	\$/MWh	92	92	92

[a] Among the 27 CO_2 sources identified earlier, the largest stream is estimated to be 19.0 megatonnes (Mt) of CO_2/year (in Inner Mongolia, Ordos region) and the smallest 1.02 Mt of CO_2/year (in Shandong Province, Huabei region). [b] A minimum depth of 800 meters is required to ensure that the injected CO_2 stays in a dense (supercritical) phase. The estimates of Li *et al.*[22] of storage capacity in saline aquifers assumed reservoir depths from 1 to 3 km. [c] This range of assumed injectivities, based on discussions in June 2009 with Charles Christopher, is likely to be widely regarded by experts as realistic. Some comparisons: Meng *et al.*[3] assumed injectivities ranging from 1100 to 150 000 tonnes of CO_2/well/day for storage in saline aquifers. The estimated injection rate for the planned Gorgon CCS project in Australia is 10 000 tonnes CO_2/well/day.[1] The saline aquifer injection rate for the Sleipner CCS project is approximately 3000 tonnes of CO_2/well/day.[1] [d] The average retail price to industrial customers in the US in 2008 was \$70/MWh.[33] [e] The average electricity price paid by normal industries in China in 2007 was 693 RMB/MWh,[34] which we have converted to US\$ using the average 2007 exchange rate of 7.52 RMB/US\$.

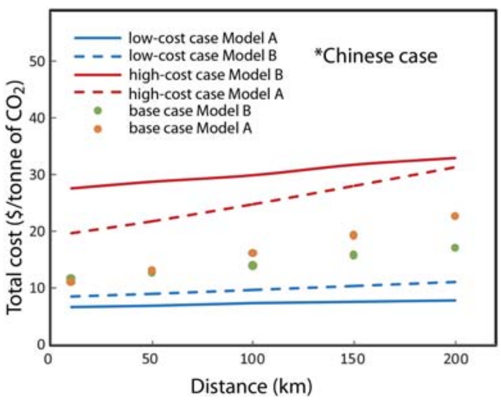

Fig. 12 Cost comparison for China based on the two models.

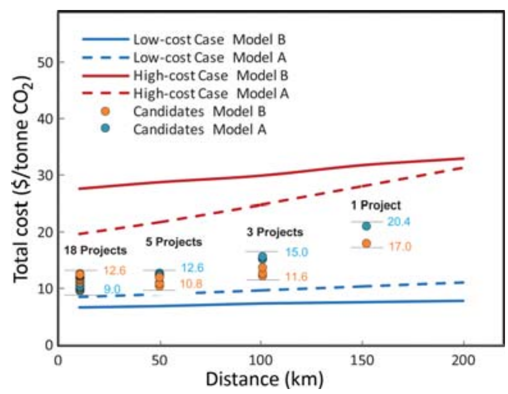

Fig. 14 Preliminary cost estimates for potential early saline aquifer storage CCS projects in China. See Appendix C.

US and other countries with CO_2 EOR experience might be transferred to help CO_2 EOR implementation in China's oil fields, and there is likely to be strong international interest in supporting monitoring, modeling, and CO_2 storage verification activities for CO_2 EOR projects, as well as for aquifer storage projects.

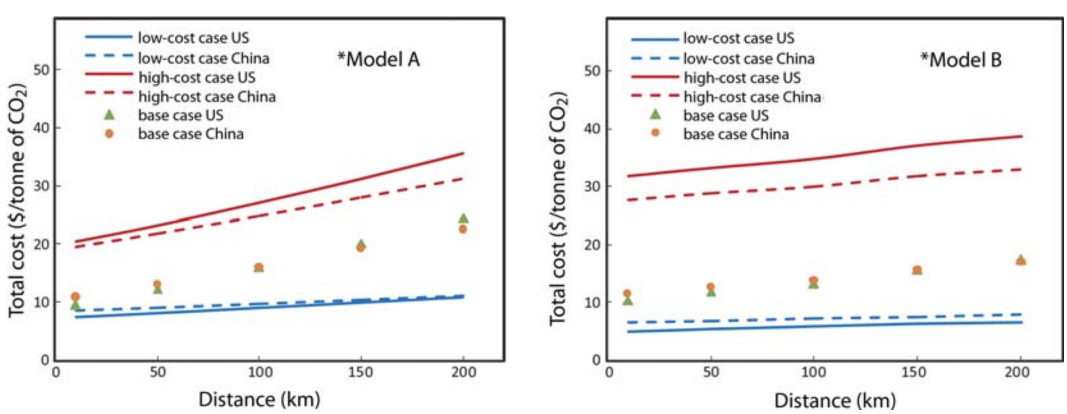

Fig. 13 Costs for Chinese and US pricing: Model A (left) and Model B (right).

Appendix A: potential mega-scale CO_2 sources for CCS demonstration projects in China

Plant Number	Company	Province	Plant Status[a]	Net CO_2 stream (kt/year)
1	Shanxi Tianji Coal-Chemical Fertilizer Plant	Shanxi	O	1470
2	Huaihua Corp Huainan Chemical General Plant	Anhui	O&C	1444[b]
3	Shandong Lianmeng Chemical Co., Ltd	Shandong	O	1419
4	Shandong Liaocheng Luxi Chemical Co., Ltd	Shandong	O	1207
5	Longmay Mining Group, Beitai Iron and Steel Group	Heilongjiang	C	1083
6	Shandong Hualu Hengsheng Chemical Co., Ltd	Shandong	O	1044
7	Hebei Zhengyuan Chemical Co., Ltd	Hebei	O	1025
8	Yankuang Yishan Chemical Co., Ltd	Shandong	O	1021
9	Shenhua Coal to Liquid Group	Inner Mongolia	C&P	2880
10	Shenhua Group, Sasol Synfuels International	Ningxia	P[c]	18960
11	Zhongtian Hechuang Energy Co., Ltd.	Inner Mongolia	P	6510
12	Yanchang Petroleum Group	Shaanxi	C&P	4650
13	Yankuang Group	Shaanxi	C&P	3565
14	Zhongyuan Dahua Group Co., Ltd, Hebi Coal Industry Group	Henan	C&P	2875
15	Zekai Group Corp.	Inner Mongolia	C	2790
16	Shandong Xinwen Mining Group Co., Ltd.	Xinjiang	P	2790
17	Huaneng Hulunbuir Energy Co., Ltd	Inner Mongolia	C&P	2790
18	Shenhua Group	Inner Mongolia	C	2790
19	Anhui Huainan Chemical Group	Anhui	C	2635
20	Datang International Power Genereation Co., Ltd	Inner Mongolia	C	2604
21	Datong Coal Mine Group Company	Shanxi	C	1860
22	HuaYi Group and Yili Resources	Inner Mongolia	P	1860
23	Hanneng Shuangyashan	Heilongjiang	P	1860
24	Jiutai Energy Group	Inner Mongolia	C	1860
25	Xinjiang Guanghui Industry Co., Ltd.	Xinjiang	C&P	1860
26	Shanxi Lanhua Coal Industry Group	Shanxi	C	1569
27	Shenhua Ningmei Group	Ningxia	O&C	1318

[a] O = operating; C = under construction; P = in planning; O&C = partially operating, partially under construction; C&P = initial phases under construction and remaining phases in planning. [b] The CO_2 stream from the same company's 600 kt/y coal-based MeOH plant at the same site has been added to the net CO_2 stream from it's NH_3 plant. [c] The National Development and Reform Commission (NDRC) has approved proceeding with a feasibility study for this facility (Ren Xiangkun, Shenhua, personal communication, September 2009).

Appendix B: estimated CO_2 transport distances to potential sinks by region

	Distance/km to onshore saline aquifers				Distance/km to onshore oil fields			
CO_2 Source #	<50	50–100	100–150	>150	<50	50–100	100–150	>150
Huabei Region								
6	✓					✓		
7	✓							✓
8			✓				✓	
14	✓					✓		
21	✓							✓
26		✓						✓
Ordos Region								
9	✓							✓
10	✓							✓
11	✓							✓
12	✓				✓			
13	✓						✓	
18	✓							✓
22	✓							✓
24	✓							✓
27	✓							✓
Dongbei Region								
5	✓							✓
17	✓							✓
18	✓							✓
20		✓						✓
23	✓							✓
Yuwan Region								
2	✓							✓
19	✓							✓
Xinjiang Region								
16	✓							✓
25	✓							✓

Appendix C1: Summary of preliminary cost estimates (2007 US$) for potential CCS projects in China[a]

			Specific Cost ($/t$CO_2$, Model B)					
Plant Number	Pipeline Distance/km	Well Depth/km	Capital	O&M	Electricity	Total	Capital Investment (million $)	NPV Cost (million $)[b]
4	10	2608	2.6	0.46	7.9	11.0	37.1	103
3	10	2608	2.9	0.50	7.9	11.3	35.1	114
6	10	2608	2.9	0.51	7.9	11.4	34.6	92
2	10	2010	3.2	0.55	7.9	11.7	32.2	112
5	10	1187	4.0	0.66	7.9	12.6	27.5	88
11	10	1438	1.2	0.25	7.9	9.4	59.3	409
12	10	1438	1.5	0.29	7.9	9.7	50.9	302
13	10	1438	1.8	0.34	7.9	10.1	45.3	239
14	10	2608	2.1	0.39	7.9	10.4	41.7	198
16	10	1714	2.1	0.38	7.9	10.4	40.7	193
19	10	2010	2.2	0.40	7.9	10.5	39.9	184
10	10	1438	0.87	0.21	7.9	9.0	137.	1149
9	10	1438	2.1	0.37	7.9	10.4	41.1	198
21	10	2608	2.8	0.48	7.9	11.2	34.5	137
22	10	1438	3.5	0.52	7.9	11.9	40.8	144
24	10	1438	2.8	0.48	7.9	11.2	34.5	137
25	10	2094	2.8	0.49	7.9	11.2	34.8	137
27	10	1438	3.5	0.59	7.9	12.0	29.8	103
7	50	2608	3.8	0.59	7.9	12.3	40.0	97
17	50	1368	2.5	0.41	7.9	10.9	46.9	199
18	50	1438	2.5	0.41	7.9	10.9	46.9	200
20	50	1181	2.7	0.43	7.9	11.0	45.7	188
23	50	1187	2.9	0.50	7.9	11.3	35.5	138
1	100	2608	4.1	0.56	7.9	12.6	52.4	134
15	100	1334	3.2	0.45	7.9	11.6	56.1	209
26	100	2608	5.2	0.69	7.9	13.8	48.4	137
8	150	2608	8.1	1.0	7.9	17.0	46.7	107

[a] For all cases the assumed injectivity is 3000 tonnes/well/day. [b] Assuming 10-year project life (starting in 2010) and 8.5% discount rate.

Appendix C2: Summary of cost estimation (2007 US$) for potential early CCS action projects in China

	Specific Cost ($/tonne of CO_2, Model A)				Specific Cost ($/tonne of CO_2, Model B)			
Plant number	Compression	Transport	Storage	Total	Compression	Transport	Storage	Total
1	10.2	3.4	0.22	13.8	10.2	1.7	0.64	12.6
2	10.7	0.31	0.27	11.3	10.7	0.23	0.81	11.7
3	10.4	0.27	0.25	10.9	10.4	0.19	0.72	11.3
4	10.2	0.21	0.18	10.6	10.2	0.16	0.63	11.0
5	11.3	0.38	0.34	12.0	11.3	0.25	1.1	12.6
6	10.4	0.28	0.26	11.0	10.4	0.20	0.75	11.4
7	10.5	1.8	0.28	12.6	10.5	1.0	0.80	12.3
8	11.4	8.5	0.44	20.4	11.4	4.3	1.3	17.0
9	9.8	0.20	0.14	10.2	9.8	0.15	0.42	10.4
10	8.9	0.06	0.07	9.0	8.9	0.03	0.12	9.0
11	9.1	0.12	0.11	9.3	9.1	0.08	0.24	9.4
12	9.3	0.15	0.12	9.6	9.3	0.09	0.29	9.7
13	9.6	0.18	0.15	9.9	9.6	0.1	0.38	10.1
14	9.8	0.2	0.47	10.2	9.8	0.12	0.47	10.4
15	9.8	2.8	0.15	12.8	9.8	1.3	0.43	11.6
16	9.8	0.21	0.15	10.2	9.8	0.13	0.44	10.4
17	9.8	1.3	0.15	11.3	9.8	0.61	0.43	10.9
18	9.8	1.3	0.15	11.3	9.8	0.61	0.43	10.9
19	9.9	0.22	0.17	10.3	9.9	0.13	0.48	10.5
20	9.9	1.3	0.15	11.4	9.9	0.65	0.45	11.0
21	10.4	0.27	0.21	10.8	10.4	0.19	0.63	11.2
22	10.4	1.7	0.21	12.2	10.4	0.92	0.63	11.9
23	10.4	0.27	0.25	10.9	10.4	0.23	0.72	11.3
24	10.4	0.27	0.21	10.8	10.4	0.19	0.63	11.2
25	10.4	0.27	0.23	10.9	10.4	0.19	0.67	11.2
26	10.6	4.1	0.29	15.0	10.6	2.3	0.85	13.8
27	10.9	0.34	0.29	11.6	10.9	0.21	0.89	12.0

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