CO_2 STORAGE IN DEPLETED GAS FIELDS

Technical Study

Report No. 2009/01

June 2009

INTERNATIONAL ENERGY AGENCY

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IEA Greenhouse Gas R&D Programme (IEA GHG), "CO_2 Storage in Depleted Gas Fields", 2009/01, June 2009.

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OVERVIEW

Background to the Study

The IEA Greenhouse Gas R&D Programme (IEA GHG) commissioned Pöyry Energy Consulting, in association with Element Energy and the British Geological Survey (BGS), to undertake a study of global CO_2 storage potential in depleted natural gas fields.

Three main CO_2 geological storage scenarios may currently be considered as technologically-advanced – deep saline formations, depleted oil fields as part of enhanced oil recovery (EOR) schemes, and depleted natural gas fields. Much attention is currently focussed on deep saline formations due to these providing the largest theoretical global storage resource (10,000Gt according to the 2004 IPPC Special Report), and on CO_2-EOR schemes due to the potential economic benefits. However, depleted gas fields offer significant advantages for CO_2 storage: proven capacity and sealing structures to give confidence in storage security; and the presence of existing infrastructure that may be suitable for re-use in storage operations. Whilst some technical challenges remain – for example, controlling the flow of injected CO_2 into de-pressurised formations where aquifer ingress is low or absent – storage in depleted gas fields could be regarded in some locations as an 'early' opportunity for large scale commercial storage. The southern North Sea provides an example of such a location, where a number of large fields are rapidly approaching exhaustion of recoverable natural gas reserves.

An earlier study by IEA GHG in 2000 had reported a global CO_2 storage capacity in depleted gas fields of 797Gt. The main aims of this study were to re-assess global storage capacity and also derive cost abatement curves for transport and storage.

Scope of Study

The initial specification required a desk-based study to:

1. Assess the future implications for CO_2 storage of future natural gas production trends, especially the potential future exploitation of fields with naturally-high CO_2 content;
2. Undertake a source-sink matching exercise, utilising the IEA GHG database on point source emissions and with due consideration to existing transport pipeline infrastructure. The specification specifically stated that ship transportation should not be considered;
3. Determine the potential role of enhanced gas recovery (CO_2-EGR) in CO_2 storage;
4. Develop an analytical screening process/tool for the selection of gas fields suitable for CO_2 storage, allowing ranking of opportunities and assessment of potential global CO_2 storage capacity;
5. Estimate CO_2 storage costs in depleted gas fields;
6. Provide a summary of opportunities around the world where CO_2 storage in depleted gas fields could be feasible from both technological and economic perspectives.

During the course of the study, regular progress meetings were held between Pöyry, Element Energy, BGS and IEA GHG. Discussions during the early stages of the project led to the following revisions to the scope of the study:

- Estimates of storage capacity derived from the study would be placed in the context of a resource classification scheme. The Carbon Sequestration Leadership Forum (CSLF) resource 'pyramid' (Figure 1) was chosen as the example to be used, although this was not to be reported as an endorsement above other similar classification schemes;
- The study would undertake only a brief review of issues concerning natural gas fields with high CO_2 content and CO_2-EGR (items 1 and 3 on the original scope), since the report authors considered these issues to have limited significance for the overall CO_2 global storage potential of gas fields; therefore project resources would be better deployed on storage capacity estimation and cost analysis;
- Re-use of existing pipelines would not be considered for the source-sink matching and costing elements of the study, since the suitability of such infrastructure would vary according to local factors;
- Similarly, site-specific geological factors such as caprock and well integrity issues would not be described or directly assessed in the study;
- Due to the importance of localised factors as described above in assessing the suitability for CO_2 storage of any given gas field, the study would not seek to produce a screening tool for the ranking of gas field prospects (item 4 in the original scope). However a tool to enable regional source-sink matching with respect to time, based on the use of a geographic information system (GIS) would be developed.

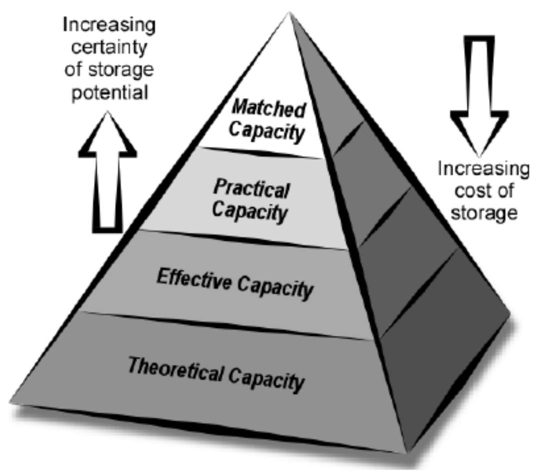

Figure 1: CSLF Resource Pyramid

Calculation of Storage Capacities

Data sources and limiting assumptions

The following data sources were utilised by the study:

1. The IEA GHG point source emission database;
2. The United States Geological Survey (USGS) National Oil and Gas Assessments (NOGA) and World Petroleum Assessment (WPA), dating from 1995;
3. The 2008 American Association of Petroleum Geologists (AAPG) Giant Fields Atlas.

As the study estimated global and regional storage capacity, it was necessary to use high level data and apply generic factors that may not be applicable in all situations. All efforts were made to use the most appropriate assumptions, but there were restrictions in available data and resources. Consequently, while this study advances our understanding of the global capacity for storing CO_2 in depleted gas fields, it could be enhanced with a more detailed analysis, for example at regional or national levels.

The nature of the various generic factors and simplifying assumptions employed are described in the sections below, for each level of the resource pyramid. It is important to note that the results of the study may not exactly match the definitions provided by the CSLF; nevertheless, reference to the pyramid definitions was still agreed as a worthwhile exercise to place the results in context.

Conversion of natural gas recoverable reserves to CO_2 storage capacities

All capacity calculations in the study were made by conversion of recoverable natural gas reserves (cumulative production plus remaining reserves) to an equivalent tonnage of CO_2, assuming a gas expansion factor (GEF) of 200 and an in-situ density for stored CO_2 of 0.7 tonnes/m^3. Calculations also assumed that CO_2 storage would return depleted gas fields to initial, pre-production pressures. These assumptions were major items for comment in many of the expert reviews (see below).

Methodology to determine theoretical, effective and practical storage capacities

The USGS datasets, used to determine theoretical, effective and practical capacities, do not include field-specific information such as depth or estimated closure dates. Instead, data is reported globally and for Assessment Units (AU) or Total Petroleum Systems (TPS) which contain a number of individual fields.

The USGS gas reserves include associated gas in oil fields, in addition to gas fields. To allow for this in the CO_2 storage capacity calculations, a mean value of gas to oil ratios in oilfields reported in the USGS WPA (2,200 cubic feet of gas per barrel of oil) was used to calculate the amount of associated gas and deduct from total gas reserves, to give gas reserves in gas fields.

Since the USGS dataset is based on studies in the mid 1990's, allowance was made in the calculations for both reserve growth and undiscovered reserves. The authors considered the inclusion of undiscovered reserves justified, and cited several examples of large gas fields already discovered since 1995 including Ormen Lange in the Norwegian North Sea and various fields of the northwest coast of Australia.

Theoretical capacity is defined as the physical limit that a geological system can accept. For the purposes of this study, theoretical capacity was obtained by simple conversion of recoverable gas reserves to an equivalent quantity of stored CO_2, using the assumed values of GEF (200) and CO_2 density ($0.7t/m^3$) stated above.

Effective capacity is defined as a subset of theoretical capacity obtained by applying a range of technical – geological/engineering – cut-off limits to the assessment. In this study, effective capacities were calculated assuming 75% of pore space originally occupied by natural gas could be filled with CO_2, to take account of technical factors such as water invasion and reservoir compaction. Whilst acknowledging this 75% factor as being 'crude', the report states that the assumption appears reasonable compared to factors derived from other studies.

Practical capacity is defined as a subset of the effective capacity that is obtained by considering technical, legal and regulatory, infrastructure and general economic barriers to CO_2 geological storage. In this study, two filters were applied to obtain practical capacity from effective capacities:

1. Reduction of capacity by removing fields with a capacities under 50Mt CO_2 for onshore scenarios and 100Mt CO_2 for offshore scenarios. These simplifying cut-offs were chosen based on, respectively: a 40 year injection life for a source of 1.25Mt, a reasonable minimum for a point source industrial emission with CCS potential; and a 40 year injection life for a 500MWe standard coal-fired plant, which was considered the minimum sized plant that might seek an offshore sink. Since the USGS dataset does not include field-specific information, this filter was applied by applying the statistical distribution of field sizes in Europe (the only available dataset, courtesy of the EU Geocapacity Project) to the entire world. It is acknowledged that the cut-off capacities and assumed field size distributions are potential sources of error in the calculations, particularly if applied at a regional level.
2. The study made an allowance for the potential for some sites to be unsuitable due to risks associated with potential leakage. A survey of natural gas storage analogues by the BGS has revealed approximately 1.3% of sites have experienced leakage. This industrial analogue provided the authors with the justification for reducing the practical capacity by 1% to allow for unsuitable sites. ***It should be stressed that the authors were not suggesting that capacity calculations should be reduced to allow for a leakage rate of 1% at all sites.***

In summary, ***practical capacity*** was calculated by reducing the effective storage capacity by 40% to allow for sub-sized (uneconomic) fields, and then by a further 1% to allow for a small number of sites being unsuitable due to the likelihood of leakage.

Theoretical, effective and practical storage capacities

Table 1 below presents the calculated global theoretical, effective and practical capacities:

Table 1. Estimates of Global CO_2 Storage Capacity from USGS Data

Capacity	Basis	Estimated CO_2 Storage Capacity (Gt)		
		F95*	Mean	F5**
Theoretical	Equivalent to total recoverable natural gas reserves	560	870	1,300
Effective	75% of theoretical, to allow for geological factors e.g. water invasion	420	650	940
Practical	60% of effective, with further 1% reduction for unsuitable sites due to potential leakage	250	390	560

Notes to Table 1:

All figures quoted to 2 significant figures

** 95% probability that capacity will be greater than this value, determined from USGS statistics of natural gas reserve growth and undiscovered reserves*

*** 95% probability that capacity will be lower than this value*

Regional estimates of theoretical, effective and practical capacity

The USGS AU/TPS data were utilised to estimate regional storage capacity, using the same methodology as outlined above; results from the study are summarised in Table 2 below.

Table 2. Regional CO_2 Storage Capacity Estimates from USGS Data

Region	Estimated Mean CO_2 Storage Capacity (Gt)		
	Theoretical	Effective	Practical
Asia-Pacific	100	75	45
Central/South America	60	45	27
Europe	83	62	37
Former Soviet Union	340	260	150
North America	75	56	33
Middle East & Africa	240	180	110
Total	**900**	**680**	**390**

Notes to Table 2:

All figures quoted to 2 significant figures

Note that the worldwide total estimates of theoretical and effective storage capacity in Table 2 are slightly higher than the estimates from USGS global data shown in Table 1. The authors acknowledge this discrepancy and cite the global data of Table 1 as a more reliable world estimate, due to that base data incorporating a more realistic gas to oil ratio for oil fields.

Methodology to determine matched storage capacities

Matched capacity is defined as a subset of the 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. For this study, source-sink matching was undertaken by developing a GIS-based semi-automatic network connection algorithm. Source data was taken from the IEA GHG point source emission database, whilst sinks were identified from the AAPG Giant Fields Atlas.

The atlas includes basic details on gas fields with reserves greater than 1.5 trillion cubic feet, which collectively comprise some 65% of the world's total natural gas reserves. Using the same basic assumptions as for the USGS data (GEF of 200, CO_2 density 0.7t/m^3), these fields equate to theoretical CO_2 storage capacities in excess of 100Mt. Fields at shallower depths than 800m were discounted during the study, and theoretical capacities were converted to effective capacities using the 75% factor as applied to the USGS data. However, no further technical constraints such as caprock integrity, injectivity or compartmentalisation, were applied.

The source sink matching was undertaken on a decade-by-decade basis until 2050. Estimated dates for storage availability (i.e. close of natural gas production, assuming CO_2-EGR will not be applied) were estimated by considering the total volume of recoverable reserves and the year of field discovery; the inherent uncertainty in this estimation was covered by grouping closure dates in decades. Fields with estimated closure dates beyond 2050 were excluded from the matched capacity calculations.

A number of working assumptions were needed for the source-sink matching algorithm, reference should be made to the report for a complete description. The basic algorithm process is illustrated in Figure 2 below.

Matched storage capacities

The report produced a series of regional summary maps illustrating the connection of sources and sinks derived from the algorithm. Table 3 below summarises matched regional capacity on a decade-by-decade basis.

Table 3. Regional Estimates of Matched CO_2 Storage Capacity

Region	Cumulative CO_2 Storage Capacity (Gt)			
	By 2020	By 2030	By 2040	By 2050
North America	11	15	17	17
South/Central America	2	5	6	8
Western Europe	4	9	11	11
Eastern Europe*	7	21	38	47
Middle East	6	25	32	33
Africa	1	11	13	13
Asia & Oceania	2	5	19	28
Total	**33**	**89**	**140**	**160**

Notes to Table 3:

All figures quoted to 2 significant figures

** Includes former Soviet Union*

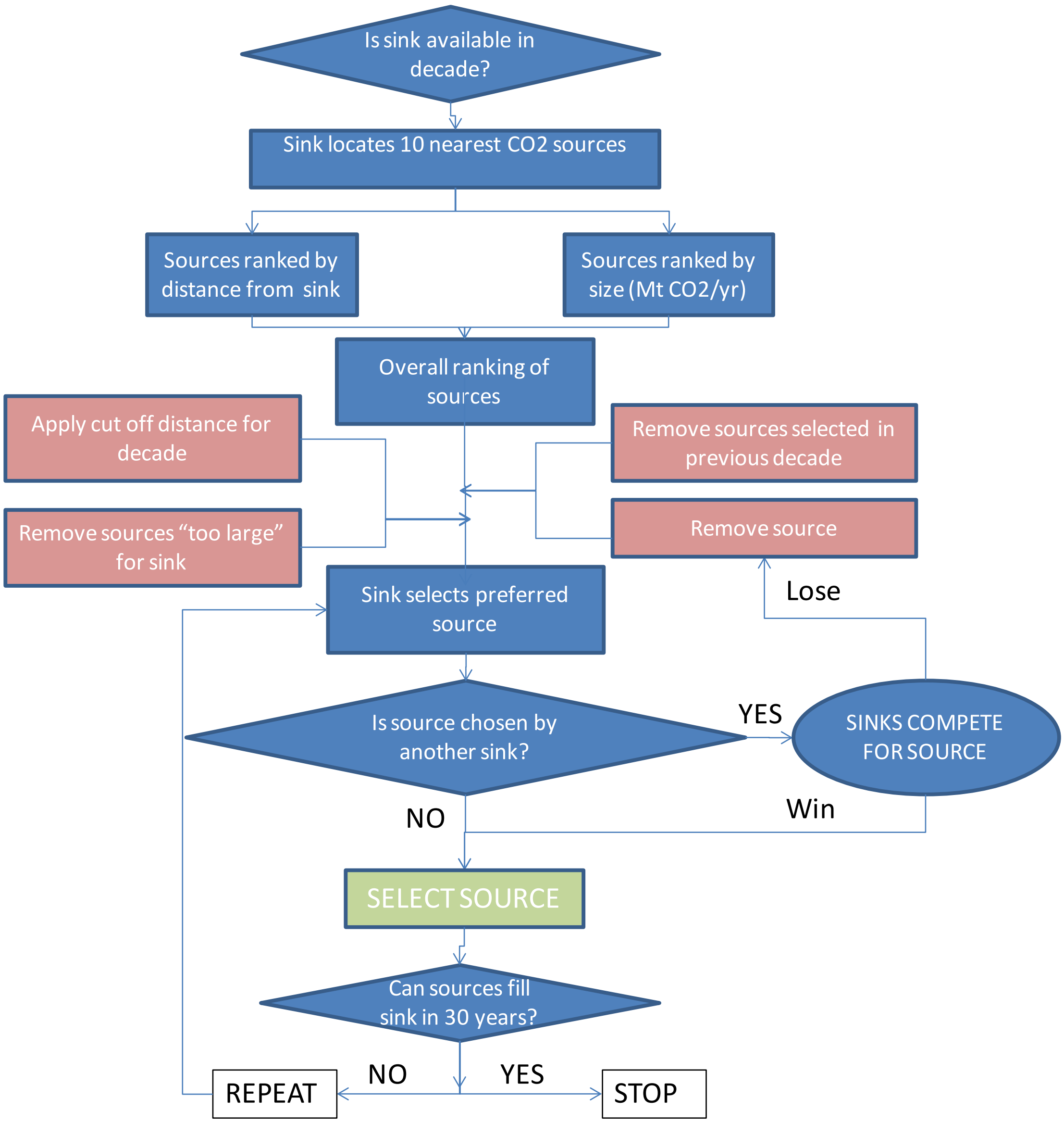

Figure 2: ***Source-Sink Matching Algorithm***

Cost Calculations for Storage

Methodology

The source-sink matching exercise used to estimate matched storage capacities also served as the basis to estimate costs of transport and storage. Cost elements addressed by the study were: pipelines; boosting (pumping and compression); surface injection facilities and wells; and storage integrity monitoring. There was sufficient information for over 200 of the source-sink connections identified by the study, to compile estimates of lifetime transportation and storage costs.

As with the storage capacity estimations, cost calculations derived from the study relied on a series of generic factors and simplifying assumptions, reflecting the global nature of the project and the time, resources and data available. Key assumptions were that existing natural gas production infrastructure, e.g. pipelines and wells, will not be suitable for CO_2 storage operations. This was recognised as being a conservative approach; however the timescale and scope of the study did not permit any obvious alternative. The algorithm also does not account for geopolitical factors. Full details of the methodology and simplifying assumptions are set out in the report.

Results of cost analysis

The study determined that, on a global basis up to 2050, 30Gt of storage capacity in depleted gas fields can be utilised for less than \$5 per tonne and 50Gt can be utilised for less than \$10 per tonne (Figure 3). The most cost-effective potential was found to be in Oceania, Asia, Eastern Europe including the former Soviet Union, and North America.

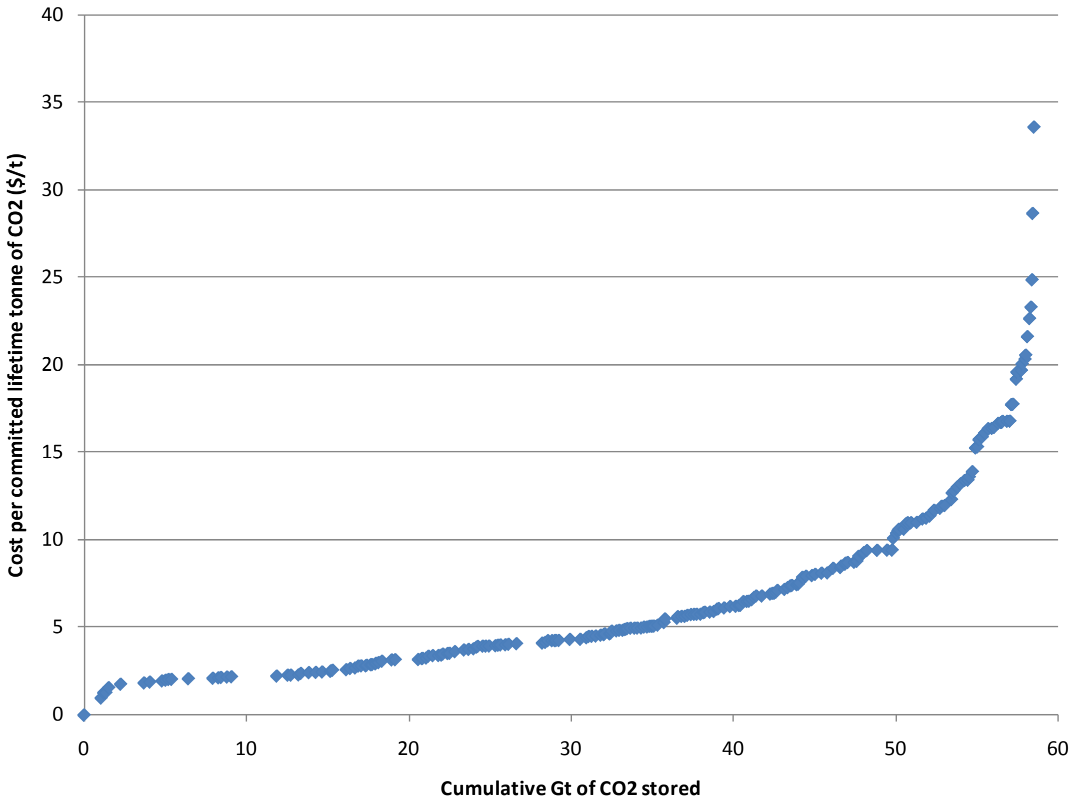

Figure 3: Global Marginal Abatement Curve

Expert Review Comments

Comments were received from 9 expert reviewers. Overall feedback was positive; most concerns addressed many of the generic factors and simplifying assumptions used, and these comments partly reflected regional perspectives on the source-sink matching exercise.

Some of the more significant comments are summarised below:

- Several reviewers felt that the field cut-off sizes of 50/100Mt capacity for onshore/offshore scenarios were too conservative, failing for example to recognise the potential of small fields occurring in clusters;
- Similarly, assumed values for CO_2 density ($0.7t/m^3$) and minimum field depth (800m) were also queried;
- The assumption that reservoirs would be filled to pre-production pressures also attracted comment; but whilst some reviewers pointed out that de-pressurisation during production may damage caprock integrity and thus limit re-pressurisation profiles, other reviewers pointed out that re-pressurisation above original levels may also be possible in some cases;
- The 75% and 60% capacity conversion factors used to convert theoretical to effective and then effective to practical, respectively, were recognised as reasonable for the scale of the study, but nevertheless somewhat arbitrary;

- Use of the European field size distribution to reduce global capacities from effective to practical was stated as probably not representative for other regions;
- Some of the economic factors used for the cost calculations were subject to sensitivity analyses – several reviewers felt that similar analyses for parameters used in the capacity calculations would also have been useful;
- Similarly, a probabilistic approach to capacity calculations would have been preferable;
- Capacities reported as ‘matched’ by the study do not allow for some geological and technical criteria (e.g. injectivity) and so could arguably be classed as ‘practical’;
- One reviewer from industry commented that some assumed cost items appeared to be underestimated and also that the regulatory, permitting and cost issues associated with pipeline construction may also be more onerous than acknowledged by the study.

Conclusions

The study has provided a fresh perspective on the global CO_2 storage potential of depleted natural gas fields. By placing capacity estimates generated in the context of the CSLF resource pyramid, the study has demonstrated how progressive application of various technical and economic factors serves to reduce estimated storage capacities to more realistic levels. The estimated 160Gt of matched storage capacity in depleted gas fields that could be available globally by 2050 may represent a more meaningful assessment than the previously reported 797Gt (IEA GHG, 2000) and similar estimates quoted elsewhere.

The timescale and scope of the project necessitated the use of basic global datasets, plus many simplifying assumptions and generic factors which are open to debate, particularly on a regional scale. The report can be considered as a starting point for further more detailed assessments, which could be performed on a regional basis with adjustments to the methodology and incorporation of refined input data, as appropriate.

Similarly, the derived cost estimates must be placed in the context of the assumptions necessitated by the global nature of the study. Nevertheless, the key assumption that existing gas production infrastructure could not be re-used is conservative; therefore the projected transport and storage costs of under $10 per tonne for up to 50Gt of CO_2 before 2050, illustrate that depleted gas fields represent an important economic CO_2 storage opportunity.

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NATURAL ENVIRONMENT RESEARCH COUNCIL

CO2 STORAGE IN DEPLETED GAS FIELDS

A report to IEA GHG R&D Programme

March 2009

CO_2 STORAGE IN DEPLETED GAS FIELDS

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EXECUTIVE SUMMARY

In March 2008 the IEA GHG R&D Programme, hereafter IEA GHG, commissioned a consortium comprising Pöyry, Element Energy and the British Geological Survey (BGS) to review the global potential for storing CO_2 in depleted gas fields.

This work advances the analysis undertaken in the IEA GHG 2000 report *Barriers to Overcome in Implementation of CO_2 Capture and Storage: Storage in Disused Oil and Gas Fields* through including more recent data and taking into account economic and logistic factors. The results enable us to provide storage capacity estimates that align with the resource pyramid definitions of storage capacity that the Carbon Sequestration Leadership Forum (CSLF) has proposed. These definitions include:

- ***theoretical capacity*** being the physical limit a geological system can accept;
- ***effective capacity*** being the capacity assessment once geological and engineering limits have been applied;
- ***practical capacity*** being the capacity assessment once technical, legal, regulatory, infrastructure and economic barriers have been applied; and
- ***matched capacity*** which is obtained through detailed matching of large stationary CO_2 sources with appropriate geological storage sites.

This study used USGS data to provide global and regional estimates of theoretical, effective and practical capacity and developed a model which linked large CO_2 sources with giant gas fields to provide an estimate of matched capacity. The analysis of the latter considered which decade the giant gas fields would become available to store CO_2, and produced a series of maps showing the links between the sources and the sinks. In addition, we estimated global and regional marginal abatement curves for transporting and storing CO_2 in giant gas fields.

As this study estimates the global and regional storage capacity, it was necessary to use high level data and apply generic factors that may not be applicable in all situations. All efforts were made to use the most appropriate assumptions, but there were restrictions in available data and resources. Consequently, while this study advances our understanding of the global capacity for storing CO_2 in depleted gas fields, it could be enhanced with a more detailed analysis.

Table 1 below summarises this study's estimates of cumulative theoretical, effective and practical CO_2 storage capacity, based on the USGS global assessments, and the matched CO_2 storage capacity based on giant gas fields.

The analysis of the USGS Global Assessment data does not consider when gas fields will become available for storing CO_2, and so estimated capacities do not change with time, whereas the analysis based on giant gas fields does consider when they will become available and so increases over time.

Table 1 – Estimated cumulative storage capacity in depleted gas fields (Gt)

Decade	Theoretical	Effective	Practical	Matched
By 2020	868	651	387	33
By 2030				89
By 2040				137
By 2050				158

Note: The theoretical, effective and practical estimates are based on USGS Global Assessments data and are constant over time while the matched estimates are based on the Giant Fields Atlas and change as sinks become available.

The key points that emerge from this part of the analysis are listed below.

- The estimate of storage capacity from the Initial Study was of 797 Gt, which took into account edge effects, which is predominately water entering and taking up space in the reservoir. This means that the most suitable comparison from this study is with our estimate of effective capacity, which is 651 Gt. This is lower than the estimate from the Initial Study and is largely due to our exclusion of associated gas.
- The estimate practical capacity is significantly lower than the estimate of effective capacity, which shows the impact of removing gas fields that are too small to be cost effective for storing CO_2 or are not considered suitable due to the risk of potential storage security.
- The impact of when giant gas fields become available for injecting CO_2 further reduces capacity estimates. The matching of 566 large CO_2 sources with 266 giant gas fields that are sufficiently close yields a matched storage capacity estimate of 33 Gt by 2020 rising to 158 Gt by 2050.

To put these capacity estimates in perspective, global average annual CO_2 emissions in 2015 from stationary sources emitting more than 1 $MtCO_2$ pa are predicted to be approximately 12 Gt. The analysis indicates that depleted gas fields available before 2050 could store 13 years of this volume of CO_2.

The predicted available capacity from giant gas fields appears sufficient, in principle, to accommodate the CCS uptake scenarios recently proposed by the International Energy Agency (IEA 2008) by 2050. Over the longer term, and in the light of likely technical, economic, political, social and regulatory constraints on specific projects, oilfields and saline aquifers would also need to be developed if CCS is to make its full contribution to mitigating climate change at lowest overall cost.

The USGS Global Assessment data does not enable a regional analysis of storage capacity; however, it is possible to do so using the USGS Total Petroleum System (TPS) data and the Giant Fields Atlas. The Global Assessment data uses slightly different gas-to-oil ratio than the TPS data, so the sum of our regional estimates of storage capacity based on TPS data shown in Table 2 overleaf are slightly higher than the estimates shown in Table 1 above. Further, the definitions of regions are slightly different in the analyses of the TPS data and the Giant Fields Atlas, so we have shown both regional breakdowns of storage capacity in separate tables. Table 3 overleaf shows the estimates of matched storage capacity.

Table 2 – Estimates of regional CO_2 storage capacity in gas fields (Gt)

Region	Theoretical	Effective	Practical
Asia-Pacific	101	75	45
Central and South America	60	45	27
Europe	83	62	37
Former Soviet Union	341	256	152
North America	75	56	33
Middle East & Africa	238	178	106
Total	**897**	**673**	**400**

Source: USGS Total Petroleum System data

Table 3 – Estimates of matched CO_2 storage capacity in gas fields by region (Gt)

Region	By 2020	By 2030	By 2040	By 2050
North America	11	15	17	17
South/Central America	2	5	6	8
Western Europe	4	9	11	11
Eastern Europe/FSU	7	21	38	47
Middle East	6	25	32	33
Africa	1	11	13	13
Asia & Oceania	2	5	19	28
Total	**33**	**89**	**137**	**158**

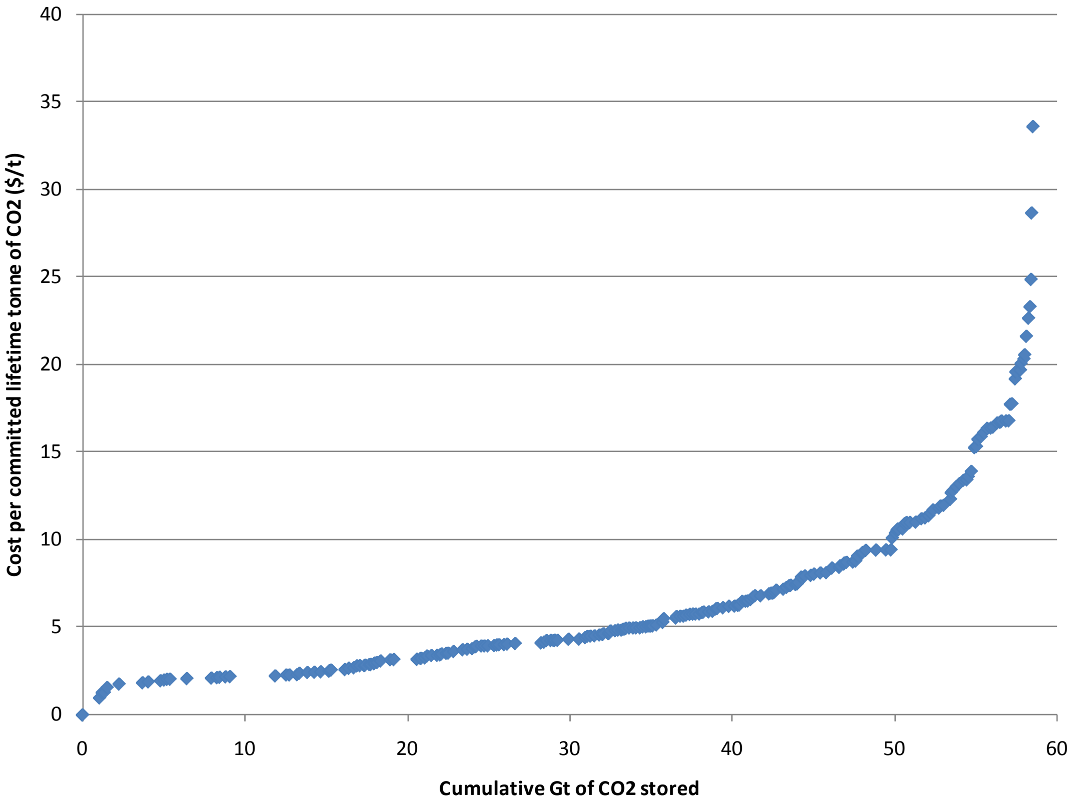
Source: Giant Fields Atlas

The key finding from the regional analysis is that the Former Soviet Union and the Middle East have the greatest potential for storing CO_2 in depleted gas fields, but that the significant distance between sources and sinks in the Middle East mean that it will take a significant period of time to use the potential in the Middle East.

Marginal abatement curves

Of the 233 gas fields that were connected to large CO_2 sources, there was sufficient information on 222 of them to estimate the lifetime cost of transporting and storing each tonne of CO_2. Figure 1 below shows the ranking of these costs in 2008 US currency.

Figure 1 – Marginal abatement curve for transport and storage



The costs this study estimates for transport and storage in giant depleted gas fields connected to large sources are significantly lower than the majority of published capture costs, which are typically estimated to be at least \$30/t CO_2.

Abatement curves were derived from an analysis of commitments to store 60 Gt CO_2 in 222 giant gas fields. This analysis indicates that 30 Gt of CO_2 can be transported and stored for less than \$5 per tonne, rising to 50 Gt of CO_2 being transported and stored for less than \$10 per tonne.

The regional analysis found that the most cost effective storage potential is found in Asia, Oceania, Eastern Europe, the Former Soviet Union and North America.

1. INTRODUCTION

1.1 Background to project

In March 2008 the IEA GHG R&D Programme, hereafter IEA GHG, commissioned a consortium comprising Pöyry, Element Energy and the British Geological Survey (BGS) to review the global potential for storing CO_2 in depleted gas fields.

A key objective of this work is to advance the analysis undertaken in the IEA GHG report *Barriers to Overcome in Implementation of CO_2 Capture and Storage: Storage in Disused Oil and Gas Fields*, hereafter the *Initial Study*, which identified a total potential worldwide capacity of 923 Gt CO_2, in depleted oil and gas fields, of which 797 Gt is in depleted gas fields.

The Initial Study assessed the physical capacity in gas reservoirs and did not take account of economic and logistic factors such as:

- the suitability of the reservoirs for storing CO_2, such as whether they are the appropriate size;
- whether the distance between the reservoirs and CO_2 sources exclude some reservoirs as being impractical to use; and
- when the reservoirs would become available for storing CO_2.

When these factors are taken into account, the estimate of global storage capacity is significantly lower than the 797 Gt that the Initial Study found.

Taking different factors into account has resulted in a range of estimates of CO_2 storage capacity. The Carbon Sequestration Leadership Forum (CSLF) has examined the impact that different methodologies and assumptions have had on the estimates of CO_2 storage capacity and suggested the option of classifying them in one of four types, which can be represented as a resource pyramid[1]. Figure 1 overleaf shows such a pyramid, in which:

- ***theoretical capacity*** is the physical limit of what the geological system can accept;
- ***effective capacity*** is the capacity assessment once geological and engineering limits have been applied;
- ***practical capacity*** is the capacity assessment once technical, legal, regulatory, infrastructure and economic barriers have been applied; and
- ***matched capacity*** is obtained through detailed matching of large stationary CO_2 sources with appropriate geological storage sites.

Storage sites in the matched capacity category have good geological characteristics, large storage capacity and are located close to CO_2 sources, while those within the theoretical capacity include these and sites with poor geological characteristics, small storage capacity and located considerable distances from CO_2 sources. Consequently, estimates of the theoretical capacity will be much greater than estimates of matched capacity, and

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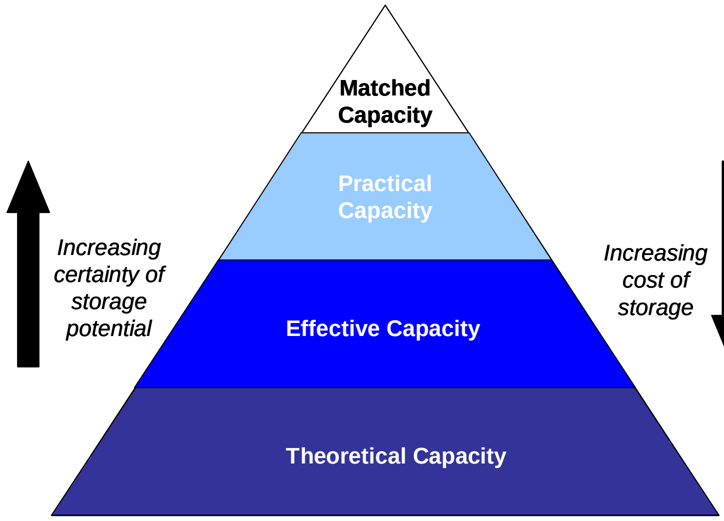
[1] See *Phase II Final Report from the Task Force for Review and Identification of Standards for CO2 Storage Capacity Estimation* and *Comparison between Methodologies for Estimation of CO2 Storage Capacity in Geological Media*.

the average unit cost of storing CO_2 in the matched capacity sites will be lower than the average unit cost of storing CO_2 in the theoretical capacity sites.

Figure 2 – High level resource pyramid



Source: Based on CSLF

The Initial Study provided estimates of both the:

- theoretical capacity, termed CO_2 Volume, that estimates the volume of CO_2 that can be stored in depleted gas fields taking into account the pressure and temperature in the reservoirs; and
- effective capacity, termed CO_2 Sequestration Potential, which is taken as 75% of the CO_2 volume as 25% of the potential storage space may not be available due to field edge effects, water influx or other reasons.

This study extends this analysis through:

- deriving new estimates of global gas reserves from the USGS National Oil and Gas Assessments and World Petroleum Assessment;
- making use of the Giant Fields Atlas[2], which contains high level information on very large oil and gas fields;
- developing and applying additional filters which can provide estimates of theoretical, effective, practical and matched CO_2 storage capacity in depleted gas fields, as defined by the Carbon Sequestration Leadership Forum; and
- estimating marginal abatement curves of transporting and storing CO_2 in giant gas fields

The analysis in this study is restricted to depleted gas fields, meaning that other options for geological storage of CO_2, such as in depleted oil fields and saline aquifers, were not considered.

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2 See M Horn, 2008, http://sourcetoreservoir.com.

As this study estimates the global and regional storage capacity, it was necessary to use high level data and apply generic factors that may not be applicable in all situations. All efforts were made to use the most appropriate assumptions, but there were restrictions in available data and resources. Consequently, while this study advances our understanding of the global capacity for storing CO_2 in depleted gas fields, it could be enhanced with a more detailed analysis.

The USGS data provides information on gas reserves in Assessment Units[3] (AU) within a region rather than on individual gas fields. Thus it does not include field specific information, such as:

- the depth of the fields, which is needed to ascertain if the field is suitable for storing CO_2 and if so what the cost of drilling injection wells will be;
- when the fields in the region will be available to store CO_2; and
- the distance between the fields and CO_2 sources, as the regions can be very large.

The Giant Field Atlas provides much of this information, and enables the analysis to be developed further. While this information only covers a subset of the gas fields that could be used to store CO_2, it is likely that they will be preferred sites for storing CO_2 as they:

- can store significant volumes of CO_2, meaning that the costs of establishing them as sinks can be spread over many years of operation and potentially a large number of capture projects; and
- are too large to be used to store natural gas.

Further, given that the information available for the giant gas fields enables them to be linked with CO_2 sources, it is possible to ascertain the impact of filters such as when the gas fields will be available and the costs of transporting and storing CO_2 has on storage capacity estimates.

With regard to the USGS data, the filters developed and applied include:

- using the gas-to-oil ratio to account for the associated gas found in oil fields within a basin, and thus to estimate the volume of gas in gas fields;
- removing gas fields that are too small to be cost effective for storing CO_2, which we take to be those that have a capacity of less than 50 $MtCO_2$ for onshore fields and 100 $MtCO_2$ for offshore fields; and
- reducing the capacity estimate to account for any loss of fields that may not be suitable for storing CO_2 due to a higher risk of security storage;

Regarding the giant gas fields, these filters include:

- removing giant gas fields that are less than 800m below the surface, as the pressure and temperature in such fields are unlikely to be sufficient for the CO_2 to remain in a dense phase, which would mean that the mass of CO_2 that could be stored in them would be significantly less than those whose depth is greater than 800m;
- the decade in which gas fields are expected to become available to inject CO_2; and
- cost of transporting and storing CO_2.

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3 An AU is the volume of rock within a petroleum system containing both discovered and undiscovered hydrocarbon fields and share similar geologic traits and socioeconomic factors.

This study has not been able to take a range of factors into account, including:

- how political, legal and regulatory factors may influence the take up and deployment of CCS technology and infrastructure;
- how commodity prices may influence the close of production (CoP) dates for gas fields; or
- engineering issues that could influence estimates of CO_2 storage capacity.

The application of additional data and filters significantly reduces estimates of CO_2 storage capacity in depleted gas fields. However, the analysis does not exactly match the categories in the CSLF resource pyramid (Bachu et al. 2007). In this report four sets of CO_2 storage capacity estimates are given:

- A global estimate of the mass of CO_2 that could be stored in the pore space occupied by the ultimately recoverable reserves of natural gas in gas fields if injecting CO_2 restores the reservoir to its original pressure. This equates well to the ***theoretical*** storage capacity defined in Bachu et al. (2007), which assumes that:

  … the entire volume is accessible and utilized to its full capacity to store CO_2 in the pore space, or dissolved at maximum saturation in formation fluids, or adsorbed at 100% saturation in the entire coal mass. This represents a maximum upper limit to a capacity estimate, however it is an unrealistic number as in practice there always will be physical, technical, regulatory and economic limitations that prevent full utilization of this storage capacity.

- A global estimate of the mass of CO_2 that could be stored in 75% of the pore space occupied by the ultimately recoverable reserves of natural gas in gas fields globally if injecting CO_2 restores the reservoir to its original pressure. This estimate crudely takes account of geological factors such as the potential for water invasion, reservoir compaction, etc. that would likely reduce the pore space available for CO_2 storage in natural gas fields. This estimate roughly corresponds to the ***effective*** capacity category of Bachu et al. (2007), which:

  … represents a subset of the theoretical capacity and is obtained by applying a range of technical (geological and engineering) cut-off limits to a [theoretical] storage capacity assessment.

- A global estimate based on the estimate of effective capacity that further constrains the storage capacity by discounting a proportion of the global total storage capacity in gas fields that is considered likely to be in fields not economic CO_2 storage. It also makes a 1% discount to allow for storage projects could not be initiated due to the potential risk of leakage. This corresponds roughly to the practical capacity of Bachu et al. (2007) which:

  … is that subset of the effective capacity that is obtained by considering technical, legal and regulatory, infrastructure and general economic barriers to CO_2 geological storage in that it broadly takes an economic factor into account. However, it does not take into account technical, legal, regulatory, infrastructure and other economic factors.

- Field-by-field estimates based the Giant Field Atlas, that excludes fields less than 800 m deep and determine CO_2 storage capacity based on source-sink matching techniques. These correspond roughly to the ***matched*** capacity of Bachu et al. (2007) which:

…is that subset of the 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, availability and supply rate.

Considering that legal and regulatory frameworks for CCS have not yet emerged in most countries, the match between the CSLF categories and the estimates given in this report is considered sufficiently close to warrant the use of the CSLF terms in this report. Table 4 below indicates the areas of overlap and gaps between the Initial Study, this study and the resource pyramid categories.

Table 4 – Comparison of capacity estimate definitions

CSLF capacity category	CSLF definition	Equivalent in this study	Approximate equivalent in Initial Study
Theoretical	The physical limit of what the geological system can accept. Occupies the whole of the resource pyramid. It assumes that the entire volume is accessible and utilized to its full capacity to store CO_2 in the pore space	Global estimate of the mass of CO_2 that could be stored in the pore space occupied by the URR of natural gas in gas fields if injecting CO_2 restores the reservoir to its original pressure. Assumes constant CO_2 density of 0.7 tonnes/cubic metre, constant gas expansion factor of 200.	Global estimate of the mass of CO_2 that could be stored in the pore space occupied by the URR of natural gas in gas fields if injecting CO_2 restores the reservoir to its original pressure. Uses variable methane and CO_2 density based on constant geothermal and pressure gradients.
Effective	A subset of the theoretical capacity obtained by applying a range of technical (geological and engineering) cut-off limits to a storage capacity assessment.	A global estimate of the mass of CO_2 that could be stored in 75% of the pore space occupied by the URR of natural gas in gas fields globally if injecting CO_2 restores the reservoir to its original pressure. This estimate crudely takes account of geological factors such as the potential for water invasion and reservoir compaction that would reduce the pore space available for CO_2 storage.	As this study.
Practical	A subset of the effective capacity that is obtained by considering technical, legal and regulatory, infrastructure and general economic barriers to CO_2 geological storage.	A subset of Effective Capacity that further constrains the storage capacity by removing a proportion of the global storage capacity in gas fields that is likely to be in fields too small for economic CO_2 storage.	n/a
Matched	A subset of the 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.	Field-by-field estimates based on the Giant Field Atlas, that discount fields at depths of less than 800m and determine CO_2 storage capacity based on availability and source-sink matching techniques.	n/a

In addition, the project also seeks to extend the understanding of:

- competition for depleted gas fields between storing natural gas and storing CO_2;
- expected development of gas fields with high concentrations of CO_2; and
- impact of using CO_2 for enhanced gas recovery.

1.2 Structure of report

The report is organised in the following sections and a series of annexes:

- Section 2 outlines the analysis of CO_2 storage capacity based in the USGS Assessment;
- Section 3 analyses the cost of CO_2 transport and storage;
- Section 4 details the analysis of CO_2 storage in depleted giant gas fields;
- Section 5 discusses additional factors influencing CO_2 storage in depleted gas fields;
- Section 6 summarises the findings and results;
- Annex A details supplementary information;
- Annex B summarises the gas fields data;
- Annex C provides a worked example of linking large CO_2 sources with a giant gas field;
- Annex D outlines some sensitivities to the analysis; and
- Annex E contains a bibliography.

2. CO_2 STORAGE CAPACITY IN DEPLETED GAS FIELDS BASED ON USGS DATA

2.1 Introduction

This section updates the estimates of theoretical storage capacity in depleted gas fields from the Initial Study and applies a series of filters that produce estimates of effective and practical CO_2 storage capacity. Before these estimates are given there is a description of the data and methodology used.

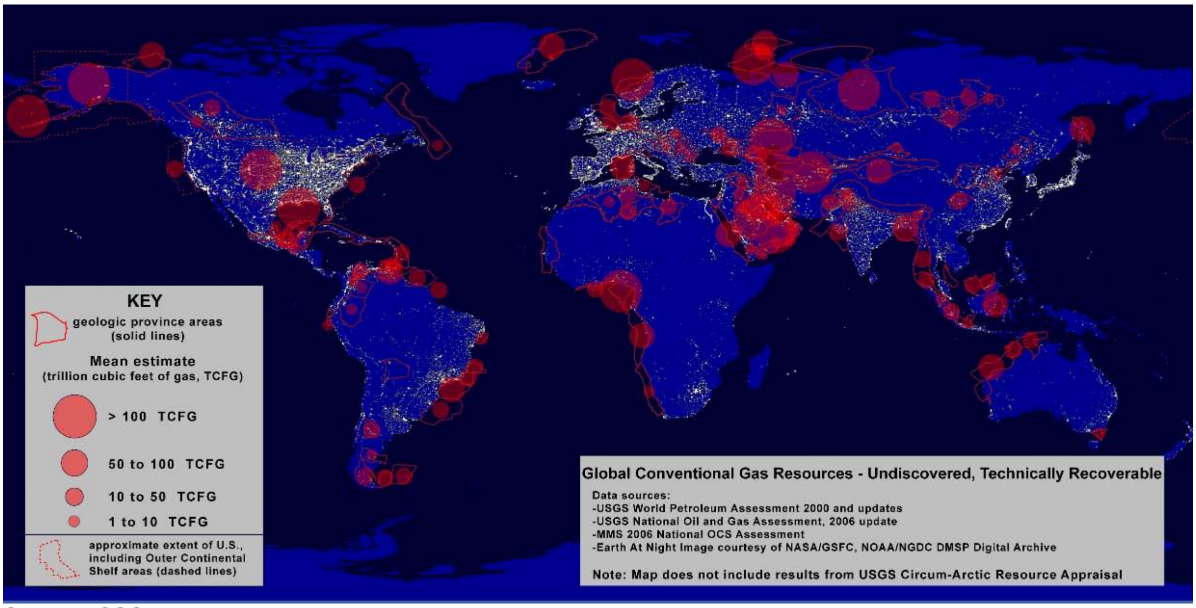
2.2 Global data on depleted gas fields

The data used to estimate the total global and regional CO_2 storage potential in gas fields was from the:

- USGS World Petroleum Assessment from the U.S. Geological Survey World Energy Assessment Team, 2000[4], hereafter referred to as USGS WPA. This data is incrementally updated.
- USGS National Oil and Gas Assessment[5], hereafter referred to as USGS NOGA. This data is an incrementally updated version of US Geological Survey National Oil and Gas Resource Assessment Team (1995).

Figure 3 below is a world map showing the future gas reserves based on most recent studies.

Figure 3 – Global Conventional Gas Resources



Source: USGS

4 Available at http://certmapper.cr.usgs.gov/rooms/we/index.jsp.

5 Available at http://energy.cr.usgs.gov/oilgas/noga/.

2.2.1 Additional data on gas fields

We also drew on more recent information sources, which include:

- AAPG Giant Fields database (Halbouty 2003); and
- the Giant Fields Atlas purchased specifically for the project, which updates the AAPG Giant Fields database (Horn 2008).

These databases have been used mainly in the economic analysis of storage potential, but also provide a cross-check on the regional estimates of CO_2 storage capacity.

2.3 Basis for analysing CO_2 storage capacity in depleted gas fields

2.3.1 Refilling of depleted gas fields to initial pressure

The principal assumption used in the analysis is that a depleted gas field could be refilled with CO_2 up to its initial pre-production pressure – on the basis that the field is known to have retained natural gas at this pressure for geological timescales and that it should be able to retain CO_2 at the same pressure. It is possible that some, possibly many, gas fields could be pressurised to levels above their initial pore fluid pressure. However, it seems likely that regulators might consider the initial pressure as a suitable limit, at least in the absence of evidence that a specific field could retain gas at greater pressures than that at which it was discovered, or evidence that the cap rock above the gas reservoir has been damaged during the production period. The cap rock could be damaged by compaction of the reservoir rock when the pore fluid pressure in the reservoir is lowered during production, which could relieve stress on the cap rock and cause existing fractures to dilate or new fractures to be created.

The production wells would have pierced the cap rock, and it is assumed that these have been constructed and will be abandoned in a way that seals the reservoir satisfactorily. Should this not be the case, poorly constructed or poorly plugged wells can be remediated, although in offshore fields this could be a very expensive proposition.

The chance that some gas fields might be considered unsuitable for CO_2 storage because the reservoir was insecure were investigated by considering the track record of natural gas storage sites in oil and gas fields. Natural gas storage operations are in many ways analogous to CO_2 storage, the main difference being that natural gas storage occurs for the short to medium term rather than the long term.

Research by Evans (in press) into natural gas storage projects located in depleted oil and gas fields indicates that problems of leakage have been recorded at 22 sites. Of these:

- 14 were well, casing or above-ground infrastructure problems, that could be remediated in a CO_2 storage project in a depleted natural gas field; and
- eight were caused either by leakage via natural unidentified migration pathways through or around the cap rock above the storage reservoir and/or overfilling of the storage structure.

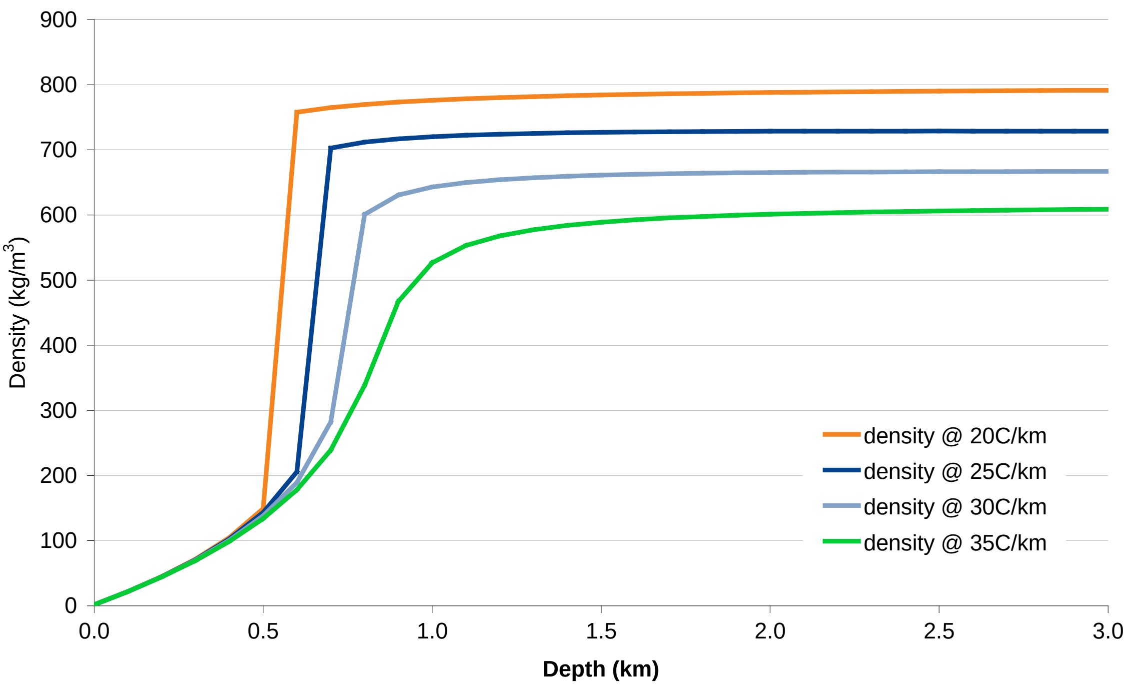
A conservative assumption would be that none of the latter eight leakage cases were caused by overfilling of the storage structure that could be successfully identified and remediated prior to a CO_2 storage project. There are thought to have been approximately 607 natural gas storage projects operational worldwide in total. Eight cases of leakages that could not be remediated out of 607 is 1.3%.

2.3.2 Density of CO_2 at initial reservoir conditions

To estimate accurately the density of CO_2 at initial pre-production reservoir conditions, it is necessary to know the initial reservoir temperature and pressure. However, under typical geological conditions, assuming a constant geothermal gradient and hydrostatic pressure, the density of CO_2 tends to plateau at depths below about 700 to 800 m and typically will vary between about 600 and 800 kg/m^3. In the absence of site-specific data the assumption has been made that the density of CO_2 under reservoir conditions in all gas fields will be 700 kg/m^3.

Figure 4 below illustrates the range of densities CO_2 has at a range of realistic geothermal gradients assuming a hydrostatic pressure gradient and a surface temperature of 10°C.

Figure 4 – Density of CO_2 by depth and temperature



Source: Sintef Petroleum Research

2.3.3 Storage space available within a depleted gas field

The storage space available for CO_2 in a depleted gas field depends principally on the space vacated by produced gas, the space occupied by any fluids that have been injected into, or naturally invaded, the gas field and on compaction of the pore space in the gas field. In gas fields that are in contact with an aquifer, formation water invades the reservoir as the pressure declines because of production, leading to a decrease in the pore space available for CO_2 storage. Carbon dioxide injection can partially reverse the aquifer influx, making more pore space available for CO_2. However, not all the previously hydrocarbon-saturated pore space will become available for CO_2 because some residual water may be trapped in the pore space due to capillarity, viscous fingering and gravity effects (Bachu et al. 2007). Ideally the proportion of the pore space that would be available would be estimated by reservoir simulation but this is clearly impractical on a global scale. To enable comparison with the Initial Study (IEA GHG 2000), we have maintained the assumption that 75% of the space occupied by the ultimately recoverable reserves of gas in the field is available for CO_2 storage. This assumption appears reasonable when compared to factors derived by simulation (Bachu & Shaw 2003).

2.3.4 Gas expansion factor

The gas expansion factor (GEF) is the ratio between the volume of natural gas under reservoir conditions and its volume at a standard temperature and pressure (STP) representing surface conditions. The current usage of STP, particularly in North America, is predominantly 60°F and 14.7 psi. In Europe and South America, current usage is typically 15°C and 14.7 psi (101.325 kPa). While GEF is field-specific, this study applied the average GEF of 200 to all gas fields, which was taken from van der Straaten (1996).

2.4 Filters for estimating CO_2 storage capacity in gas fields

This analysis begins with cumulative production and remaining reserves, which are expressed in terms of volume of gas, such as trillion cubic feet (tcf) or billion cubic metres (bcm). These values were converted into the mass of CO_2 that could be stored using the following equation:

$$M_{CO2t} = URRgas_{stp} \times B_g \times \rho CO_{2r}$$

Where:

M_{CO2t} is the mass of CO_2 stored in tonnes;

$URRgas_{stp}$ is the Ultimately Recoverable Reserves of gas at standard temperature and pressure in m^3;

B_g is the formation volume factor, or the reciprocal of the GEF from reservoir conditions to STP, and is assumed to be 0.05, following van der Straaten in Holloway et al. 1996;

ρCO_{2r} is the density of CO_2 at reservoir conditions in tonnes per m^3, which is assumed to be 0.7, following van der Straaten in Holloway et al. 1996;

B_g and ρCO_{2r} are mainly a function of reservoir temperature and pressure, but also can be affected by gas composition. Whilst oil and gas reservoirs are commonly hydrostatically pressured this is by no means always the case. Thus estimating these factors on the basis of reservoir depth and an assumed geothermal gradient would not necessarily be more accurate than the assumptions made above.

Gas fields also may contain oil and natural gas liquids (NGLs). NGLs are hydrocarbons that are gaseous at reservoir conditions and therefore covered by the gas expansion factor used to calculate the pore volume occupied by the gas at reservoir conditions. Oil in gas fields has not been included in the analysis.

We applied the following four filters to global estimates of gas reserves to produce an estimate of practical CO_2 storage capacity in depleted gas fields:

- the gas in gas fields, that is removing the ‘associated’ gas in oilfields;
- the storage limit within the gas fields;
- the gas fields are sufficiently large; and
- any potential storage security.

These filters are briefly discussed before being applied below.

2.4.1 Gas in gas fields

Part of the estimate of global gas reserves is associated gas, which is gas found in oil fields either dissolved in the oil or as free gas. As the subject of this study is capacity in depleted gas fields, we have excluded the associated gas by applying an average gas-to-oil ratio to determine the volume of gas in oil fields and deducting this from the estimate of global gas reserves to leave an estimate of total gas in gas fields.

2.4.2 Storage limit

The formula used to apply the storage limit to the estimate of CO_2 storage capacity is:

$$M_{CO2t} = URRgas_{stp} \times B_g \times \rho CO_{2r} \times E$$

E is the storage efficiency factor, representing the proportion of the reservoir space occupied by the ultimately recoverable reserves of gas in the field that is considered to be available for CO_2 storage. We were asked use the same assumption for storage efficiency as that used in the Initial Study, which was 75%, as this would increase the comparability of the studies.

2.4.3 Size of gas fields

A significant proportion of the estimated gross CO_2 storage capacity in gas fields occurs in fields that are considered likely to be to be too small for CO_2 storage to be a viable proposition in the next 50 years. Perceptions of the minimum size cut-off that should be applied may differ, and this is potentially a significant source of error in the analysis. Moreover, the minimum size cut-offs applied for onshore fields and offshore fields are likely to differ for economic reasons. The cut-offs considered appropriate in this study are 50 and 100 $MtCO_2$ storage capacity onshore and offshore respectively.

The size cut-offs for onshore and offshore fields were selected because we considered that operators would seek to use sinks that were capable to containing at least the lifetime emissions from a single CO_2 source, as this would enable them to minimise fixed costs, such as for the infrastructure and permitting.

We assumed that the smallest plant that might seek an offshore sink would be a 500 MWe standard coal-fired power plant which, operating at baseload, would produce between 2.5 and 3 $MtCO_2$ pa. This would require a reservoir with a capacity of 100 $MtCO_2$ or more if it had a 40 year lifetime. Similarly, it was felt that the smallest source that was likely to be considered for CO_2 capture and storage would initially have emissions of about 1 $MtCO_2$ pa, producing of the order of 1.25 Mt pa when fitted for CO_2 capture. It was assumed that such a plant would have to seek an onshore storage site for CCS to be economic.

Several of the giant fields considered in the analysis actually comprise two or more pools of gas either separated laterally by water bearing reservoir rock or arranged vertically above one another in multiple reservoirs. Such fields are similar to a group of closely associated smaller fields, except that the latter may be operated independently. It is recognised that groups of smaller, individually named and separately operated fields could, when combined, form a valid sink with a total capacity greater than the minimum field size cut-offs used in the study. However, even if such groups of smaller fields could be identified, it is quite possible the whole group might not be available for storage when required. Such groups of smaller fields could not be included in the analysis because of the limitations of the data available for the study.

The need to use very large sinks when storing CO_2 makes it unlikely that there will be competition for depleted gas fields between storing natural gas and storing CO_2. Typically reservoirs used to store natural gas will be much smaller in size than those used to store CO_2, as smaller reservoirs do not require substantial volumes of cushion gas and the pressure increases quickly during injection which facilitates a rapid withdrawal. This is illustrated in the following points.

- The largest gas storage site in the world is Severostavropolskoe in Russia, which has approximately 24 bcm capacity for working gas and 37 bcm of cushion gas, which together could store 150 $MtCO_2$.
- Severostavropolskoe is very much an exception, as there is only one other gas storage site that can hold more than 30 bcm of natural gas, a capacity that can store approximately 75 $MtCO_2$.
- Only 47 out of 607 gas storage sites, or 8%, can hold more than 3 bcm of natural gas, a capacity that can store 7.5 $MtCO_2$.

2.4.4 Unsuitable fields

As discussed in section 2.3.1, research on gas leaking from gas fields used to store natural gas has shown that gas has escaped from eight out of an estimated 607 projects, which represents 1.3% of cases. Consequently, to account for the possibility of some gas fields proving technically unsuitable for storage, we have adjusted down our estimate of storage capacity by 1%.

2.5 Application of the method

In the USGS WPA, the assessment of the produced petroleum and remaining reserves of individual oil and gas fields throughout the world is based on the following databases:

- Petroconsultants Inc[6]. 1996 Petroleum Exploration and Production database (Petroconsultants, 1996a);
- Petroconsultants Inc. 1996 PetroWorld 21, Version 2.4, Q2 1996 (Petroconsultants, 1996b);
- other area reports from Petroconsultants, Inc.; and
- NRG Associates, Inc. Significant Oil and Gas Pools of Canada database (1995).

The Petroconsultants databases were used for all areas of the world outside Canada. They include fields discovered up to the end of 1995.

The corresponding information in the USGS NOGA was compiled from the following data sources:

- PI/Dwights Plus US Production Data (IHS Energy Group, 2003a);
- PI/Dwights Plus US Well Data (IHS Energy Group, 2003b); and
- NRG Associates, Inc. Significant Oil and Gas Fields of the United States (NRG Associates, 2002).

The individual field data in the above databases is proprietary but data grouped by AU and Total Petroleum System (TPS[7]) are available from the USGS. In some of the USGS

6 Now IHS Energy Ltd.

WPA data tables the fields are divided into oil and gas fields, where an oil field is defined as a field where the gas-oil ratio is less than 20,000 scf gas per barrel of oil. This study uses the same definition.

2.5.1 Known reserves

The known hydrocarbon reserves in the USGS WPA and the USGS NOGA are the sum of all the hydrocarbons produced from all discovered fields and their remaining reserves. The remaining reserves are classified as 'proven plus probable' (P2) for the world outside North America, and 'proven' (P1) for Canada and the USA (Klett & Schmoker 2003). Total cumulative production and remaining reserves for the world are shown in Table 5 overleaf.

2.5.2 Reserve growth

Reserve growth in hydrocarbon fields is manifested by the fact that their ultimately recoverable reserves grow through time as additional hydrocarbons e.g. in peripheral areas are discovered and advances in production techniques allow greater recovery.

The known reserves estimated by the USGS WPA for each TPS or group of TPSs are conservative because they do not include reserves growth in existing fields. Consequently, 'grown' reserve estimates for existing hydrocarbon fields, which include projected reserve growth over a period of 30 years from 1995 until 2025, have been made in the USGS WPA and USGS NOGA. These estimates were derived using a statistical approach and a range of estimates is provided. Mean total reserve growth for the world is shown in Table 5 below.

2.5.3 Undiscovered reserves

When a petroleum province is immature from an exploration point of view a significant number of as yet undiscovered fields remain to be found. In the WPA and the NOGA, the USGS provides estimates of the undiscovered petroleum resources in each TPS. Mean total estimated undiscovered petroleum is shown in Table 5 below. The F95 and F5 fractiles indicate that there is at least a 95% chance and 5% chance respectively of the volumes tabulated being present.

Table 5 – World level summary petroleum estimates

	Oil (Billion barrels)				Gas (Billion Cubic Metres)				NGL (Billion Barrels)			
	F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
World (excluding United States)												
Undiscovered conventional	334	607	1,107	649	65	123	231	132	95	189	378	207
Reserve growth conventional	192	612	1,031	612	30	94	157	94	13	42	71	42
Remaining reserves				859				131				68
Cumulative production				539				25				7
Total				*2,659*				*382*				*324*
United States												
Undiscovered conventional	66		104	83	11		20	15	Combined with oil			
Reserve growth conventional				76				10	Combined with oil			
Remaining reserves				32				5	Combined with oil			
Cumulative production				171				24	Combined with oil			
Total				*362*				*54*				
Global total				**3,021**				**436**				

Source: USGS WPA 2000 and Klett & Schmoker 2003

[7] TPS are discussed in detail in Section 2.7.1

2.5.4 Reserves estimates used in this study

It was decided that 'grown' reserves figures should be used in this study because they allow for reserve growth in discovered fields since 1995 and up to 2025. It was considered inappropriate to use the known reserves alone because it was considered likely that significant reserves had been added to the known fields in the period 1996 to 2008. Examples of giant gas fields in which substantial additional reserves have been proved up and brought on stream between 1996 and 2008 include the Viking field in the UK sector of the North Sea.

Using similar reasoning as for reserve growth, it was decided to include the estimates of undiscovered resources in this study, even though it was uncertain when these discoveries had been/would be made, when they could be brought on stream and when they would be depleted and thus become available for CO_2 storage. It was considered that many such fields might be discovered and depleted before the end of the project time frame (2050) and therefore they should be included in the analysis. Examples of giant gas fields that were discovered and brought into production between 1995 and 2008 include the Ormen Lange field in the Norwegian sector of the North Sea, which was discovered in 1997 and production began in 2007. Other examples are the Io, Jansz, Pluto, Wheatstone and Ichthys fields off the north-west coast of Australia, which were discovered after 2000 and from which production is expected to commence in the period 2010-2015. Thus the reserves estimates used in this study comprise the combined 'grown' field reserves plus 'undiscovered' resources.

2.5.5 Estimating 'gas in gas fields'

As mentioned in section 2.4.1 above, the gas-to-oil ratio is used to exclude the volume of associated gas from estimates of global gas reserves to ascertain the volume of gas in gas fields. For the global summary estimates, ideally the weighted mean of the gas-to-oil ratios in all oil fields should be used. As this is not available, the mean value used in the USGS WPA of 2,200 cubic feet of gas per barrel of oil has been used. This is calculated from the ultimately recoverable volumes reported by Petroconsultants (1996). The estimated 'total gas in gas fields' for each fractile is shown in Table 6 below.

Table 6 – Calculation of 'gas in gas fields'

	Based on F95 estimate of gas & oil reserves	Based on mean estimate of gas & oil reserves	Based on F5 estimate of gas & oil reserves
Mean global gas-oil ratio	2,200	2,200	2,200
Assumed GEF	200	200	200
Assumed CO_2 storage density	0.7 t m^3	0.7 t m^3	0.7 t m^3
Global gas	301,359 10^9 m^3	436,165 10^9 m^3	603,653 10^9 m^3
Gas in oil fields	141,371 10^9 m^3	188,224 10^9 m^3	244,174 10^9 m^3
Gas in gas fields	159,989 10^9 m^3	247,941 10^9 m^3	359,479 10^9 m^3
Gross CO_2 storage capacity in gas fields	560 Gt	868 Gt	1,258 Gt
Volume available in gas fields to store CO_2	420 Gt	651 Gt	944 Gt

For the more detailed breakdown, the USGS WPA includes estimates of the minimum, maximum and median gas-oil ratio of undiscovered oil fields in each AU.

These figures were used to assign part of the 'grown plus undiscovered' gas to oil fields. These figures are the best proxy for the weighted mean gas-to-oil ratio in each AU that is available. However, the estimated median gas-to-oil ratio values for each AU will differ from the weighted mean gas-to-oil ratio for each AU, introducing error into the detailed estimates. Thus both the global summary estimates and the more detailed breakdown use different, and less than ideal measures, of gas-to-oil ratio and therefore they produce slightly different results. It is likely that the global summary estimate is the more accurate total because it is based on the reported mean gas-to-oil ratio of all fields.

2.5.6 Minimum CO_2 storage capacity cut-off

As mentioned in section 2.4.3, this analysis removes the capacity from fields that are considered to be too small for CO_2 storage. The cut-offs considered appropriate in this study are 50 and 100 $MtCO_2$ storage capacity onshore and offshore respectively.

Field-level data on the estimated CO_2 storage capacity of gas fields in Europe was kindly made available to the study by the EU 6th Framework Programme Geocapacity Project partners. In this study full country evaluations were carried out for Bulgaria, Croatia, Czech Republic, Estonia, Hungary, Italy, Latvia Lithuania, Poland, Romania, Slovakia, Slovenia and Spain. Neighbour country reviews were carried out for Albania, Macedonia (FYROM), Bosnia-Hercegovina and Luxembourg, and country updates were made for Germany, Denmark United Kingdom, France and Greece. The effect on the total CO_2 storage capacity in gas fields in the Geocapacity Project of various cut-offs is shown in Table 7 overleaf.

Table 7 – Effect of minimum storage capacity cut-offs on total storage capacity

	Onshore gas fields		Offshore gas fields	
Cut-off $MtCO_2$ storage capacity	Total capacity below cu-toff	%	Total capacity below cut-off	%
10	321	7%	480	5%
20	380	9%	980	10%
30	1,383	31%	1,977	21%
40	1,628	37%	2,368	25%
50	1,852	42%	2,810	29%
60			3,030	32%
70			3,484	36%
80			3,561	37%
90			3,643	38%
100			3,832	40%
All fields	4,417		9,614	

Source: Geocapacity Project

Although it is recognised that the Geocapacity project data is not necessarily representative of the rest of the world, this data is the only large field-level dataset available to the study, and it does have the advantage that it includes both onshore and offshore fields. Consequently a decision has been taken to discount the onshore and offshore components of the storage capacity by 40% to remove capacity that is in fields that are too small for economically realistic CO_2 storage.

2.5.7 Other adjustments to the estimate of CO_2 storage capacity in gas fields

This part of the analysis has not taken account of the distance between CO_2 sources and sinks or the CoP date of the sinks, on the basis that the storage capacity is not based on actual fields but the aggregate capacity of fields spread over a large area and hence distances to sources and CoP dates will vary. Instead we have applied these factors to our analysis of the giant gas fields, which is detailed in section 3.

2.6 Estimating global CO_2 storage capacity in gas fields

The coefficients discussed above have been applied to the estimates of the theoretical and effective CO_2 storage capacity detailed in Table 6 above. The F95 and F5 fractiles shown in Table 8 below indicate that there is at least a 95% chance and 5% chance respectively of the volumes tabulated being present. Applying the same CO_2 storage calculation coefficients to the F95 and F5 fractiles provides an indication of the potential range of possible global CO_2 storage capacity in gas fields. However, any inaccuracy in the coefficients used will introduce further uncertainty to the estimates of CO_2 storage capacity.

Table 8 – Estimates of global CO_2 storage capacity in gas fields (Gt)

Capacity	Adjustment	Based on F95 estimate of gas & oil reserves	Based on mean estimate of gas & oil reserves	Based on F5 estimate of gas & oil reserves
Theoretical		560	868	1,258
Effective	75% of Theoretical	420	651	944
Practical	Adjust for size of field (60% of Effective)	252	391	566
	Account for unsuitable fields (Reduce by 1%)	249	387	561

Source: USGS Global Assessment

2.7 Regional estimates of CO_2 storage capacity in gas fields

The USGS global estimates used in the above analysis is not available by region, meaning it cannot be used to provide storage capacity estimates by region. However, it is possible to use data on the Total Petroleum System (TPS) based on Assessment Units (AU) to provide estimates of regional storage capacity.

There are slight differences between these data sets, probably because associated gas in the analysis based on Assessment Units has been under estimated.

The total estimate of effective storage capacity based on the TPS data is 673 Gt, which is slightly greater than the estimate of 651 Gt based on the USGS global estimates. Our view is that our analysis of the USGS global estimates is likely to be more reliable, because the arithmetic mean global gas-to-oil ratio is used, and hence we have used the figures derived from them in our estimates. However, we consider that our analysis based on the USGS Assessment Units is still useful because it provides estimates of CO_2 storage capacity by region.

The following provides an overview of the TPS data followed with regional estimates of storage capacity.

2.7.1 Total Petroleum Systems

The USGS WPA and the USGS NOGA assess petroleum resources on the basis of Total Petroleum Systems (TPSs)[8]. A TPS comprises:

- the essential elements of a petroleum system, including the source, reservoir, seal, and overburden rocks;
- all the processes that generate petroleum, including generation, migration, accumulation and trap formation; and
- all genetically related petroleum that occurs in seeps, shows, and accumulations, both discovered and undiscovered, whose provenance is a pod or closely related pods of active source rock.

A TPS is therefore 3-dimensional and can overlap with other TPSs. Each Total Petroleum System is divided into one or more AU which are the basis of the USGS analysis.

The regional and local scale analysis of CO_2 storage capacity in gas fields in this study is based as far as possible on the USGS AU level data. However, it is reported mainly at the TPS level for the world excluding the USA (for clarity of illustration) and at the Province[9] level within the USA, because the publicly available data is less complete at the AU level for the USA.

For the purposes of this study, certain TPSs have been grouped together, either because they overlap, or because they form a closely associated geographical group, or both[10]. These groupings are summarised in Annex A.

2.7.2 Estimating reserve growth in AUs

In this study, the ratio of grown to known reserves in USGS WPA tables' gdisc.tab and kdisc.tab was derived for many TPSs[11]. For other TPSs where gas fields are present but no ratio could be derived from the above tables, an average 'grown' to 'known' ratio of 1.4:1 was used.

Several TPSs evaluated by the USGS do not contain any discovered gas fields and are not included in this study.

2.7.3 Estimating undiscovered resources in AUs

Estimates of undiscovered resources by AU used in this study were taken from the USGS WPA table auvol.tab[12].

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8 See http://energy.cr.usgs.gov/WEcont/chaps/PS.pdf.

9 A Province is a domain with a set of geological characteristics distinguishing it from surrounding provinces. These characteristics may include the dominant lithologies, the age of the strata and the structural style. Some provinces may include multiple genetically-related basins.

10 A map of all TPSs worldwide is available at http://certmapper.cr.usgs.gov/website/worldmaps/viewer.htm?Service=WorldEnergyByTPS&OVMap=world_overview&extent=auto.

11 These tables are available at http://energy.cr.usgs.gov/oilgas/wep/products/dds60/tables.htm.

12 Available at http://energy.cr.usgs.gov/oilgas/wep/products/dds60/tables.htm.

2.7.4 Estimates of regional CO_2 storage capacity in depleted gas fields

Table 9 below shows the estimates of storage capacity by region based on the TPS data. A comparison with the estimates based on the USGS Global Assessment in Table 8 above show that they are very close although those based in the TPS data are slightly higher. Table 9 indicates that the regions with the greatest potential for storing CO_2 in depleted gas fields are the Former Soviet Union and the Middle East and Africa.

Table 9 – Estimates of regional CO_2 storage capacity in gas fields (Gt)

Region	Theoretical	Effective	Practical
Asia-Pacific	101	75	45
Central and South America	60	45	27
Europe	83	62	37
Former Soviet Union	341	256	152
North America	75	56	33
Middle East & Africa	238	178	106
Total	**897**	**673**	**400**

Source: USGS Total Petroleum System data

Tabulated estimates of the gross CO_2 storage capacity for individual provinces are given in Annex B.

2.8 Comparison with previous estimates of CO_2 storage capacity in gas fields

The Initial Study estimated the global CO_2 storage capacity of natural gas fields to be 797 $GtCO_2$. This estimate corresponds to the estimate of effective capacity in the present study, which is 651 $GtCO_2$. There are two main differences between the effective capacity estimates used in this study and that used in Initial Study:

- The method of estimating the space available for CO_2 storage in a depleted gas field differs slightly. The Initial Study estimated the reservoir volume of ultimately recoverable gas reserves in petroleum provinces by assuming representative temperature and pressure gradients and average depths for fields in each province. The mass of CO_2 that could be stored in that volume was then estimated using the same reservoir temperature and pressure. In the current study a global average gas expansion factor and reservoir CO_2 density were used to estimate the reservoir volume occupied by the ultimately recoverable gas reserves and the mass of CO_2 that could be stored in that volume respectively.
- This study explicitly takes account of the fact that a proportion of the total global gas resource is associated gas found in oil fields, whereas this does not appear to be explicitly accounted for in the Initial Study.

The estimate of CO_2 storage capacity in oil and gas fields in IPCC (2005) is 675 to 900 $GtCO_2$ when undiscovered fields are excluded from the analysis. The estimate would increase by approximately 25%, i.e. to 844 to 1125 $GtCO_2$, if undiscovered fields were included (IPCC 2005). Bearing in mind that these figures include storage potential in oil fields as well as gas fields, they are compatible with the current estimates, even if they cannot be compared directly.

3. COST OF CO_2 TRANSPORT AND STORAGE

3.1 Overview

The main elements of CO_2 transport and storage addressed here include the following:

- onshore and offshore pipelines;
- boosting, both pumping and compression;
- onshore and offshore injection surface facilities at sink location;
- onshore and offshore injection wells; and
- monitoring of storage integrity.

Full drying, limiting of impurities, and metering of the CO_2 are assumed to have taken place at the source capture facility, and are not covered by the costs in this study.

3.2 Pipeline Systems

3.2.1 Onshore Pipelines

CO_2 has been transported onshore by pipeline for over 30 years, primarily in the USA as part of EOR projects, where over 2,500km of pipelines are in service. CO_2 is most efficiently transported by pipeline in the dense phase, above 60 to 80 bar pressure, depending on temperature and impurity levels. In this phase CO_2 has the density of a liquid but the viscosity and compressibility of a gas.

Onshore pipeline costs used in this study are based on the recent IEA GHG Study 2007/12 *Distributed Collection of CO_2*, which presents mid-2007 costs for a range of pipeline diameters for the UK, including some benchmarking against recent project costs.

Intermediate boosting stations and block valves are included with the capital and operating expenditure. The boosting costs assume that the CO_2 is in the dense phase, and hence requires pumping rather than compression.

The analysis used a maximum pressure in onshore pipes of 150 bar and a minimum pressure of 85 bar.

3.2.2 Offshore Pipelines

To date only one offshore CO_2 pipeline has been put into service, but this is due to a lack of demand rather than any technical barrier. An 8-inch offshore CO_2 pipeline to a subsea injection well has been installed in Norway as part of the Snøhvit project, and injection commenced in April 2008.

An advantage of offshore pipelines for CO_2 transportation is that higher design pressures can be used than onshore, potentially up to 300 bar. This is partly due to the reduced hazard to population compared to onshore routes, which allows higher design factors to be used; and partly due to the compensatory effects of external hydrostatic pressure, particularly in deep water.

The analysis used a maximum pressure in offshore pipes of 250 bar and a minimum pressure of 85 bar.

3.2.3 Potential to Reuse Existing Pipelines

There is an extensive network of oil and gas pipelines around the world, which presents a significant opportunity for re-use as part of CO_2 storage infrastructure. In principle these existing pipelines, the vast majority of which are carbon steel, are metallurgically suitable to carry CO_2 provided that the moisture content is maintained at a sufficiently low level, approximately 500 ppm. The main limitation of existing lines is design pressure, which for oil and gas transmission service typically varies between 90 and 180 bar. The effect of this limitation is to reduce transportation capacity compared to a purpose-built new line, which would likely be designed for a higher pressure. The second uncertainty regarding existing lines is remaining service life. Many existing pipelines have been in operation for between 20 and 40 years. Remaining service life can only be assessed on a case-by-case basis, taking into account internal corrosion, and the remaining fatigue life.

Therefore for the purposes of this study, reuse of existing pipeline systems has not been considered.

3.2.4 Landfall Terminals

For transmission pipelines which transit both onshore and offshore routes, a landfall terminal is assumed for costing purposes at the coast. The CO_2 export facility would comprise a combination of compression and pumping to boost the CO_2 stream to the offshore pipeline operating pressure.

3.3 Injection Facilities

3.3.1 Onshore Injection Facilities

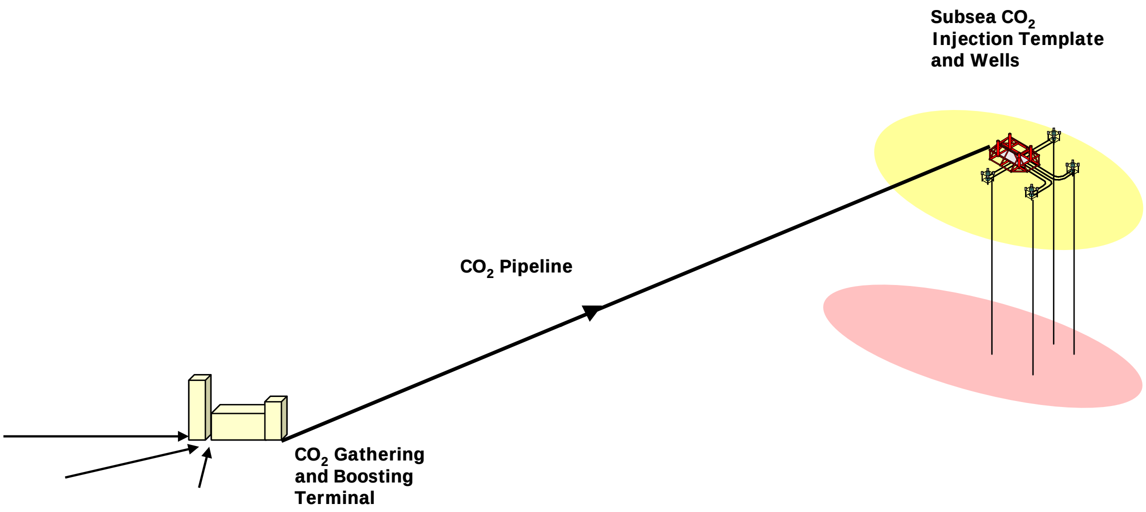
Onshore injection facilities will typically include the following components:

- a number of wellsites, each with an injection wellhead, which may be spread over a sizeable geographic area;
- a network of distribution flowlines to the wellsites;
- a manifold and control valves connecting the arriving CO_2 transmission pipeline with the distributing flowlines;
- booster pumps if required;
- controls and instrumentation;
- utilities such as power generators; and
- a control room and associated buildings, such as offices, workshop, stores etc.

3.3.2 Offshore Injection Facilities

At each offshore sink location a facility is required to distribute the CO_2 arriving by pipeline between the wellheads of the injection wells. In its simplest form, CO_2 arrives at a suitable pressure for injection and only one or two wells are involved. The facility could then be a subsea wellhead located on the seafloor with valving to control fluid distribution, as illustrated in Figure 5 overleaf. Such technology is commonplace in oil and gas production, and this is the configuration adopted in the Snøhvit CO_2 injection project.

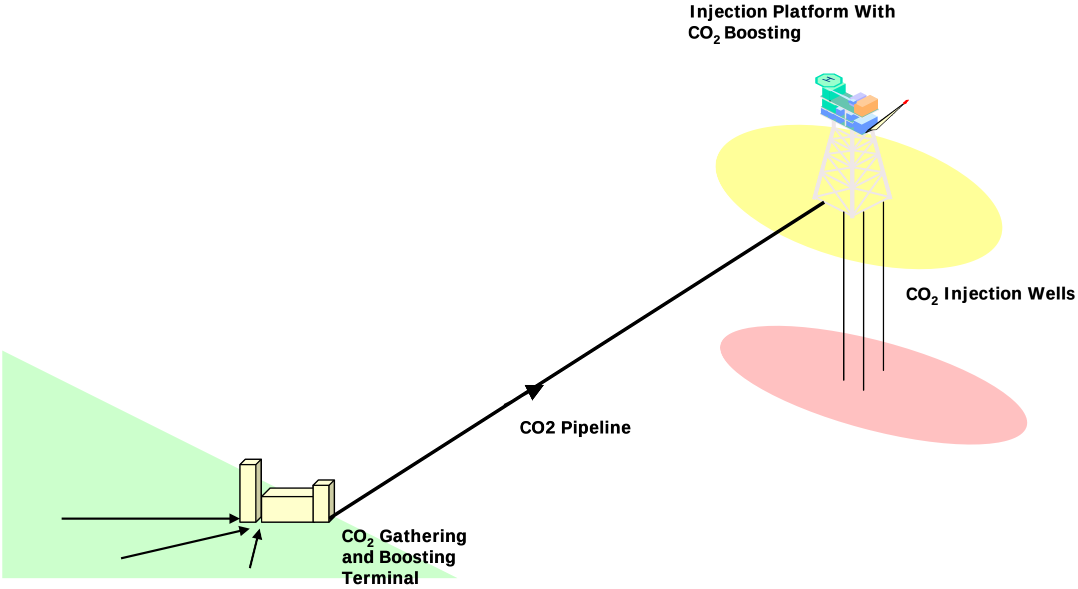
Figure 5 – Offshore injection if no infield boosting is required



For larger numbers of injection wells, there are associated benefits in locating the CO_2 injection wellheads on a surface platform, above the waterline, in terms of ease of access downhole for maintenance and repairs. This factor is likely to drive any offshore development involving more than three to four wells towards a surface platform rather than subsea.

The appropriate surface facility concept will vary with water depth. By analogy with offshore oil and gas facilities, fixed platforms are typically more economic up to 100m depth. Between 100 – 200m either fixed or floating facilities are in use, with other factors dictating the preference. Over 200m water depth, floating facilities are most often used. For this study, the breakpoint between fixed and floating platforms is taken as 200m. An injection scenario based on a fixed platform is illustrated in Figure 6 overleaf.

Figure 6 – Offshore injection if infield boosting is required up to 200m water depth

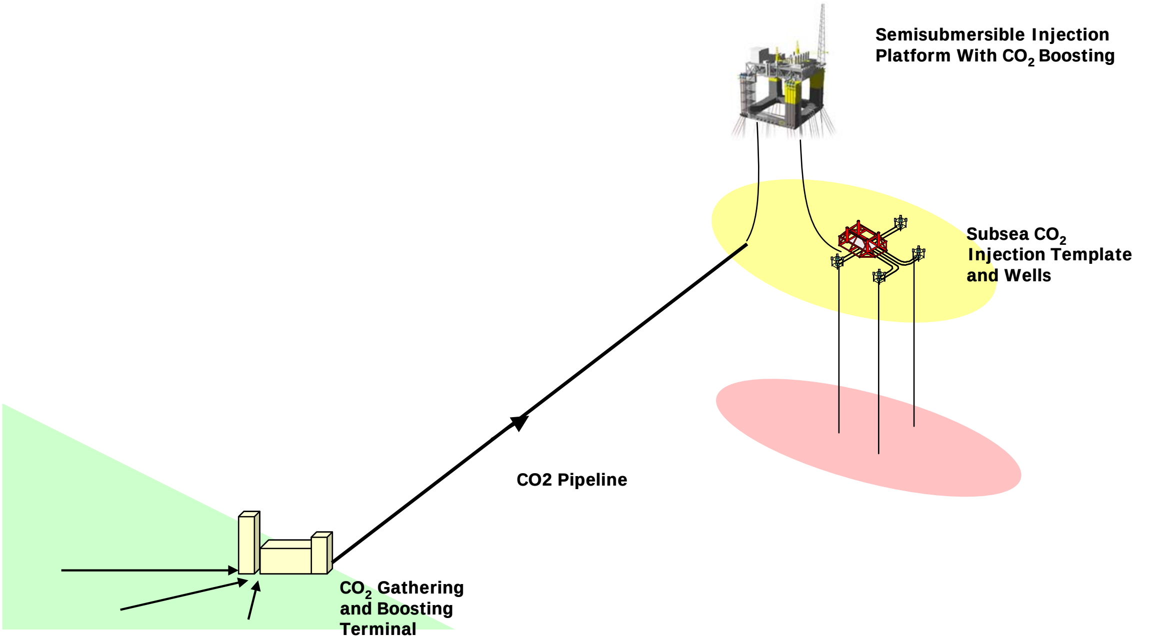


For deepwater floating platforms, alternative hull concepts are available based on either

- surface wellheads, called 'dry tree' units such as Tension Leg Platforms or Spars; or
- subsea wellheads, called 'wet tree' units such as semi-submersibles and ship shape hulls.

An injection scenario based on a floating platform is shown in Figure 7 overleaf.

Figure 7 – Offshore injection if infield boosting is required over 200m water depth



3.3.2.1 *Offshore Boosting*

For the purposes of the study it is assumed that offshore pipelines do not include intermediate boosting, due to the relatively high cost of providing such facilities (which would need to be manned). This is normal practice in the oil and gas industry, where offshore gas pipelines can be designed to exceed 500km without intermediate compression. Pipelines in the study network model are sized and costed on the basis of 250 bar inlet pressure and 85 bar arrival pressure at the injection site.

For injection of CO_2 into a depleted gas reservoir, boosting at the surface facility is not initially required, as the assumed arrival pressure of 85 bar plus the static head of CO_2 in the well tubing provides sufficient injection pressure downhole (see section 3.4.1). This is of considerable advantage offshore is it allows a simpler, unmanned, surface facility or a totally subsea facility to be used. On specific projects initial boosting at the surface may allow a reduction in the number of injection wells, and this optimisation would be analysed on an economic basis, but this effect cannot be generalised and therefore has not been considered in the study model. Later in life as the reservoir fills, the addition of boosting at the surface may also deliver benefits in terms of maintaining the injection rate and allowing more CO_2 to be stored; again this effect cannot be generalised and has not been considered in the study.

3.3.2.2 *Suitability of Existing Offshore Platforms*

There are existing production platforms located over most offshore fields which could potentially be adapted to enable injecting CO_2 into the depleted reservoir. Existing gas compression and oil pumping systems are not suitable for boosting of CO_2 if this is required. As with re-use of pipelines, there is also the uncertainty of residual life of the support structure of any platform, given that some may be a year or two old and others may be approaching 40 years old.

Another uncertainty is the ability of an existing platform to accommodate newly drilled CO_2 injection wells, or to offer existing production or water injection wells which can be adapted for CO_2 injection. This is a complex issue and the study has adopted a simplified assumption of no re-use of existing wells.

3.3.3 Injection Facility Costs

Table 10 below summarises order-of-magnitude costs for new injection facilities, covering a range of well numbers and water depths, and were prepared on the following basis:

- averaged materials, equipment and construction costs over the period 2004 to 2008;
- no allowance for regional cost variations;
- drilling and completion costs of injection wells are excluded, as they are addressed separately below; and
- costs do not include contingency allowances or account for other risks.

Table 10 – Estimates of new injection facility costs

Sink Category	Onshore	Water Depth up to 100m	Water Depth 100 - 200m	Water Depth 200 - 1,000m	Water Depth > 1,000m
Facility Type	Onshore wellsite	New fixed injection platform with jackup drilling.	New fixed injection platform with onboard drilling.	New floating injection platform without onboard drilling and subsea wells.	New floating injection platform without onboard drilling and subsea wells.
Nominal water depth (m)		50	150	500	2,000
Injection Only	$30m + $2m per well	$120m	$200m	$250m	$300m
Injection + Boosting	$60m + $4m per well	$200m	$300m	$400m	$450m

Note: The cost of drilling wells is not included in this table.

3.4 Injection Wells

3.4.1 Number and Configuration of Wells Required

The optimum number and configuration of CO_2 injection wells for a given field are heavily dependent on the reservoir geometry and physical characteristics, such as faulting, porosity and permeability, which vary widely from field to field. Therefore in a study such as this, only broad generalisations can be made.

We have used the method McCollum and Ogden (2006) proposed to determine the number of wells for each sink. This method recognises that CO_2 properties vary significantly with pressure and temperature, and that in a typical injection scenario the CO_2 will expand rapidly from the well completion, or 'foot' of the well, as it permeates a depleted reservoir. The method determines the CO_2 mobility and injectivity at an intermediate point between the well completion and average reservoir conditions, and this is used to calculate the flow capacity of an individual well. A range of reservoir scenarios was constructed covering the principal variables of reservoir depth and water depth for offshore fields, see Table 11. Average values were taken for reservoir thickness, permeability and porosity. The flow capacity of a single well was calculated, assuming a standard nominal 5-inch tubing size. This capacity was then used in the main costing model to calculate the required number of injection wells for each field in the database.

Table 11 – Estimates of well flowrates

			Reservoir Parameters										CO_2 Injectivity				Well Flowrate	
Case ID	Reservoir Classification	Location	Water depth (m)	Depth (m)	Initial Pressure MPa	Max Pressure MPa	Thickness (m)	Permeability (md)	Temperature (°C)	Est Pressure Down (Mpa)	Choke at completion	Pinter (Mpa)	Visc inter (mPa-s)	CO_2 Mobility	CO_2 Injectivity	Q per well (tonnes/day)	Q per well (mtpa)
A	Reservoir 0 - 1000m	Onshore	0	500	1.3	6.6	31	10	28	12.8	Yes	3.9	0.02	342.3	7.1	2,549	0.93
B	Reservoir 0 - 1000m	Offshore 0 - 200m	100	600	1.5	7.9	31	10	30	13.6	Yes	4.7	0.02	342.3	7.1	2,671	0.98
C	Reservoir 0 - 1000m	Offshore 200 - 1000m	600	1,100	2.8	14.6	31	10	43	17.9	Yes	8.7	0.03	219.1	4.6	2,140	0.78
D	Reservoir 1000 - 2000m	Onshore	0	1,500	3.8	19.9	31	10	53	21.4	Yes	11.8	0.04	136.9	2.8	1,558	0.57
E	Reservoir 1000 - 2000m	Offshore 0 - 200m	100	1,600	4.0	21.2	31	10	55	22.2	Yes	12.6	0.04	136.9	2.8	1,607	0.59
F	Reservoir 1000 - 2000m	Offshore 200 - 1000m	600	2,100	5.3	27.8	31	10	68	26.5	No	15.9	0.04	127.4	2.6	1,745	0.64
G	Reservoir 2000 - 3000m	Onshore	0	2,500	6.3	33.1	31	10	78	29.9	No	18.1	0.04	130.4	2.7	1,989	0.73
H	Reservoir 2000 - 3000m	Offshore 0 - 200m	100	2,600	6.5	34.4	31	10	80	30.7	No	18.6	0.04	130.4	2.7	2,035	0.74
J	Reservoir 2000 - 3000m	Offshore 200 - 1000m	600	3,100	7.8	41.1	31	10	93	35.0	No	21.4	0.04	130.4	2.7	2,291	0.84
K	Reservoir 3000 - 4000m	Onshore	0	3,500	8.8	46.4	31	10	103	38.4	No	23.6	0.04	124.5	2.6	2,380	0.87
L	Reservoir 3000 - 4000m	Offshore 0 - 200m	100	3,600	9.0	47.7	31	10	105	39.2	No	24.1	0.04	124.5	2.6	2,424	0.89
M	Reservoir 3000 - 4000m	Offshore 200 - 1000m	600	4,100	10.3	54.3	31	10	118	43.5	No	26.9	0.04	124.5	2.6	2,669	0.97
N	Reservoir 4000 - 5000m	Onshore	0	4,500	11.3	59.6	31	10	128	46.9	No	29.1	0.04	127.4	2.6	2,928	1.07
P	Reservoir 4000 - 5000m	Offshore 0 - 200m	100	4,600	11.5	60.9	31	10	130	47.7	No	29.6	0.04	127.4	2.6	2,973	1.09
Q	Reservoir 4000 - 5000m	Offshore 200 - 1000m	600	5,100	12.8	67.5	31	10	143	51.9	No	32.3	0.04	127.4	2.6	3,216	1.17

It should be noted that for shallower reservoir scenarios (less than 1,600m total vertical depth) it is necessary to choke the flow of CO_2 at the well completion in order avoid over-pressuring the reservoir formation above the calculated fracture gradient. If the wellhead surface pressure was reduced to avoid the need for a choke, the reduced back-pressure from the reservoir into the tubing would take the CO_2 in the tubing into the gas phase, and the associated friction loss would prevent CO_2 flow.

3.4.2 Well costs

Injection well costs are a function of the following:

- rig dayrate for:
  - onshore,
  - offshore less than100m water depth by jackup,
  - offshore 100 to 1,000m by 3rd generation semi-submersible,
  - offshore more than 1,000m by 5th generation semi-submersible
- drilling depth, which is assumed to be the reservoir depth;
- deviation, which is assumed to be vertical for onshore and 30° for offshore;
- type of rock is classed as either soft, medium or hard and assumed to be medium where no data is available;
- materials and consumables, such as casing, tubing, mud and chemicals etc; and
- logistics support, project management and engineering.

Drilling spread day rates are based on averaged values over the period 2004 to 2008. It was considered inappropriate to use 2008 rates for longer range forecast costs, as they were clearly at a market peak. The costs of rig and equipment mobilisation and demobilisation are assumed to occur once per sink, that is all wells required are assumed to be drilled in one campaign. Well costs used in the study are shown in Table 12 below.

Table 12 – Well costs by depth and rig type

	Rig Type	Land Rig	Jackup Rig	Platform based	2nd/3rd Generation Semisub	4th/5th Generation Semisub
Reservoir Depth 1 km	Drilling Days	25	25	25	25	25
	Total Cost Per Well ($m)	4.2	7.0	5.6	12.6	19.6
	Mob/Demob per Facility ($m)	6.4	7.1	6.7	8.5	10.2
Reservoir Depth 3 km	Drilling Days	50	50	50	50	50
	Total Cost Per Well ($m)	11.2	16.8	14.0	28.0	42.0
	Mob/Demob per Facility ($m)	6.4	7.1	6.7	8.5	10.2
Reservoir Depth 5 km	Drilling Days	150	150	150	150	150
	Total Cost Per Well ($m)	22.4	39.2	30.8	72.8	114.8
	Mob/Demob per Facility ($m)	6.4	7.1	6.7	8.5	10.2

3.4.3 Potential to Reuse Existing Wells

In some cases, existing production or injection wells may be re-used, with little costs except above those required for wellbore and completion integrity assessment and possible remedial work. It is difficult to quantify how many wells may be re-used for any specific sink, although industry experts consider 50% re-use may be a good starting approximation.

For the purposes of this study all wells are conservatively assumed to be newly constructed for CO_2 injection service.

3.5 Monitoring of Storage Integrity

Storage integrity monitoring is an important element in any CO_2 sequestration project. The costs of monitoring will vary widely depending on if the field is onshore or offshore, and whether existing wells can be used to monitor reservoir conditions, or if new monitoring wells are required.

Ongoing costs may include condition monitoring through existing or new wellbores, and may in some cases include periodic 3D seismic surveys to observe progress of the CO_2 front through the reservoir, plus analysis and interpretation. Given the wide variance in the cost of these example monitoring methods, it is clear that the monitoring cost will vary widely by field type and location.

Monitoring costs are likely to be small relative to the facilities capital and operating costs, and there is also little precedent to date due to the very small number of operating projects. This study has adopted a somewhat notional cost of US$ 0.30 per tonne of CO_2 stored, based on Chapter 8 in the IPCC Special Report Carbon Capture Storage Report (2005).

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4. CO_2 STORAGE CAPACITY IN DEPLETED GIANT GAS FIELDS

4.1 Introduction

This Section investigates the impact that the distance between large CO_2 sources and gas fields and the date at which gas fields become available has on CO_2 storage capacity. To match actual sources with actual gas fields, we have used the following:

- large stationary sources emitting more than 1 $MtCO_2$ pa listed in the IEA GHG (2008); and
- giant gas fields listed in the *Giant Fields Atlas* (2008).

These data sources are outlined in more detail below.

To take account of when the giant gas fields will become available for CO_2 storage, we have estimated the CoP dates, as these are not typically publicly available. To lessen the impact of any inaccuracy in these estimates, and for the modelling to be manageable, we have grouped CCS projects into decades, starting with 2011 and progressing through to 2050.

In this approach, we have assumed that operators will be aware of which sources will be connected to sinks within each decade but not for subsequent decades. Consequently, the network infrastructure will be configured to transport and inject the CO2 from capture projects commissioned within the decade and will not take account of any CO2 that may be captured in later periods.

The analysis of connecting sources with sinks considered a total of 2,636 large stationary CO_2 sources and 365 potential sinks. The terms of reference for this study stipulated that capture costs, oilfields, and saline aquifers where not to be considered. These are clearly very important factors that will dictate overall CCS uptake and costs.

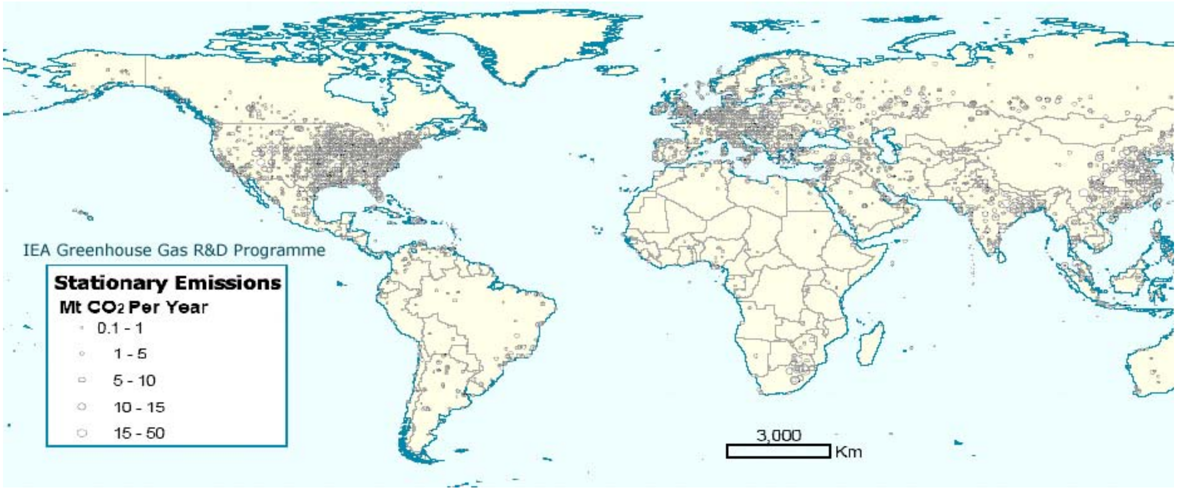
4.2 Data on sources of CO_2

The IEA GHG has developed a *CO_2 Emissions Database*, which contains details of major sources CO_2, including:

- name of source;
- location in terms of country and latitude and longitude;
- which of 13 sectors it belongs;
- capacity, hours of operation and annual emissions;
- percentage of CO_2 in flue gases; and
- expected growth in emissions.

Figure 8 contains a world map showing the location and size of the sources from the IEA GHG's *CO_2 Emissions Database*.

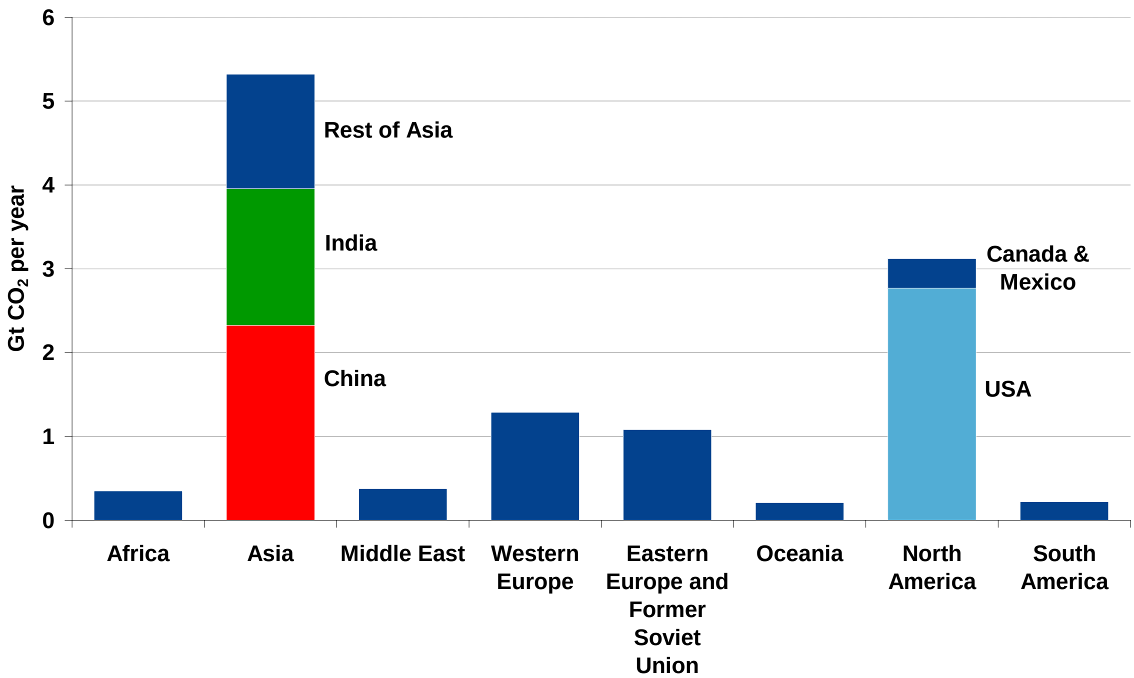
Figure 8 – Map detailing stationary CO_2 emission sources



Source: IEA GHG R&D Programme www.co2captureandstorage.info

Growth rates in emissions have been applied to the historical emissions, both from the IEA GHG's *CO_2 Emissions Database* to estimate future emissions by region. Figure 9 below shows expected annual CO_2 emissions from large stationary sources in 2011 to 2020 by region.

Figure 9 – Average CO_2 emissions from large stationary sources by region in 2011 to 2020



Source: www.co2captureandstorage.info

4.3 Description of giant gas fields

4.3.1 Overview

Approximately 65% of the discovered oil and gas in the world is contained in a relatively small number of giant fields (Halbouty 2003). Two databases of giant oil and gas fields worldwide were available for the study:

- the American Association of Petroleum Geologists' (AAPG) database of giant oil and gas fields worldwide given in Halbouty (2003); and
- a database partly based on the AAPG database and containing several additional giant gas fields Horn (2008), which was used to supplement the data given in Halbouty (2003).

The information on giant gas fields used in this study comes from the *Giant Fields Atlas* (2008), which provides information on gas fields that once contained recoverable gas reserves greater than 1.5 tcf, or 42 bcm, which corresponds to storage capacity of approximately 100 $MtCO_2$. The information provided includes the:

- name of the fields;
- location of the fields;
- year of discovery;
- ultimate recoverable oil, gas and condensate; and
- reservoir depth.

Reserves figures for giant fields given in the AAPG database (Halbouty 2003) are provided on an 'as reported' basis. For the fields in the USA and Canada these figures represent proven reserves. For the fields elsewhere in the world, the assumption is that the figures represent proven plus probable (P2) figures, and thus the USGS TPS data and the giant field data are strictly speaking not comparable outside North America. Nevertheless, they are the best data available. Like the USGS, the AAPG define a gas field as a hydrocarbon field with a gas-to-oil ratio of more than 20,000 scf/bbl, which is adopted in this analysis.

The method used to estimate the CO_2 storage capacity of the giant gas fields is essentially the same as that used for the Total Petroleum Systems. An example is given in Table 13 overleaf.

Table 13 – Examples of estimates of storage capacity from URR

Estimate	Adjustment	Pars South (Iran)	Halten Terrace Trondelag Platform
Ultimate Recoverable Reserve (tcf)		350 tcf	7.7 tcf
Ultimate Recoverable Reserve (tm^3)	Divide by 35.31	9.9 tm^3	0.2 tm^3
Reservoir volume URR occupied (bm^3)	Divide by gas expansion factor (200)	49.6 bm^3	1.1 bm^3
Storage capacity for CO_2 ($mtCO_2$)	Multiply by density of CO_2 (0.7 tonnes/m^3)	34,700 $mtCO_2$	760 $mtCO_2$
Volume available for storing CO_2 ($mtCO_2$)	Multiply by 75%	26,000 $mtCO_2$	570 $mtCO_2$

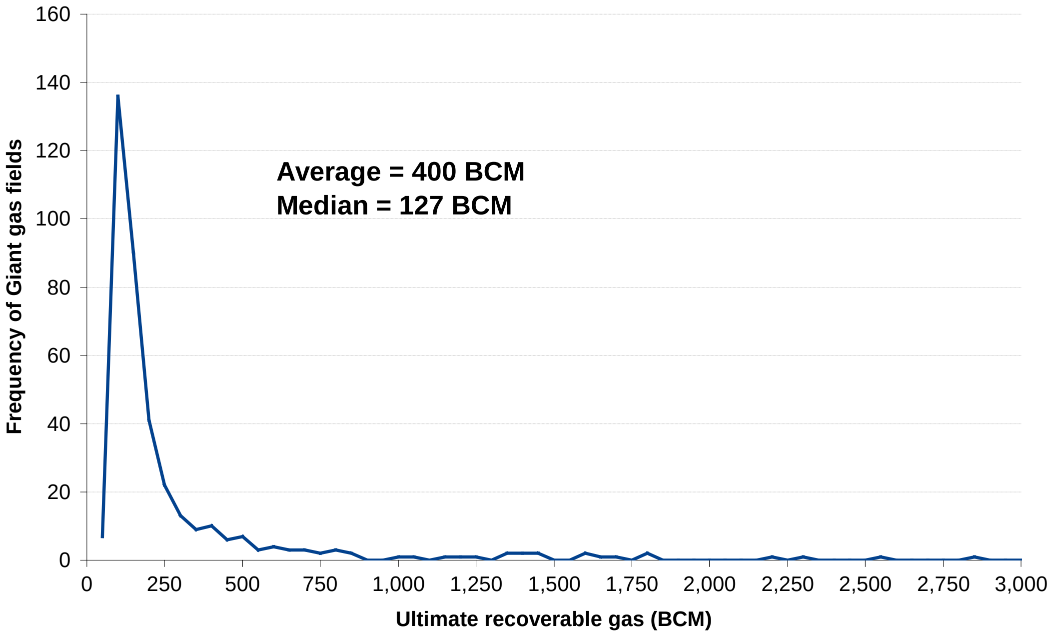
Source: USGS

The Giant Fields Atlas list 391 giant gas fields of which 365 were used, as some are expected to close after 2050 and some were at a depth of less than 800m.

No further technical constraints, such as known faults, compartmentalisation, porosity, permeability, caprock integrity, were applied to reduce the storage capacity, which should therefore be considered an upper limit. No political constraints are applied and no competing use of sites, such as for natural gas storage, is estimated.

The smallest giant gas fields used have recoverable gas reserves of 85 bcm, while the largest has 25,000 bcm. Figure 10 below shows the skewed distribution of giant gas fields.

Figure 10 – Distribution of giant gas fields by size



Source: Giant Fields Atlas

4.3.2 Estimation of close of production dates

The Giant Fields Atlas does not provide details for the CoP dates for the fields, and as these are confidential, and publicly released dates are unreliable, Pöyry Energy Consulting estimated the dates. The approach taken was to use details from known gas fields, which had either ceased production or were close to it, and use measures contained in the Giant Fields Atlas that could predict the CoP date. The two significant factors are the:

- volume of recoverable gas reserves, as the larger the reserves the longer the time required to deplete the field; and
- year of discovery, which indicated that older the fields took slightly longer to deplete, which is probably a function of technological developments.

The parameters from a regression equation using these explanatory variables were applied to estimate a CoP date for each giant gas field. As there is some uncertainty about these dates, we have assumed that CO_2 can start being injected in either the:

- same the decade when the estimate CoP is no more than half way through the decade; or
- following decade when the estimate CoP is more than half way through the decade.

Table 14 – Number of sinks that become available by decade

Decade	Years	Total sinks that become available	Usable sinks that become available
1	2011-2020	134	123
2	2021-2030	126	121
3	2031-2040	63	62
4	2041-2050	59	59
	Beyond 2050	9	-
Total		*391*	*365*

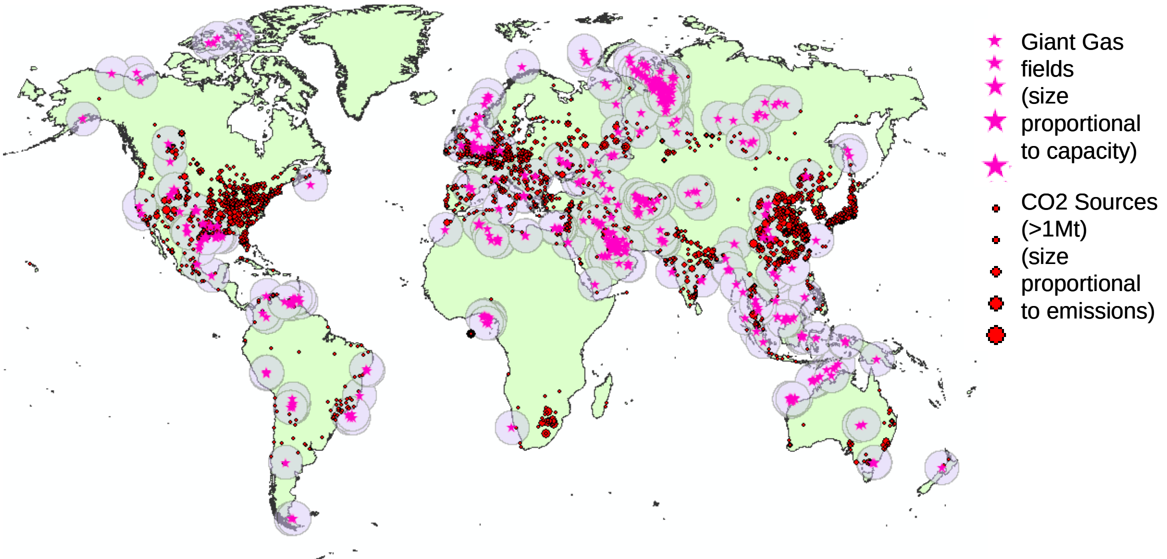
Note: Usable sinks are those more than 800m below the surface and for which the necessary information is available.
Source: Giant Fields Atlas

The majority of storage capacity becomes available before 2030. Publicly announced CCS projects currently number in the low tens, so that availability of suitable gas storage sites due to CoP date is not an immediate or significant restriction at the global level, given a realistic growth rate for CCS up to 2020.

4.4 The global distribution of sources and sinks

We have produced a series of maps that plot CO_2 sources from the IEA GHG Sources Database that emit at least 1 $MtCO_2$ pa and the giant gas fields. Figure 11 below shows the location of large CO_2 sources and the area 500 km from giant gas fields. The analysis indicates that 259 (66%) of giant gas fields are within 500 km of a large CO_2 source.

Figure 11 – CO_2 sources and giant gas fields within circle of 500 km radius



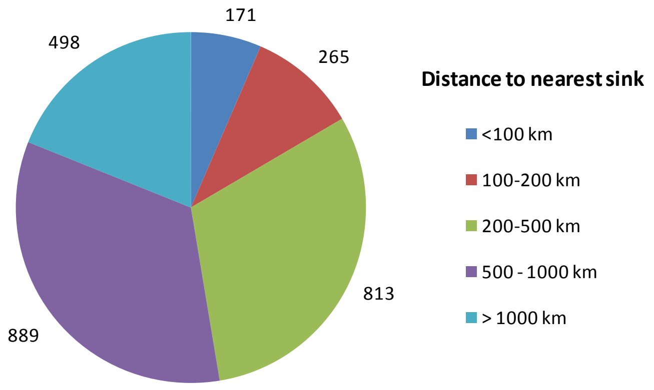
Source: www.co2captureandstorage.info and Giant Fields Atlas

The key points from Figure 11 are that there are a large number of:

- CO_2 sources that are significant distances from a giant gas fields, particularly in:
  - Eastern USA;
  - China;
  - Japan; and
  - parts of central Europe.
- giant gas fields that are significant distances from CO_2 sources, particularly in:
  - The Middle East;
  - large parts of the Former Soviet Union;
  - South East Asia; and
  - Northern North America.

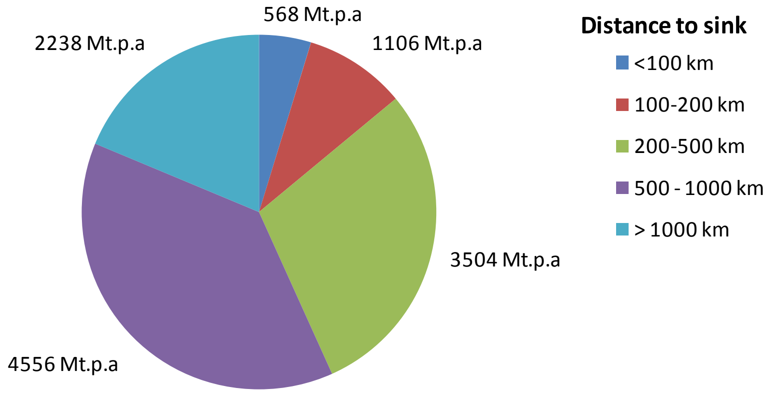
Figure 12 overleaf shows the distribution of the number of sources with emissions greater than 1 $MtCO_2$ pa within a given distance of a giant gas field while Figure 13 overleaf shows the corresponding distribution of CO_2 emissions.

Figure 12 – Number of large CO_2 sources by distance to closest giant gas field



Source: Element Energy, www.co2captureandstorage.info and Giant Fields Atlas

Figure 13 – Distribution of CO_2 emissions from closest giant gas fields



Source: www.co2captureandstorage.info and Giant Fields Atlas

Figure 13 indicates that:

- more than three quarters of sources are within 1,000 km of at least one giant gas field; and
- 43% of global CO_2 emissions originating from large point sources are within 500 km of a giant gas field.

4.5 Connecting large stationary CO_2 sources to sinks

The project developed a GIS-based semi-automatic network connection algorithm to match sources to sinks and thereby generate a CO_2 pipeline networks for each decade. The algorithm for deciding how sources and sinks connect, and when, is shown in simplified form in Figure 14, and described below.

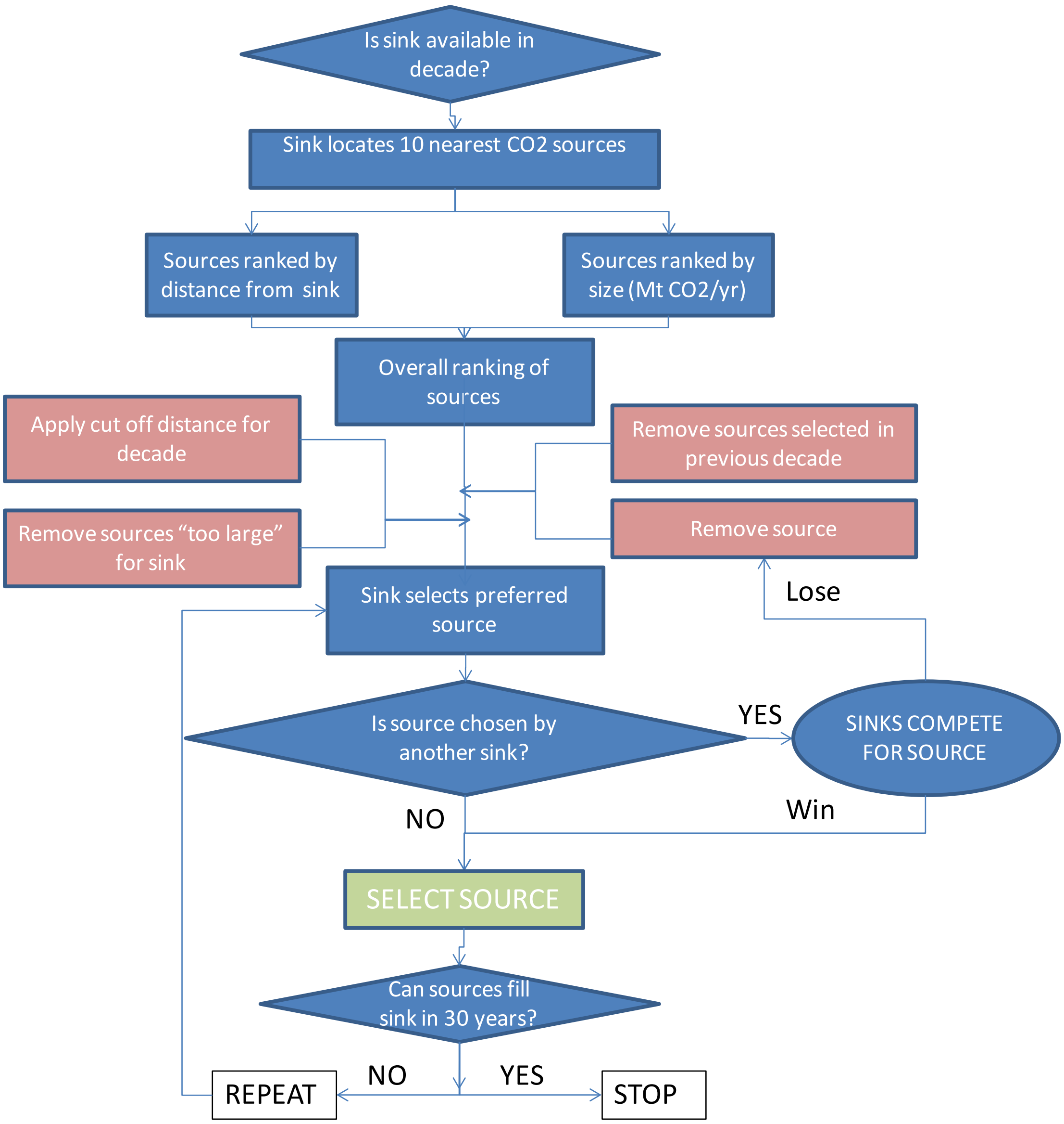
- Sinks were allocated to the decade for which the estimated CoP date indicated availability for injecting CO_2.
- Beginning with 2011-2020, up to three sources are allowed to connect to a sink in any given decade, meaning that by 2050 (end of the 'fourth' decade), a maximum of 12 sources can connect to a given sink.
- Sources can only connect to the sink if the sink is capable of storing their captured emissions for a contracted period, which is 30 years in the baseline. Once a contract has been agreed, the capacity to store this volume of CO_2 is *committed*.
- Sources are weighted for selection by a sink based on their proximity and the magnitude of their capturable CO_2 emissions.
- Once a source connects to a sink, it is not allowed to switch sinks at a later date.
- The upper limit to the distance from sink to source increases between decades as the network develops. The reason for the distance restriction is to prevent sinks connecting to sources that are significant distances away that may connect with other, closer and more economic sinks in subsequent decades. We conducted a sensitivity analysis that removed this restriction and found that it produced a more expensive outcome, see Annex D. The distance in decade:
  - 1, between 2011 and 2020, is up to 250 km;
  - 2, between 2021 and 2030, is up to 500 km;
  - 3 between 2031 and 2040, is up to 1,000 km; and
  - 4 between 2041 and 2050, is up to 1,500 km.
- Where the same sources are selected by different sinks, the competition rules select the closest sink to the source to be connected.

Where there is no competition for sinks, each giant gas field connects to their favoured sources. Where there is a choice of which source connects to a given sink, the ten nearest sources are ranked so that larger and/or nearer sources are chosen, assuming the sink has sufficient capacity. The networks allow multiple sources to connect to a sink through a tree and branch structure. To illustrate how this works, a detailed example is given in Annex C.

The matching of sources with a giant gas field is based on technical and economic factors, and does not take account of political factors nor where CCS is expected to be deployed.

Where more than one source is available to connect to a sink, the cycle is repeated twice, allowing a maximum of three new sources to connect to a sink in each decade.

Figure 14 – Network connection algorithm



Once sources are identified for each sink, the $MtCO_2$ pa transported is calculated, on the basis that 85% of projected emissions are captured. The algorithm is not driven by a particular carbon target, but rather as much CO_2 is stored as is feasible. ***This therefore represents an upper limit***.

The pipeline, platform and well infrastructure are sized according to the average mt CO_2 transported in the decade in which they were built. This was considered to be a reasonable approach given the limited foresight of sources and uncertainty around emissions growth from any individual source. If new connections are possible in subsequent decades, then new infrastructure is constructed. This approach allows projects limited foresight, which is broadly consistent with industry experts' views on historic pipeline growth in the oil and gas industry.

4.6 Global modelling results

Table 15 summarises the global results of the modelling analysis.

Table 15 – Summary of global results

	2011-2020	2021-2030	2031-2040	2041-2050
Giant gas fields available following CoP				
New sinks that become available following CoP	123	121	62	59
Cumulative number of sinks available	123	244	306	365
Additional storage capacity available following CoP (Gt)	55	103	57	45
Cumulative storage capacity available (Gt)	55	158	215	260
Giant gas fields sufficiently close to large CO_2 sources				
Additional sinks connected to sources	60	68	70	35
Cumulative number of sinks connected to sources	60	128	198	233
Additional sources connected to sink	119	162	163	122
Cumulative sources connected to sinks	119	281	444	566
Additional capacity of sinks connected to sources (Gt)	33	56	48	21
Cumulative capacity of sinks connected to sources (Gt)	33	89	137	158
CO_2 transported and stored				
CO_2 transported/year from new projects (Gt)	0.4	0.6	0.6	0.5
Average CO_2 transported/year from all projects (Gt)	0.4	1.0	1.6	1.7
Total CO_2 transported in decade from all projects (Gt)	3.8	10.1	16.4	17.4
Total CO_2 stored by end of decade (Gt)	3.8	13.9	30.3	47.8
No. sinks unable to accept CO_2 from additional sources	9	28	53	80
Remaining capacity in giant gas fields				
Remaining capacity at end of decade (Gt)	51	144	185	209
Remaining uncommitted capacity (Gt)	43	128	166	196
Remaining uncommitted capacity close to sources (Gt)	22	59	88	94

Source: www.co2captureandstorage.info and Giant Fields Atlas

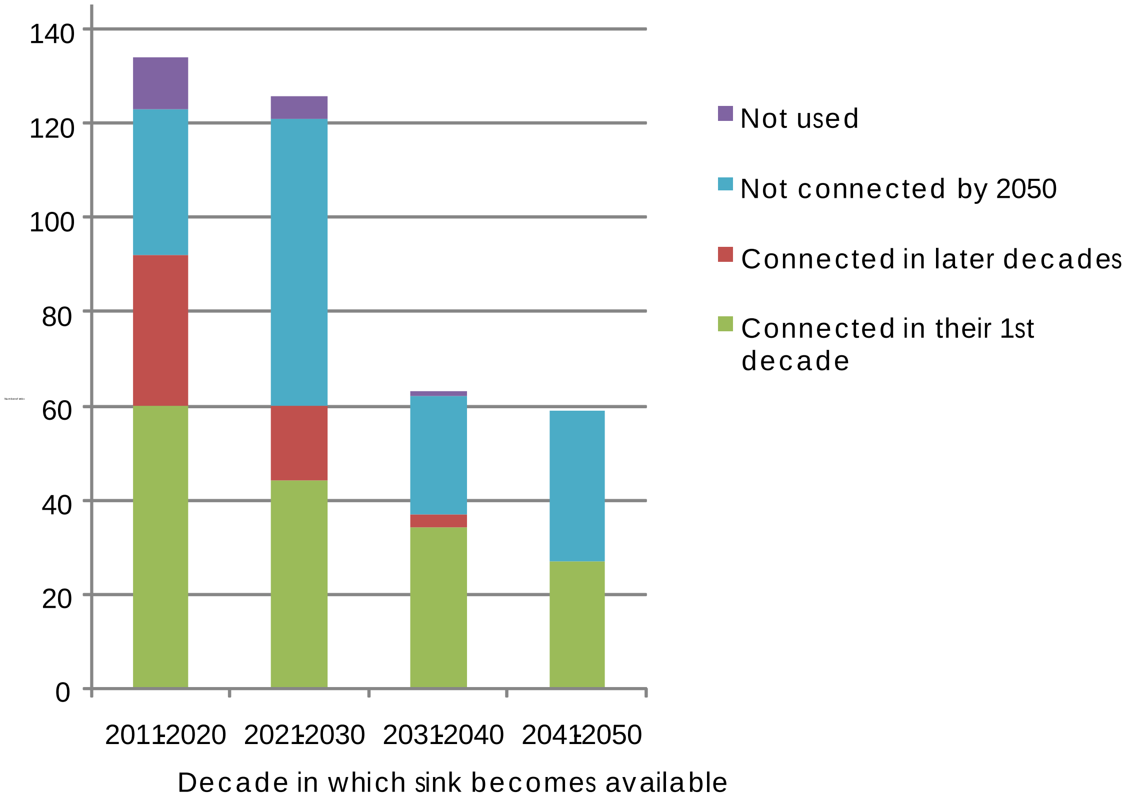
The key points from Table 15 are summarised below:

- At the end of the period being studied, 566 large stationary sources connect to 233 giant gas fields to which 1.7 Gt of CO_2 is transported and stored each year. This volume of CO_2 is 8% of average annual emissions from large stationary sources.
- By 2050 sufficient capacity to store 260 Gt of CO_2 has become available, of which only 158 Gt is sufficiently close to sources to connect to them.
- 132 giant gas fields, with 104 Gt of capacity, do not connect to sources, due to them being too remote or situated in a cluster of sinks which have connected to a source.
- Globally CCS involving depleted giant gas fields has the potential to transport and store approximately 48Gt of CO_2 by 2050.
- By 2050 80 giant gas fields have sufficient connections to sources that they are not able to accept CO_2 from additional sources.
- While there is 209 Gt of storage capacity available from 2050, 104 Gt is too remote for it to connect to a source and 92 Gt is within gas fields that have connected to a source but not contracted to accept additional CO_2. Much of the 92 Gt of capacity will be in regions where there are more sinks than sources, such as the Middle East.

Figure 15 below show the number of giant gas fields that become available for CO_2 storage in each decade being considered and subdivides them according to how they are treated in the network model. It shows that of the 134 that become available in decade 1:

- 60 connect to sources in decade 1;
- 32 connect to sources in a later decade;
- 31 do not connect to any source by 2050; and
- 11 are not suitable for storing CO_2.

Figure 15 – Sinks connecting to network by decade sink becomes available



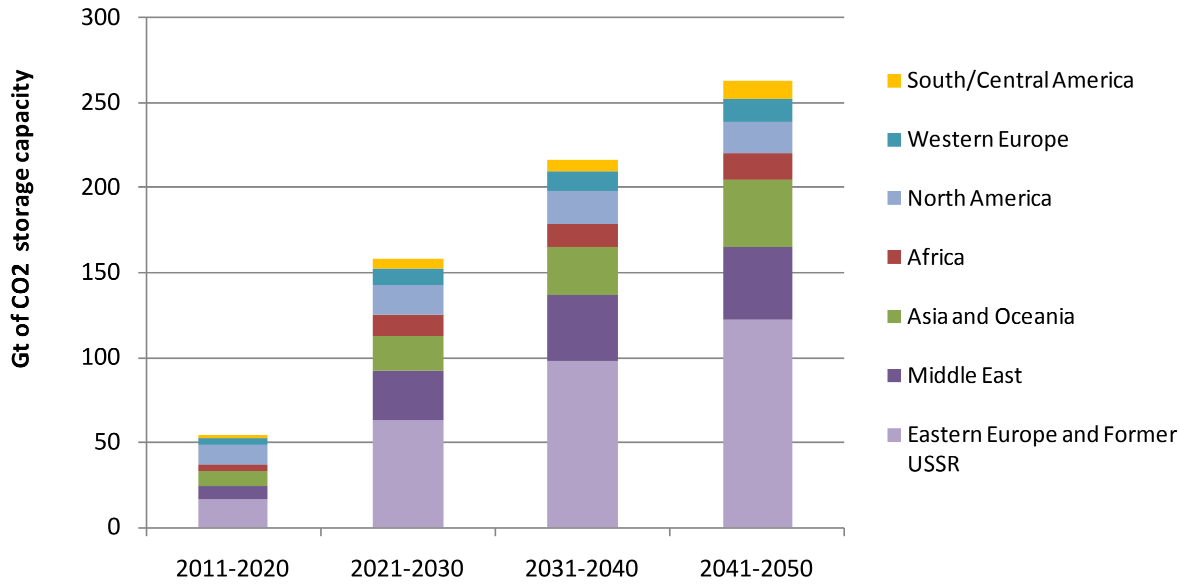
Source: www.co2captureandstorage.info and Giant Fields Atlas

The key reason why some of the available gas fields do not connect to sources until a later decade is because of the distance restriction discussed above.

4.7 Regional modelling results

This section discusses how matched storage capacity evolves in each region. Figure 16 below indicates the volume of capacity expected to be available by decade and region.

Figure 16 – Cumulative CO_2 capacity in giant gas fields by region 2011 to 2050



Source: Giant Fields Atlas

The majority of potential storage capacity is concentrated in Eastern Europe and the Former Soviet Union, principally in Siberia.

Below are a series of maps that illustrate the sources, sinks and CO_2 pipeline networks generated, for each continental region, using the network connection algorithm. As this study is a global analysis, it was necessary to design an algorithm, meaning that the resulting networks may differ substantially from networks actually constructed. The regional groupings in the following maps not entirely correspond to the regional groupings presented elsewhere.

The giant gas fields are shown as stars sized according to capacity, and colour coded according to the decade when they first become available. Sources are shown as green circles, sized by emissions by diameter. Pipeline networks are shown as lines that are colour coded according to when they are installed. Dotted lines indicate long offshore distances where additional shoreline boosting to above 250 bar is required.

All pipelines are displayed as straight lines, however, to allow for actual deviation, costs were based on straight line distances multiplied by 1.25. All boosting occurs onshore, and boosters are placed wherever:

- a pipeline crosses the coastline;
- pipelines connect to each other onshore; and
- the pressure in onshore pipelines drops to the minimum threshold of 85 bar and requires boosting.

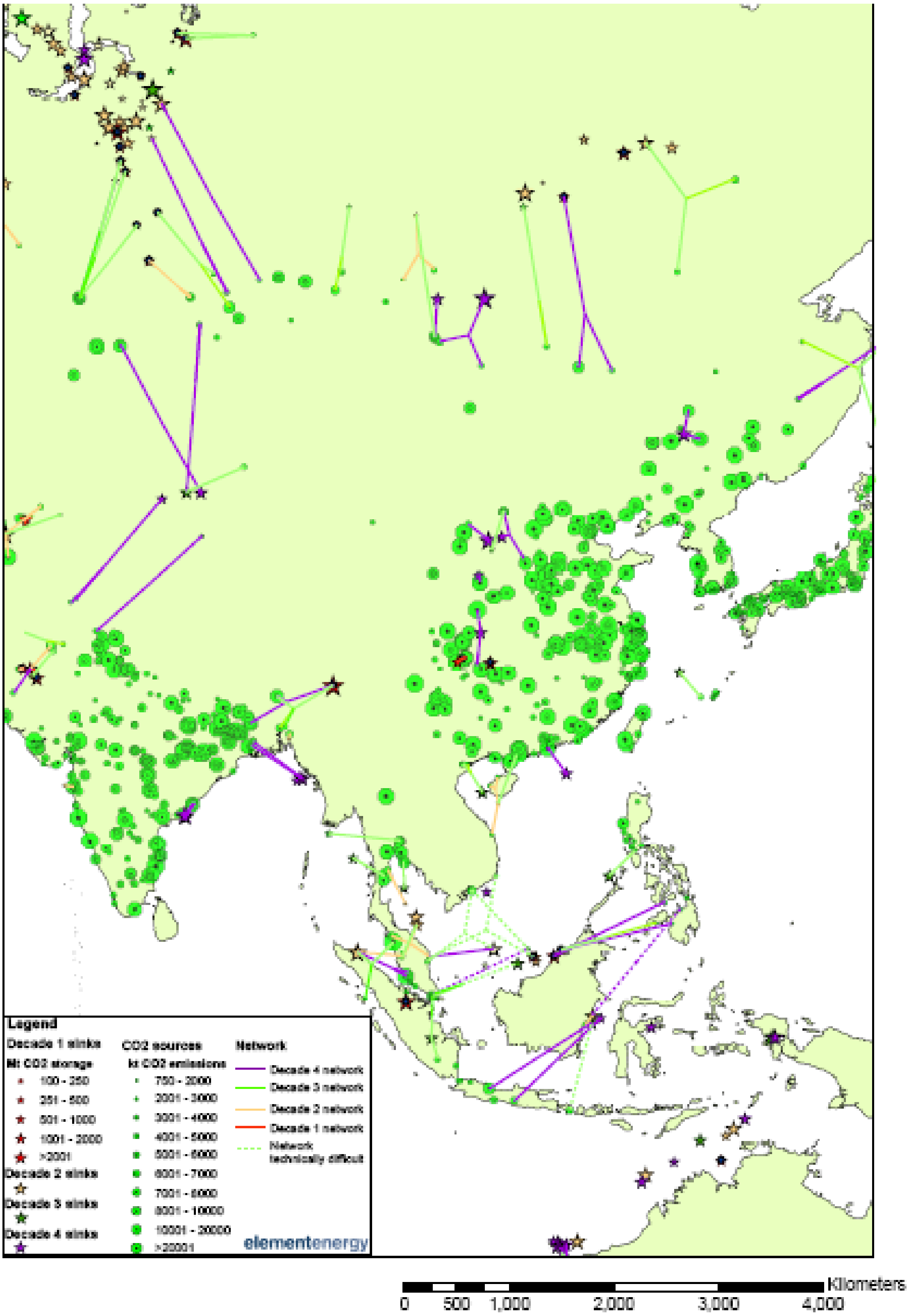
A sensitivity analysis of the assumptions is provided in Annex D.

4.7.1 Asia and southern Russia

Figure 17 details the network linking large stationary CO_2 sources with giant gas fields in Asia. The key points are listed below.

- There significant clusters of large sources in China, India and Japan that never connect to giant gas fields.
- Central Asia contains few giant gas fields, far apart from other fields or in small clusters. These typically have late CoPs, estimated to be after 2030, from when they are matched to large local point sources.
- A large number of the sources in Indonesia Malaysia, the Philippines and Thailand connect to giant gas fields, but several of these involve long offshore pipelines, which involve higher costs.
- There are remote large clusters of giant gas fields with few nearby stationary sources in Siberia around the Kara Sea. The latter region sees some projects with long, 500km, pipelines but is dominated by excess storage capacity.

Figure 17 – Network linking CO_2 sources with giant gas field in Asia and southern Russia



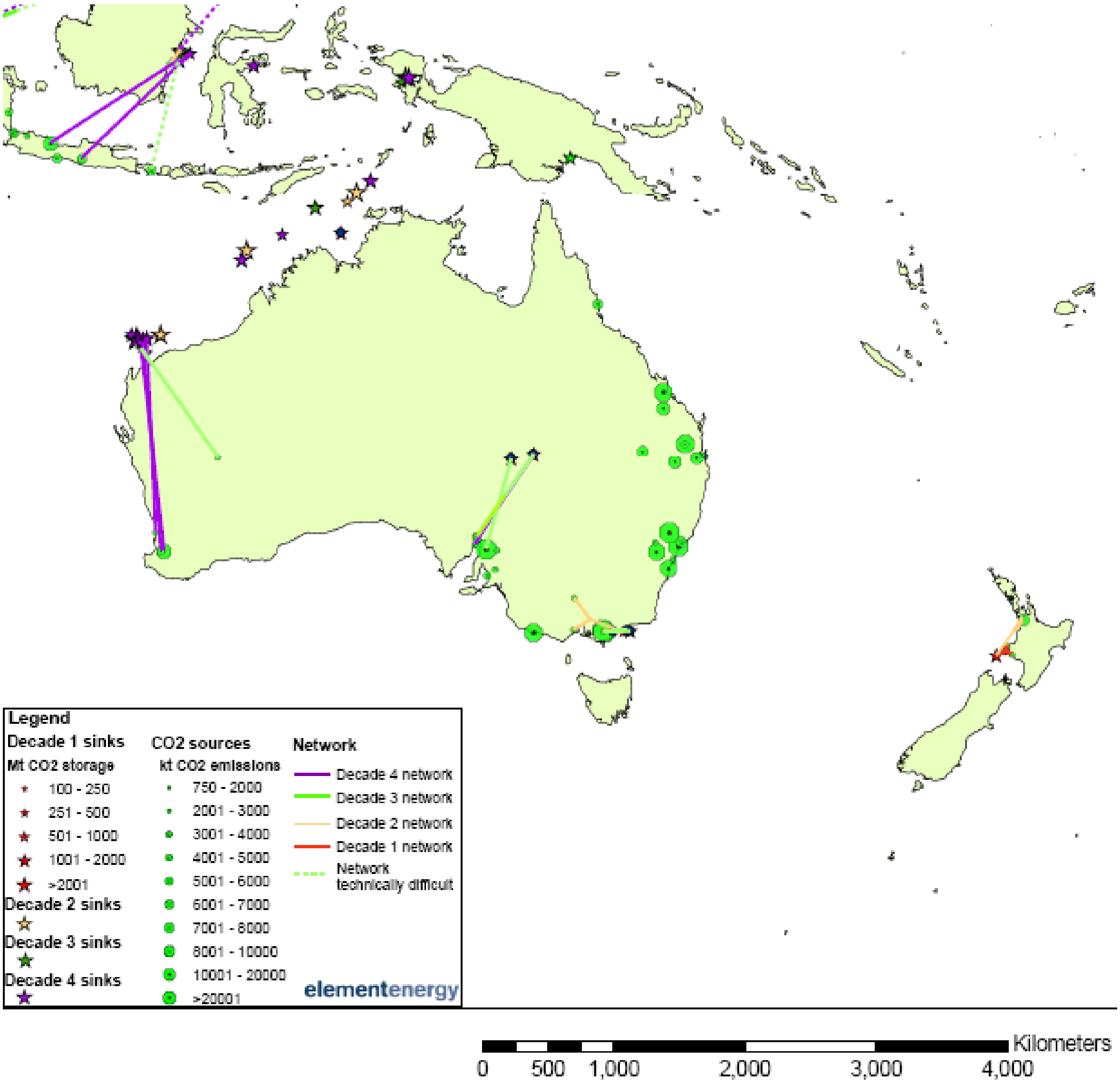
Source: www.co2captureandstorage.info and Giant Fields Atlas

4.7.2 Oceania

Figure 18 details the network linking large stationary CO_2 sources with giant gas fields in Oceania. The key points are listed below.

- Sources around the eastern seaboard, particularly near Sydney and Brisbane do not have good access to giant gas fields.
- Sources in South Australia and Melbourne have access to giant gas fields in central Australia (Moomba) and Bass Straight respectively.
- Western Australia has access to giant gas fields on the North West Shelf (Gorgon).
- There are a large number of giant gas fields between North Western Australia, and Indonesia that do not connect to any sources.
- There is a giant gas field close to New Zealand that can be used to store CO_2.

Figure 18 – Network linking CO_2 sources with giant gas field in Oceania



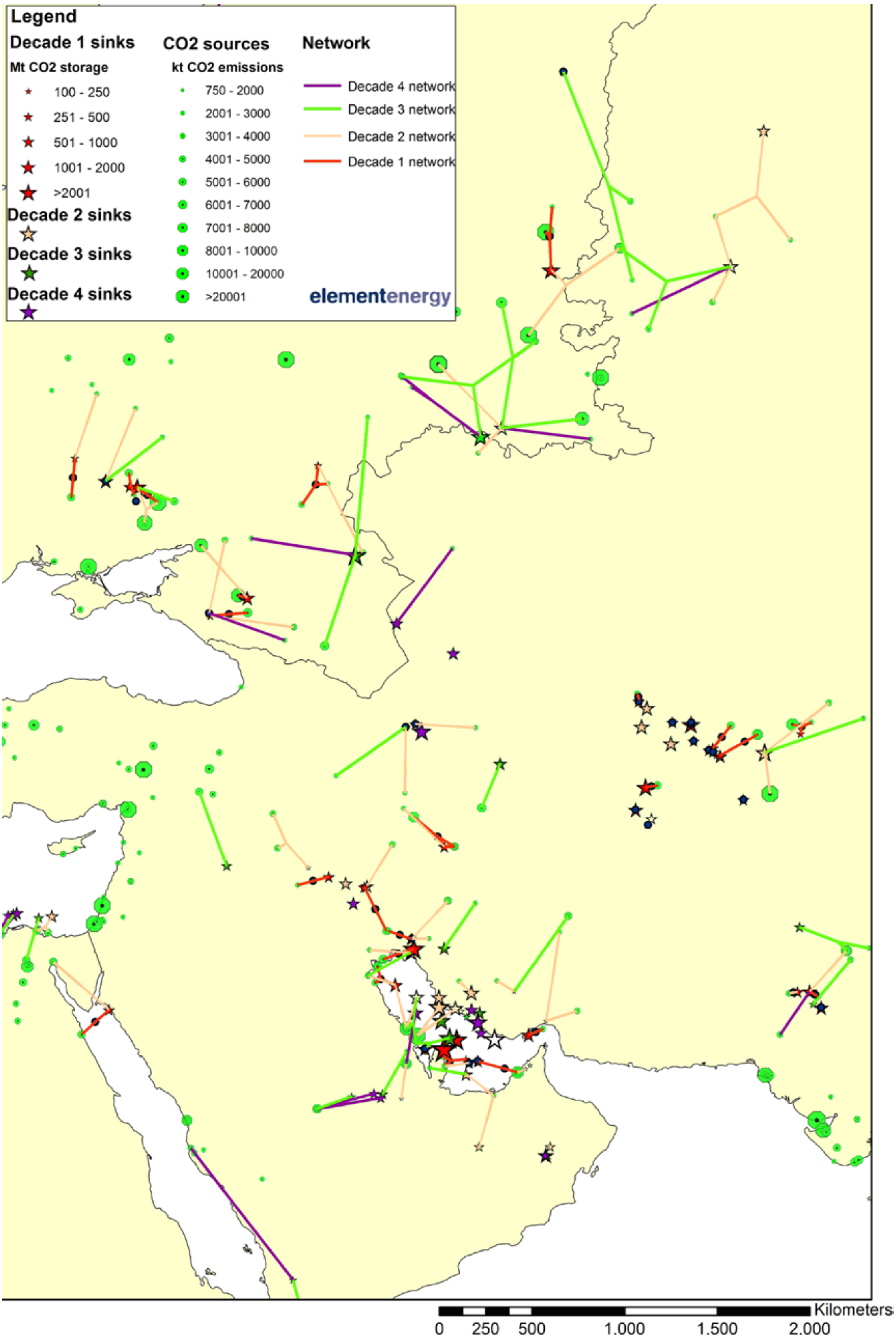
Source: www.co2captureandstorage.info and Giant Fields Atlas

4.7.3 The Middle East and Former Soviet Union

Figure 19 details the network linking large stationary CO_2 sources with giant gas fields in the Middle East and parts of the Former Soviet Union. The key points are listed below.

- The Persian Gulf has multiple large sinks and a significant number of large sources in close proximity.
- Late CoP dates and the high number of sinks, with respect to sources, in the Persian Gulf ensure sinks are not fully utilized.
- There are a large number of giant gas fields in the Former Soviet Union, but these are located at significant distances from the CO_2 sources.
- There are efficiently matched areas in Southern Russia between sources and giant gas fields, with virtually all CO_2 sources connected to sinks, and few or no unused giant gas fields.

Figure 19 – Network linking CO_2 sources with giant gas field in Middle East and Former Soviet Union



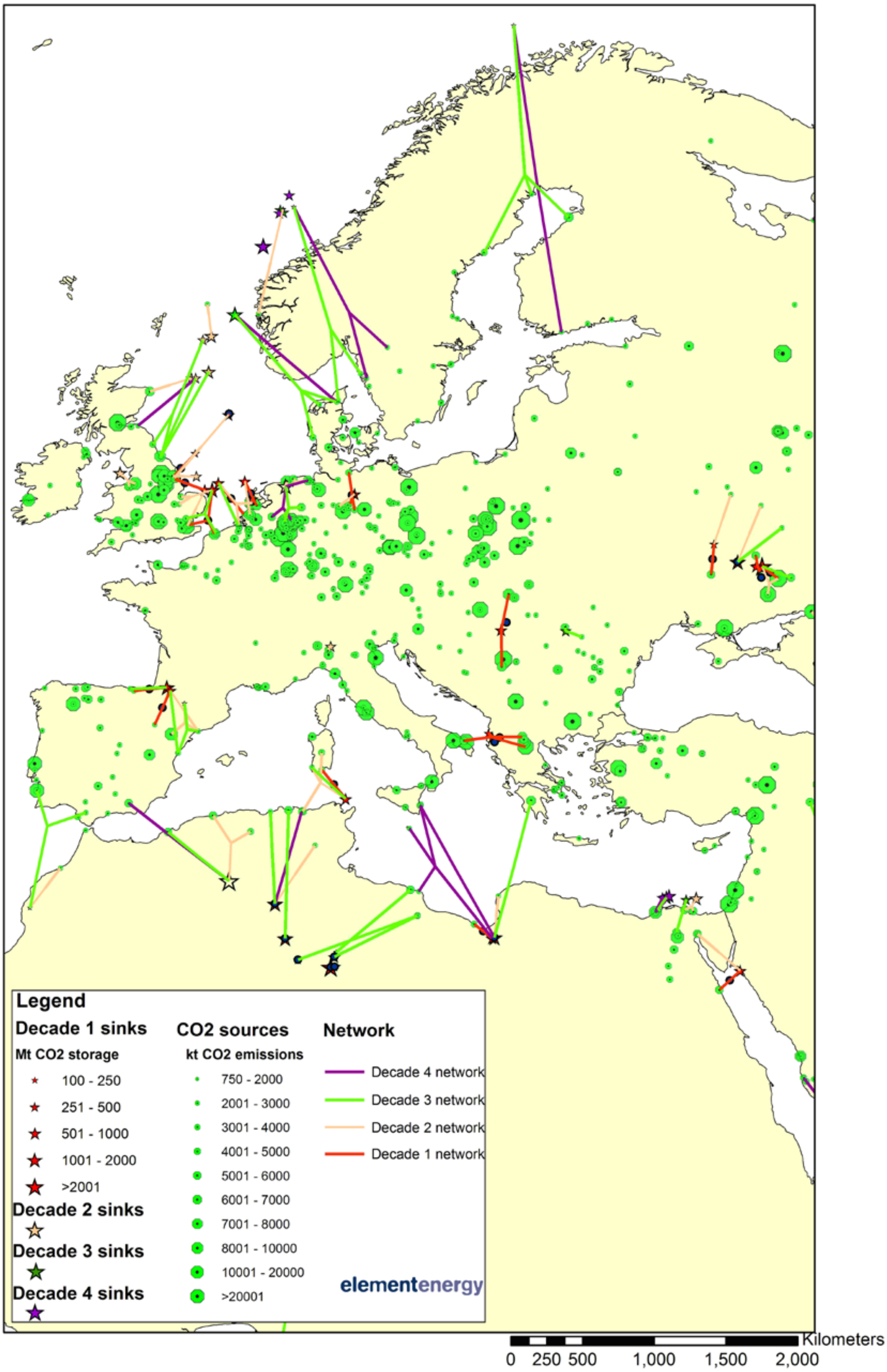
Source: www.co2captureandstorage.info and Giant Fields Atlas

4.7.4 Europe and Northern Africa

Figure 20 details the network linking large stationary CO_2 sources with giant gas fields in Europe and Northern Africa. The key points are listed below.

- There are a large number of giant gas fields in the North Sea and some onshore, which connect to large CO_2 sources.
- There are a significant number of CO_2 sources that are not able to connect to giant gas fields.
- There is significant capacity in Northern Africa, but it is remote from most of the sources.

Figure 20 – Network linking CO_2 sources with giant gas field in Europe and Northern Africa



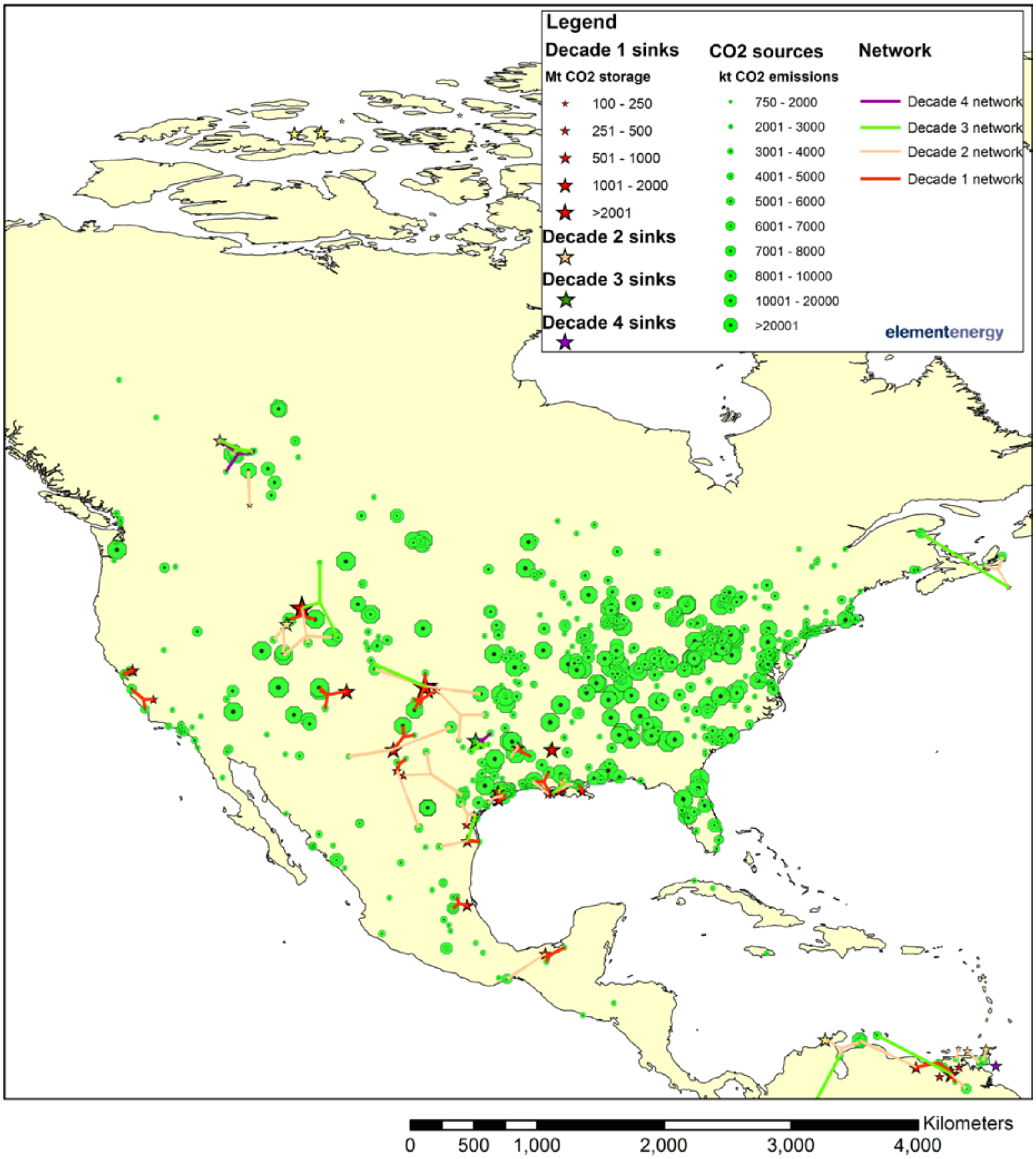
Source: www.co2captureandstorage.info and Giant Fields Atlas

4.7.5 North America

Figure 21 details the network linking large stationary CO_2 sources with giant gas fields in North American. The key points are listed below.

- There significant clusters of large sources in Eastern USA that do not have access to giant gas fields.
- There is better matching between sources and giant gas fields in the central US and in pockets around the Gulf of Mexico, with sinks primarily being onshore, relatively close to sources, and having early close of production dates.
- As many of the giant gas fields have early CoP dates, are close to CO_2 sources and are onshore, the modelling indicates that the percentage of capacity in North American giant gas fields that stores CO_2 will be the highest of all regions.
- There is some capacity in isolated sinks in the far North of Canada, which is greater than 1,500km away from any large stationary sources.

Figure 21 – Network linking CO_2 sources with giant gas field in North America



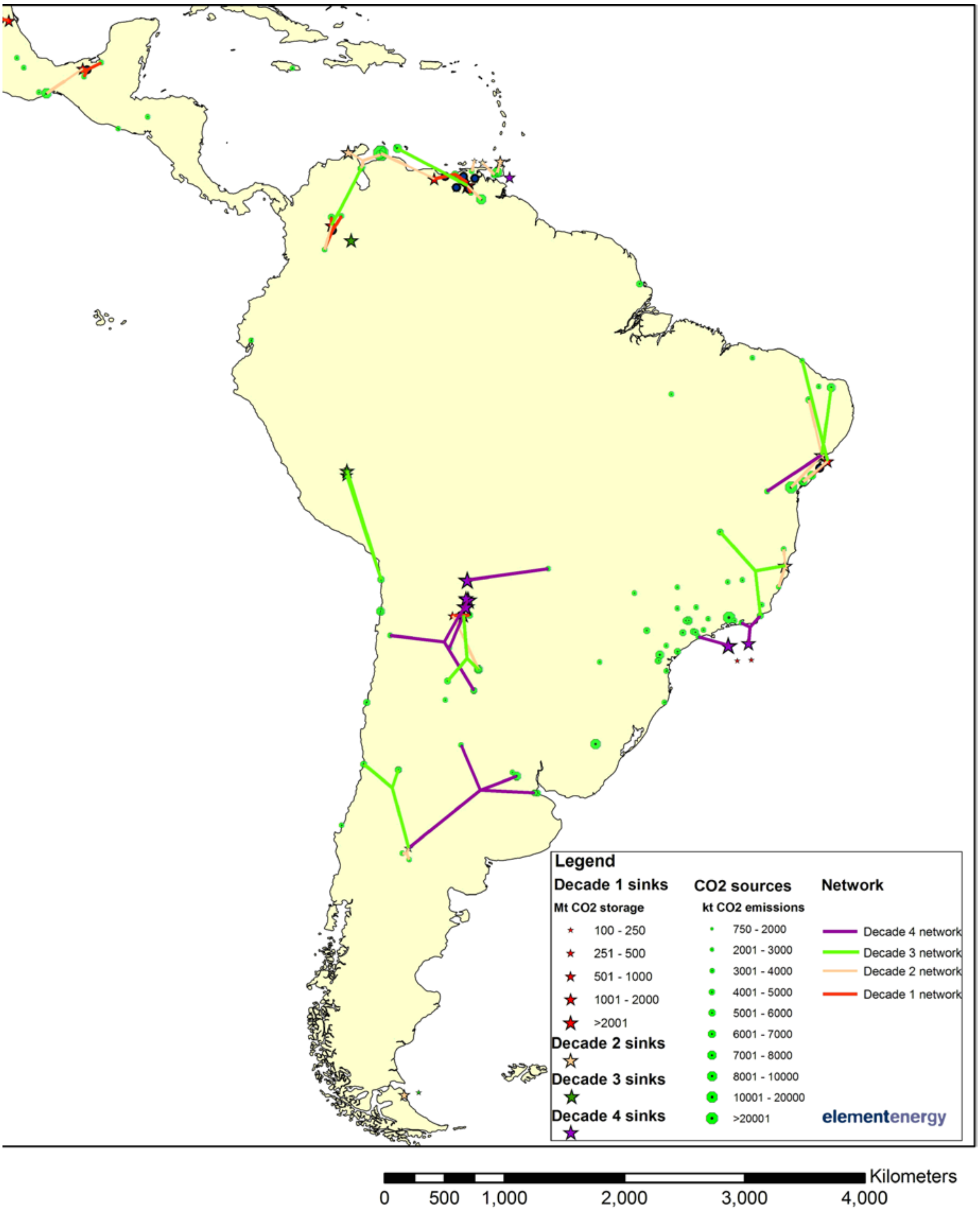
Source: www.co2captureandstorage.info and Giant Fields Atlas

4.7.6 South America

Figure 22 details the network linking large stationary CO_2 sources with giant gas fields in Central and South America. The key points are listed below.

- There are few large sources, compared to North America, Europe and Asia, and they can be well matched with giant gas fields.
- The linking between sources and sinks will involve relatively long pipelines and, as the CO_2 emissions are relatively low, they are unlikely to attain higher economies of scale and hence face higher unit costs.

Figure 22 – Network linking CO_2 sources with giant gas field in South America



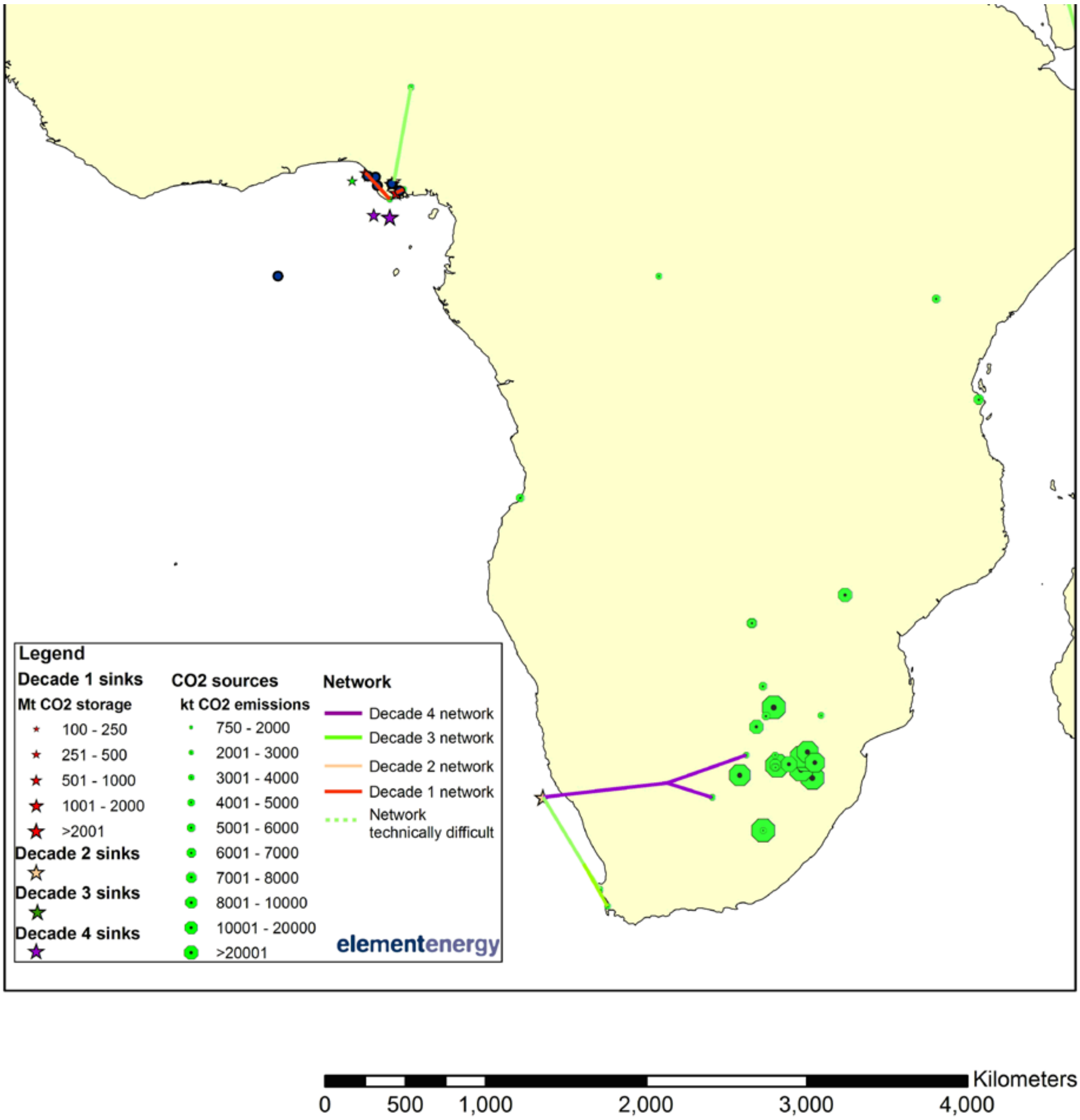
Source: www.co2captureandstorage.info and Giant Fields Atlas

4.7.7 Southern and Central Africa

Figure 23 details the network linking large stationary CO_2 sources with giant gas fields in Southern and Central Africa. The key points are listed below.

- There are few large sources, with those that do exist being located in eastern South Africa, near Johannesburg.
- There are few giant gas fields available, presenting few options to store CO_2.

Figure 23 – Network linking CO_2 sources with giant gas field in Southern and Central Africa



Source: www.co2captureandstorage.info and Giant Fields Atlas

4.7.8 Assessment of regional analysis

The key points from the above analysis are summarised below.

- The majority of giant gas fields, and the majority of CO_2 storage capacities, occur in clusters comprising several giant gas fields, e.g. the Persian Gulf, the Kara Sea near Siberia.
- Sources are also unequally distributed. The majority of CO_2 sources are clustered in China, Eastern USA, Europe, India and Japan.
- Matching of sources and sinks is highly variable. Some regions are well matched for example in the Persian Gulf, see Figure 19 above, defined as having multiple large sources and sinks in close proximity.
- Some regions have a very large number of sources e.g. India, with very few giant gas fields. In these regions, the technical suitability and availability of oilfields and saline aquifers, ship transport or the use of very long pipelines will be critical for widespread deployment of CCS.
- Some areas, such as those in Eastern Europe, appear efficiently matched between sources and giant gas fields, with virtually all CO_2 sources connected to sinks, and few or no unused giant gas fields.
- Realistically, capture, transport or storage will not always be technically or economically suitable at every site. Therefore CCS uptake in these areas will be highly sensitive to the local technical suitability and market environment for capture, transport and storage. Some areas do offer significant storage potential, but are restricted by the need for long pipelines, e.g. Siberia, and by small sources in places such as South America.

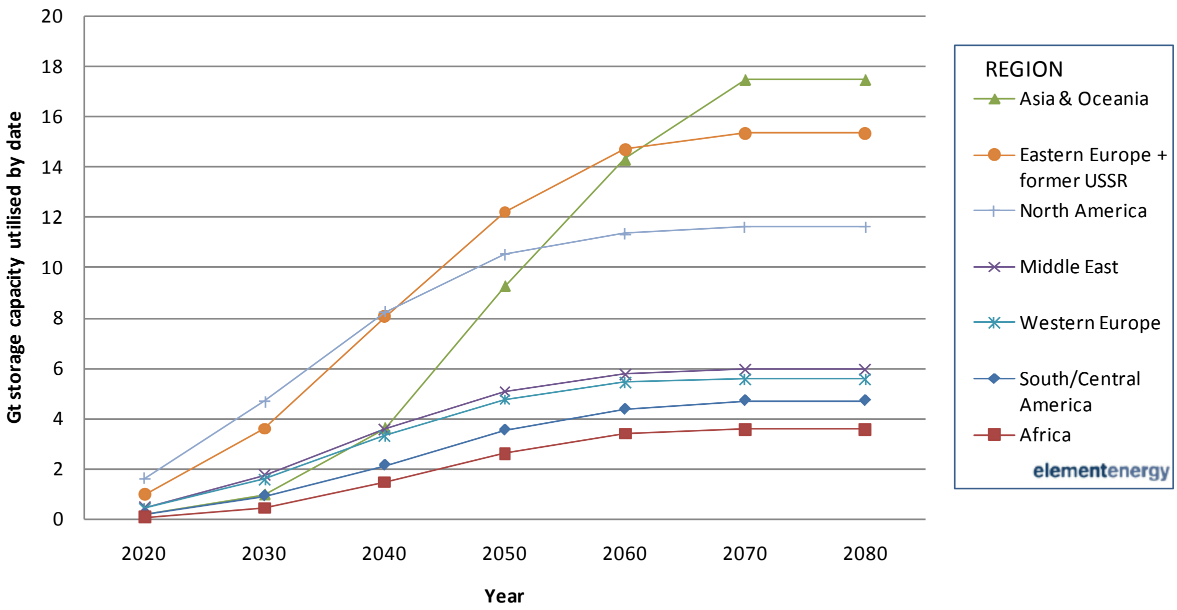
It should be noted that as this work is a global study, it was necessary to make some generalising assumptions, and so it does not replace the need for regional studies into network design and optimisation.

4.8 The storage of CO_2 in depleted gas fields over time

This section presents the modelling outputs for the volumes of CO_2 stored over time by region before drawing some conclusions.

The modelling indicates that by 2050 contracts will have been entered into to store approximately 60 Gt CO_2 in depleted giant gas fields. This is represented in Figure 24 overleaf shows the cumulative CO_2 stored in depleted giant gas fields up until 2080 for contracts to store CO_2 entered into prior to 2050. We anticipate that new contracts will be entered into after 2050, but this has not been included in this analysis.

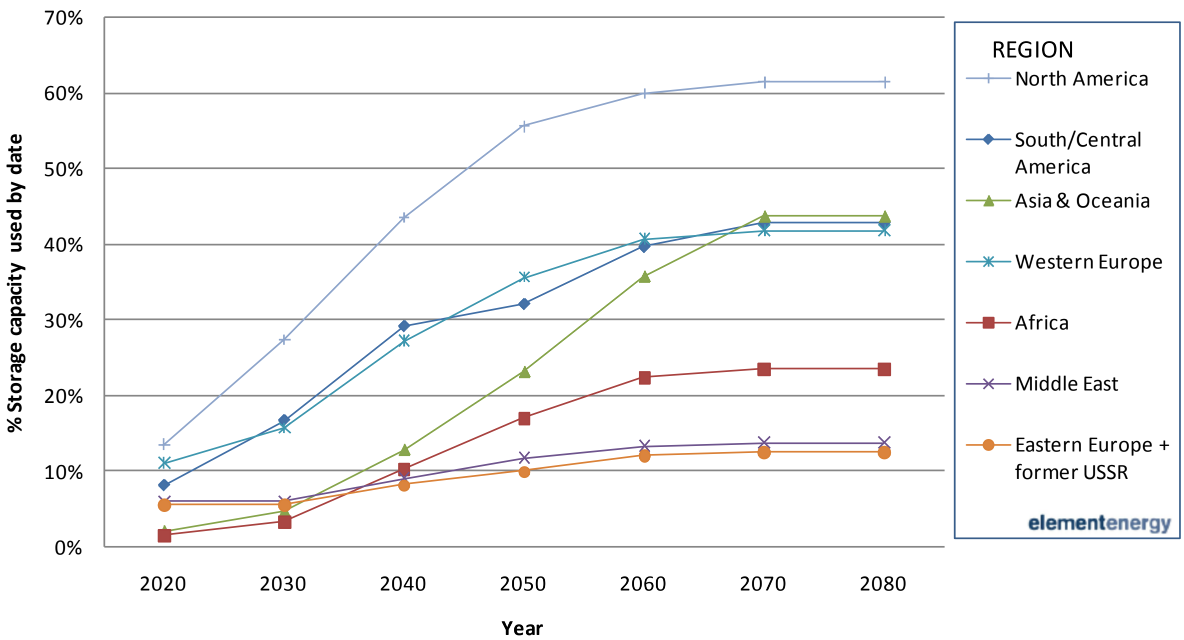
Figure 24 – Cumulative volume of CO_2 stored in giant gas fields by region



Source: Giant Fields Atlas

Figure 25 below shows volume of CO_2 stored under contracts entered into by 2050 as a percentage of the total capacity in giant gas fields for each region.

Figure 25 – Cumulative percentage of capacity in giant gas fields used over time



Source: Giant Fields Atlas

To put the potential for CO_2 transport and storage identified in this analysis into context, we have calculated the capacity of coal and gas-fired power stations that would produce the level of emissions that we estimated could be stored in giant gas fields by 2050 for each region. These results can be seen in Table 16 below.

Table 16 – Estimate of capacity to produce peak annual volume of CO_2 stored

	Peak CO_2 transport (mt.p.a.)	TWh equivalent coal	TWh equivalent gas	GW capacity of equivalent standard coal power stations	GW capacity of equivalent gas power stations
South/Central America	139	160	420	20	60
Africa	112	130	340	20	50
Asia and Oceania	565	660	1,710	90	240
Middle East	152	180	460	30	70
Western Europe	144	170	440	20	60
Eastern Europe and Former USSR	418	490	1,270	70	180
North America	227	270	690	40	100
Total	***1,757***	***2,060***	***5,330***	***290***	***760***

Assumes: Load factor 80%, 850g/kWh intensity for coal power stations and 330g/kWh intensity for gas power stations

The key points from the above are listed below.

- we have estimated that Asia/Oceania and Eastern Europe plus the Former Soviet Union are capable of storing 18 Gt and 15 Gt of CO_2 respectively from projects commissioned before 2050, making them the regions with the largest potential for storing CO_2 in depleted gas fields.
- The CoP for gas fields in the Asia and Oceania region are predominantly late, meaning the bulk of the storage potential in depleted gas fields will not be available until the end of the study period.
- The gas fields in North America typically have early CoP dates, are onshore and close to CO_2 sources, suggesting that they may be used to store CO_2 earlier than gas fields in other regions.
- Europe and the Middle East have smaller but still significant technical storage potential, both with approximately 6 Gt of CO_2 stored by the close of projects. In the Middle East this represents a low percentage of the total storage available (11%).

4.9 Costing CCS Networks

This section presents the findings of the costing analysis of the transport and storage infrastructure for all connecting giant gas fields in the study. The overall cost of transporting and storing CO_2 for each network was assessed by calculating the relevant lifetime capital and operating expenditures for pipelines, boosters, drilling, injection facilities and storage for each project. Operational costs are discounted back to the year of start for the project as part of a project net present value calculation.

For a given field, the costs for projects beginning in separate decades are combined to give an overall NPV cost for the sink. This number is then divided by the total CO_2 transported over the lifetime of all projects to give a total overall NPV cost per tonne for CO_2 transport and storage for a given sink.

The methodology for calculating these costs is described in more detail in Section 3.

Table 17 – Structure of costing analysis

Component	Costs included	Key parameters
Pipelines	Capital expenditure	The flow rate, diameter, onshore and offshore lengths.
	Discounted operational expenditure	2% of capex each year over 30 years
Boosters	Capital expenditure	The boosters required along pipeline based on pressure drop.
	Discounted operational expenditure	Maintenance, assumed to be 4% of capex each year over 30 years, and electricity costs
Facilities	Capital expenditure	Whether on- or offshore, water depth, number of injection wells, and whether boosting is required.
Wells	Drilling costs	The number of wells required for the given CO_2 flow for a given field. Water and reservoir depth.
	Injection	Type and number of injection facilities required based on the field location and number of wells required.
Monitoring	Annual cost based on CO_2 throughput	\$0.30/t CO_2 stored for 50 years from start of project

The discount rate in the base case is 10% and a sensitivity analysis was run with 0% discount rate. The period in the base case is 30 years for the transport and storage facilities and 50 for monitoring from the start of the project.

The costing analysis in this study does NOT include:

- the cost of capture, purification and initial compression, as CO_2 is assumed to enter the network at the required purity and at 150 bar pressure;
- the cost of commercially financing up-front capital expenditure;
- cost of remediating existing wells;
- contingency; and
- owners costs.

The costs reported are per tonne of CO_2 transported rather than CO_2 abated. CO_2 emitted during construction or operation of the network is not taken into account.

4.9.1 Global cost results

The modelling process connected a total of 566 sources to 233 giant gas fields, but there was only sufficient information available to determine the costs for transport to and storage at 222 of the sinks. The costing analysis is based on the costs associated with transported and storing the CO_2 the 222 gas fields are committed to store, which is 60 Gt CO_2. The NPV costs per lifetime tonne of CO_2 stored in these giant gas fields, reported in US\$ 2008 currency, have been ranks and are presented in Figure 26 overleaf.

Figure 26 – Marginal abatement curve for transport and storage

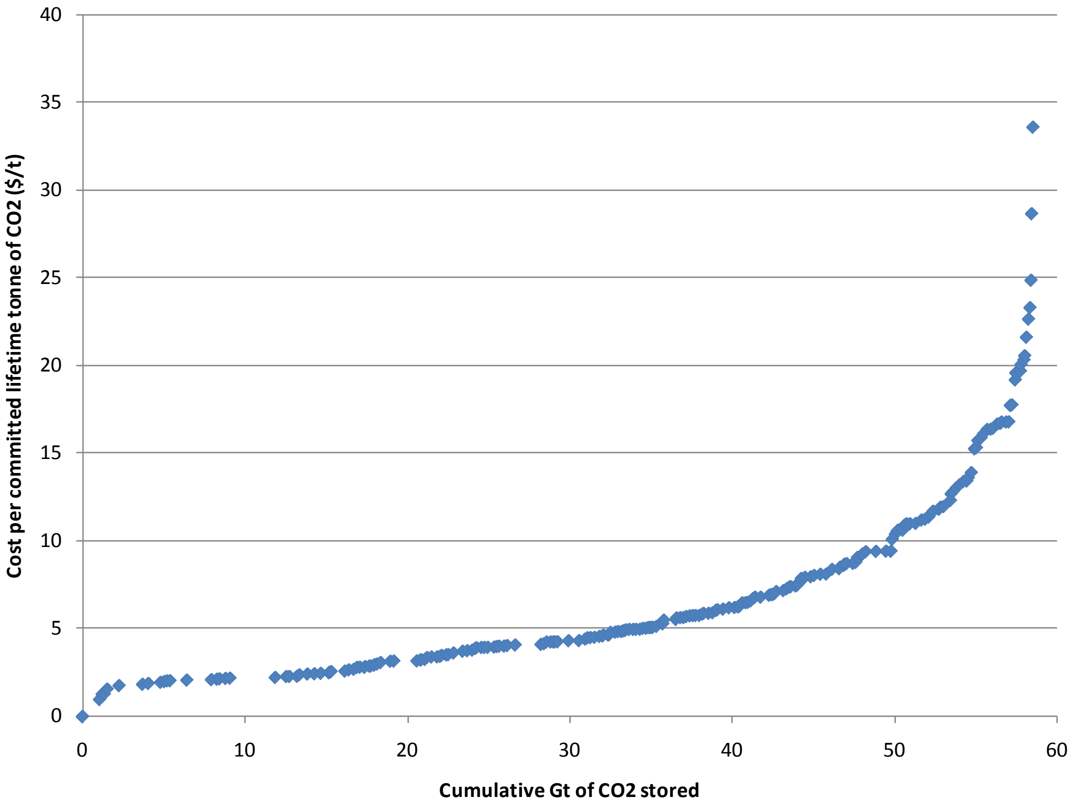


Figure 26 above indicates that:

- 30 Gt of CO_2 storage capacity is available at costs below $5 per lifetime tonne for transport and storage.
- 50 Gt of CO_2 storage capacity is available at costs less than $10 per lifetime tonne for transport and storage; and
- beyond 50 Gt of CO_2 storage capacity, the marginal cost curve increases exponentially.

For storage in giant depleted gas fields connected to large sources, the costs for transport and storage are significantly lower than the majority of published capture costs, which are typically estimated at least $30/t CO_2.

Figure 27 overleaf splits the total cost for transport to and storage in a giant gas field, into components.

Figure 27 – Breakdown of total costs

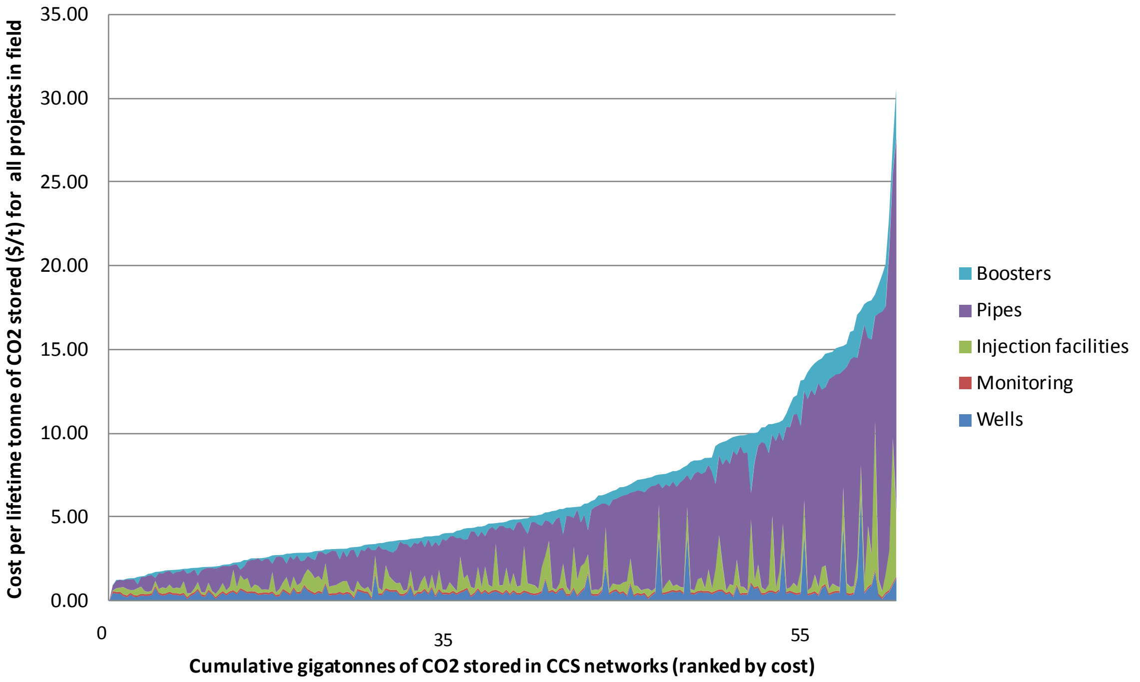


Figure 27 above indicates that pipeline costs dominated total transport and storage costs. CCS unit costs are low when large sources connect to nearby onshore shallow sinks, while costs escalate when a few small sources connect and/or the distances are long.

The spikes in the injection facilities and well costs, seen along the bottom of Figure 27, are cases where the giant gas field is located offshore. The impact of the sink being located on or offshore and the water depth for offshore sinks on cost is shown in Table 18 below. Approximately half of the sinks that are onshore or in shallow water incur costs less than $5/tCO_2$, while as the water depth increases the profile changes so that an increasing percentage of sinks incur costs greater than $5/tCO_2$.

Table 18 – Distribution of giant gas fields by water depth and corresponding cost

Cost ($2008) per lifetime tonne of CO_2 stored	Onshore	Water Depth 0-100m	100-200m	200-1000m	1000m+	Total
<$ 5 /t CO_2	72	21	4	2	-	99
$ 5-10 /t CO_2	46	12	6	3	2	69
$ 10-20 /t CO_2	25	8	3	5	4	45
$ 20-30 /t CO_2	3	3	-	2	-	8
$ 30-40 /t CO_2	-	-	-	1	-	1
Grand Total	**146**	**44**	**13**	**13**	**6**	**222**

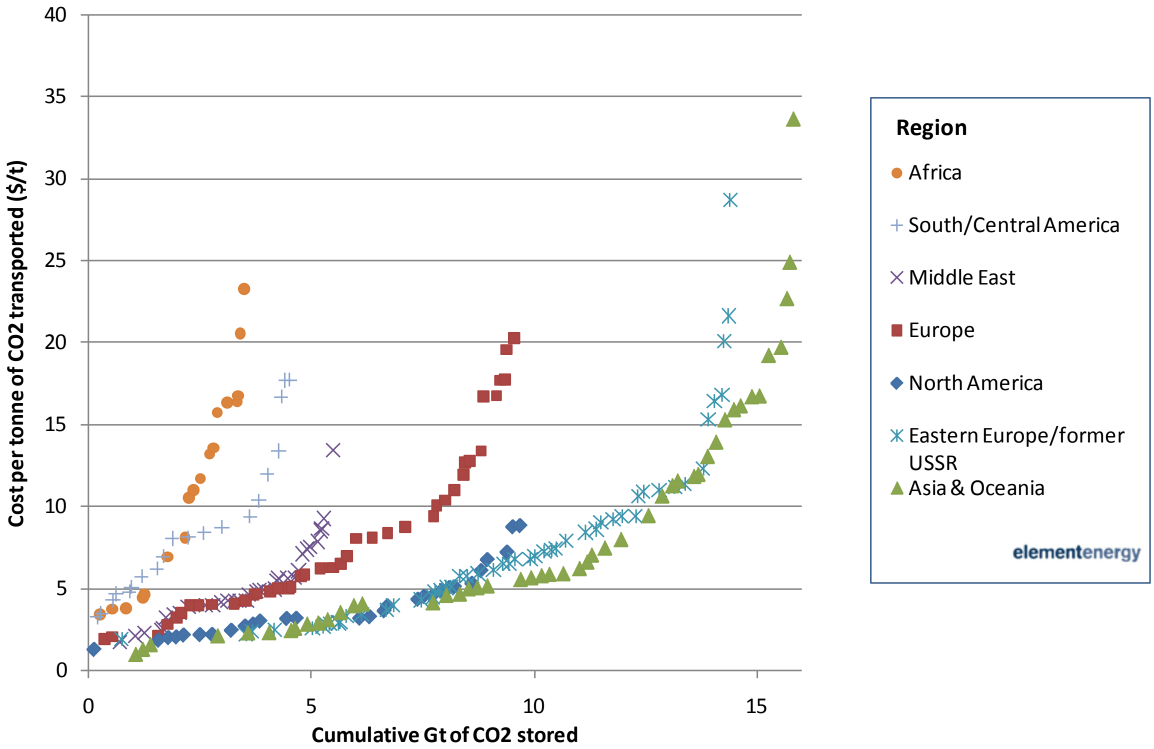
Table 18 also indicates that 85% of sinks are either onshore or in shallow water, helping explain why half of the CO_2 storage capacity is available for less than $5/t$CO_2$, as indicated in Figure 26 above.

4.9.2 Regional cost results

Figure 28 overleaf shows the marginal abatement cost curves for different regions. The general shapes of the curves are similar, however the graph highlights the significant differences in the variation of transport and costs between regions with capacity.

- All continental regions have some CCS opportunities with transport and storage costs for CCS below $5/t CO_2.
- North America has relatively inexpensive opportunities for giant gas fields connected to large stationary sources across the range. This is due to a combination of short pipelines, and onshore or shallow water depth gas fields. Some Canadian giant gas fields do not connect to sources by 2050, as they are greater than 1,500km away from any large stationary sources.
- In Europe the majority of giant gas fields are offshore, and therefore on average further away from sources and more expensive in terms of drilling and facility costs. The lower cost sinks represent a few onshore opportunities and sinks located in shallow water in the Southern North Sea. The more expensive sinks are in deeper waters and more remote sinks in the Northern North Sea and Norway.
- Asia has large CCS opportunities at relatively low costs, provided that economies of scale can be achieved by connecting multiple large sources to large sinks. These prospects are highly spread geographically with low cost sinks located around Thailand, and in parts of China and Indonesia.
- Costs for storage in giant gas fields in Western Australia represent the higher end of the cost curve for Asia and Oceania.
- In the Middle East, there are significant opportunities for CCS at costs below $5 per lifetime tonne of CO_2 transported in the Persian Gulf.
- Eastern Europe and the Former Soviet Union have approximately 12 Gt of storage capacity accessible for less than $10 per lifetime. Remote sinks in Siberia lacking in significant CO_2 sources within 1,500km are not connected to sources by 2050 in the model and therefore not included in this cost curve.
- Africa's giant gas fields are in general remote from major CO_2 sources. Storage is concentrated in Northern Africa, Nigeria and Southern Africa. Small sources and long pipelines, sometimes crossing the Mediterranean, lead to high transport costs.
- The costs of transport and storage in South and Central America are also relatively high and rise steeply with capacity. This is largely because sources and sinks are small and isolated, limiting economies of scale.

Figure 28 – Marginal abatement curves for each region



The key findings of this analysis are:

- All continental regions have some CCS opportunities with transport and storage costs for CCS below $5/t CO_2.
- North America, Asia and Oceania, and Eastern Europe each have approximately 8 Gt CO_2 storage capacity available at less than $5/t CO_2 and represent low cost, high volume regions.
- Europe and the Middle East represent median scenarios in terms of cost and Gt of CO_2 stored.
- The costs of transport and storage in Africa and South and Central America are comparatively high and rise steeply with capacity, largely because sources and sinks are small and isolated, which limits any economies of scale. There are few opportunities for costs below $5/t$CO_2$.

It should be noted that as this work is a global study, it was necessary to make some generalising assumptions, and so it does not replace the need for regional studies into network design and optimisation.

5. ADDITIONAL FACTORS INFLUENCING CO_2 STORAGE IN DEPLETED GAS FIELDS

This study considered the impact the following two issues would have on the development of the use of depleted gas fields to store CO_2:

- the treatment of CO_2 in gas fields with high concentrations of CO_2; and
- the use of CO_2 for enhanced gas recovery (EGR).

The conclusion was that neither issue is likely to have a material impact on the uptake of storing CO_2 in depleted gas fields.

5.1 CO_2 separated from gas fields with high CO_2 concentrations

Gas reservoirs often contain a proportion of naturally occurring CO_2, ranging from a few percent up to 70% by volume. An example of a gas field with a very high concentration of CO_2 is giant Natuna gas field offshore Indonesia.

When gas fields with significant concentrations of CO_2 are being developed, the CO_2 must be separated from the natural gas so that it complies with the technical standards necessary to provide the natural gas to market. Subsequently it is necessary to dispose of the CO_2. Historically the design of facilities for CO_2 removal is well proven and smaller quantities have simply been vented. However, the disposal of large quantities of CO_2 has been more problematic, and has hindered the development of otherwise attractive gas reserves.

The main motivation for separating CO_2 from gas fields with a high CO_2 concentration is to address issues to do with producing and selling on natural gas, and unless there is an additional incentive to store such CO_2 then it is likely to be vented. Further, should there be such an incentive, CO_2 does not need to be stored in a gas field. For example, CO_2 separated from natural gas production at Sleipner, Snøhvit and In Salah are all stored in aquifers. In summary any separation of CO_2 from natural gas with high concentrations of CO_2 is unlikely to have a material impact on the use of depleted gas fields for storing CO_2.

5.2 Role of CO_2 in enhanced gas recovery

5.2.1 Historical Background of Enhanced Gas Recovery (EGR)

Enhanced oil recovery (EOR) by flooding the reservoir with miscible CO_2 has been practiced worldwide since the 1960s and is considered a mature technology in the oil and gas industry. However the injection of CO_2 for enhanced gas recovery (EGR) is rarely practiced (Sim et al, 2008). The concept has been discussed for over 15 years but has not yet been commercially applied to a gas reservoir. The main reasons for this are likely to be:

- to date CO_2 has been a relatively expensive commodity;
- geologic carbon storage is not yet widely practiced; and
- there has been a concern that injected CO_2 would mix rapidly with the existing methane gas and so degrade the resource (Oldenburg, 2003).

The potential benefits of EGR may be considered in the context that recovery factors for gas reservoirs worldwide currently average approximately 75% (Laherrere, 1997). There is thus a significant potential gas resource in existing reservoirs which might be additionally produced if EGR were shown to be feasible and economically viable. In addition, the increasing attraction of geological sequestration of CO_2, and the associated development of capture and storage technology, is changing the economic value of CO_2 as a source of EGR.

Investigations into the feasibility of EGR have included both circulation of existing reservoir CO_2, called 'closed loop' systems, to produce additional natural gas, and combined systems of Carbon Storage and Enhanced Gas Recovery (CSEGR) where the CO_2 originates elsewhere, such as flue gas from a power plant or industrial process. CO_2 has also been assessed as a potential cushion gas for a natural gas storage facility, on completion of a CSEGR process.

5.2.2 Conclusions of Experimental Work

The mechanism of EGR by injection of CO_2 has been studied in a number of numerical simulation projects (e.g. Clemens, 2002; Oldenburg, 2003; Turta, 2003) and laboratory tests (e.g. Sim, 2008). The main conclusions of these studies may be summarised as follows:

- the mobility ratio of CO_2/methane is always favourable, so that the harmful effect of some mild heterogeneities can be cancelled;
- the density of CO_2 is at least two to six times higher than natural gas, so gravity stable displacement is feasible;
- mixing between injected CO_2 and existing methane may not be extensive, and it can potentially be controlled by operational strategies;
- EGR can be effective in depleting gas reservoirs when undertaken at an advanced stage of depletion, either by reservoir pressure increase or by balanced injection/withdrawal;
- the maximum incremental gas recovery observed in one reported simulation of a depleting gas reservoir was about 10% of Gas Initially In Place (GIIP);
- EGR, if undertaken early in the life of a depleting gas field, reduces the total recovery of methane compared to depletion alone;
- EGR can also be effective in water-drive gas reservoirs, where the dependency on stage of exploitation is not so strong. Pressure maintenance by CO_2 injection has the benefits of:
  - delaying the influx of the aquifer,
  - partially mitigating water coning caused by excessive pressure drawdown; and
- very high solubility of CO_2 in the connate water, compared to that of methane, makes the displacement even smoother, i.e. any breakthrough of CO_2 is delayed.

5.2.3 Field Testing

It is understood that to date only two field testing programmes of EGR by CO_2 injection have been undertaken:

5.2.3.1 Budafa Szinfeletti Field, Hungary

This project involved the injection of a mixture of 80% CO_2 and 20% methane into a depleted gas reservoir from a nearby natural CO_2 pool over an 8 year period from 1986 to 1994 (Turta, 2003). The primary reservoir depletion mechanism was a weak water drive.

EGR and CO_2 storage started when gas recovery had reached 67% of OGIP, and an incremental gas recovery of 11.6% of OGIP was observed over the period, i.e. 35% of the gas in place at the start of the test. This correlates quite well with the incremental recovery of 10% reported by one simulation project (Clemens, 2002).

5.2.3.2 Gaz de France K12-B Reservoir, Netherlands

The gas produced from this offshore field contains around 13% CO_2. The reservoir depth is 3,800m. Historically the CO_2 was separated from the produced natural gas and vented to the atmosphere. Due to favourable reservoir characteristics GdF decided to investigate the feasibility of CO_2 injection, supported by the Dutch CRUST initiative. K12-B was reported to be the first site in the world where CO_2 has been injected into the same reservoir from which it originated.

The project has been undertaken in phases, as follows.

- ***Phase 1*** (May – December 2004) successfully proved that injection was feasible and safe, and investigated the CO_2 phase behaviour and response of the reservoir.
- ***Phase 2*** (January 2005 – 2006) tested the feasibility and potential benefits of re-injecting the produced CO_2 into a nearly depleted reservoir compartment. Preliminary results were reported in December 2005 (van der Meer et al, 2006). These indicated 'no clear evidence of measurable improvement in the gas production performance of the tested compartment.' GdF committed itself to continue the test during 2006, but it is not known if the conclusion of Phase 2 has been reported, or if the project continued beyond 2006.

5.2.4 Ideal EGR Candidate Gas Reservoir Characteristics

The ideal characteristics of a candidate gas reservoir suitable for EGR by CO_2 injection have been elaborated as follows (Turta, 2003):

- heterogeneity should be relatively low so that incremental gas recovery of uncontaminated natural gas is high;
- gravity stable or quasi-stable displacement should be possible, e.g. high dip, high pay thickness;
- relatively high number of wells, at least 4 to 5, should be utilised in EGR operations; and
- the storage effect is highest for certain temperature and pressure conditions.

5.2.5 Conclusion on EGR

The above indicates that EGR is still at an early stage of development, and that where it is likely to take place it will be more the exception than the rule.

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6. SUMMARY CO_2 STORAGE CAPACITY IN DEPLETED GAS FIELDS

This study has produced three key findings:

- a revision to estimates of CO_2 storage capacity in depleted gas fields taking into account geological and economic issues as well as when gas fields will be available for CO_2 injection;
- identified sensible combinations of sources and sinks and pipeline networks; and
- developed global and regional marginal abatement curves for transporting CO_2 to and storing it in depleted gas fields.

The study has substantially reduced the estimate of CO_2 storage capacity in depleted gas fields from 797 Gt that was reported in the IEA GHG study of 2000, to

- 651 Gt once associated gas has been excluded and it is assumed that CO_2 will only occupy 75% of the pore space;
- 387 Gt once gas fields that are too small to be economically viable have been excluded and capacity has been reduced to account for potential storage security;
- 260 Gt in 2050 after adjusting for when giant gas fields will become available for CO_2 injection; and
- 158 Gt in 2050 when giant gas fields that are too remote have been excluded.

To put these capacity estimates in perspective, average annual CO_2 emissions in 2015 from stationary sources emitting more than 1 $MtCO_2$ pa are predicted to be approximately 12 Gt. The analysis indicates that depleted gas fields that are available in 2050 could only store 13 years of this volume of CO_2.

The predicted available capacity from giant gas fields appears sufficient, in principle, to accommodate the CCS uptake scenarios recently proposed by the International Energy Agency (IEA) by 2050[13]. Over the longer term, and in the light of likely additional technical, economic, political, social and regulatory constraints on specific projects, oilfields and saline aquifers would also need to be developed if CCS is to make its full contribution to dangerous climate change at lowest overall cost.

Abatement curves were derived from an analysis of commitments to store 60 Gt CO_2 in 222 giant gas fields. This analysis indicates that as 30 Gt of CO_2 can be transported and stored for less than \$5 per tonne, rising to 50 Gt of CO_2 being transported and stored for less than \$10 per tonne, the costs of storing CO_2 in depleted gas fields is lower than the many published capture costs, which are typically estimated at least \$30/t CO_2.

These findings for the revised storage capacity estimates and marginal abatement curves are outlined below, while the maps showing the pipeline networks connecting sources and giant gas fields are presented in section 4.7.

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[13] See IEA *Energy Technology Analysis: CO_2 capture and storage – a key carbon abatement option*, (October 2008).

6.1.1 Revised estimates of storage capacity

Table 19 below summarises this studies estimates of cumulative theoretical, effective and practical CO_2 storage capacity, based on the USGS global assessments, and the matched CO_2 storage capacity based on giant gas fields. The analysis of the USGS Assessment data does not consider when gas fields will become available for storing CO_2, and so the estimated capacities do not change over time, whereas the analysis based on giant gas fields does consider when they will become available and so increases over time.

Table 19 – Estimated cumulative storage capacity in depleted gas fields (Gt)

Decade	Theoretical	Effective	Practical	Matched
By 2020	868	651	387	33
By 2030				89
By 2040				137
By 2050				158

Note: The theoretical, effective and practical estimates are based on USGS Global Assessments data and are constant over time while the matched estimates are based on the Giant Fields Atlas and change as sinks become available.

The key points that emerge from this part of the analysis are listed below.

- The estimate of storage capacity from the Initial Study was of 797 Gt, which took into account edge effects, which is predominately water entering and taking up space in the reservoir. This means that the most suitable comparison from this study is with our estimate of effective capacity, which is 651 Gt. This is lower than the estimate from the Initial Study and is largely due to our exclusion of associated gas.
- The estimate practical capacity is significantly lower than the estimate of effective capacity, which shows the impact of removing gas fields that are too small to be cost effective for storing CO_2 or are not considered suitable due to the risk of potential storage security.
- The impact of when giant gas fields become available for injecting CO_2 further reduces capacity estimates. The matching of 566 large CO_2 sources with 266 giant gas fields that are sufficiently close yields a matched storage capacity estimate of 33 Gt by 2020 rising to 158 Gt by 2050.

With regard to CO_2 storage capacity in depleted gas fields for different regions, we have estimated the theoretical, effective and matched capacity using the USGS TPS data and matched capacity through linking sources with giant gas fields. There are slight differences in the definitions of regions used in each analysis so the results from the former are shown in Table 20 below, while those from the latter are shown in Table 21 overleaf.

Table 20 – Estimates of regional CO_2 storage capacity in gas fields (Gt)

Region	Theoretical	Effective	Practical
Asia-Pacific	101	75	45
Central and South America	60	45	27
Europe	83	62	37
Former Soviet Union	341	256	152
North America	75	56	33
Middle East & Africa	238	178	106
Total	**897**	**673**	**400**

Source: USGS Total Petroleum System data

Table 21 – Estimates of matched regional CO_2 storage capacity in gas fields (Gt)

Region	By 2020	By 2030	By 2040	By 2050
North America	11	15	17	17
South/Central America	2	5	6	8
Western Europe	4	9	11	11
Eastern Europe/FSU	7	21	38	47
Middle East	6	25	32	33
Africa	1	11	13	13
Asia & Oceania	2	5	19	28
Total	**33**	**89**	**137**	**158**

Source: Giant Fields Atlas

The results of the analysis indicates that:

- There is significant capacity within Asia, much of which will become available in the second half of the period being considered. However, there is insufficient capacity to store significant levels of emissions from China, India and Japan.
- The storage capacity in Australia is primarily located in the north-west, and to a lesser degree in central Australia, which is remote from the bulk of CO_2 sources located on the eastern and south-eastern coast.
- The Middle East and the Former Soviet Union have significant levels of capacity, and as much of it is located significant distances from large stationary CO_2 sources, it will take an extended period of time to fill.
- The storage capacity in Europe is primarily located in the North Sea, and while this will accept a significant volume of CO_2, it will not be possible to store the bulk of CO_2 emissions from large stationary sources in depleted gas fields.
- Most of the capacity of giant gas fields in North America is onshore, close to large stationary sources and is expected to be available early in the time frame being considered. However, these will only be capable of accepting a small proportion of total emissions.
- The capacity in South America seems capable of storing a substantial proportion of emissions, however, this may change should the level of CO2 emissions grow significantly.

- The bulk of the storage capacity in Africa is located in north, and there does not appear to be sufficient capacity to store CO_2 from the large sources in eastern South Africa.

6.1.2 Marginal abatement curves

The modelling process connected a total of 566 sources to 233 giant gas fields, but there was only sufficient information available to determine the costs for transport to and storage at 222 of the sinks. The costing analysis is based on the costs associated with transporting and storing the CO_2 the 222 gas fields are committed to store, which is 60 Gt CO_2. The NPV costs per lifetime tonne of CO_2 stored in these giant gas fields, reported in US$ 2008 currency, have been ranked and are presented in Figure 29 below.

Figure 29 – Marginal abatement curve for transport and storage

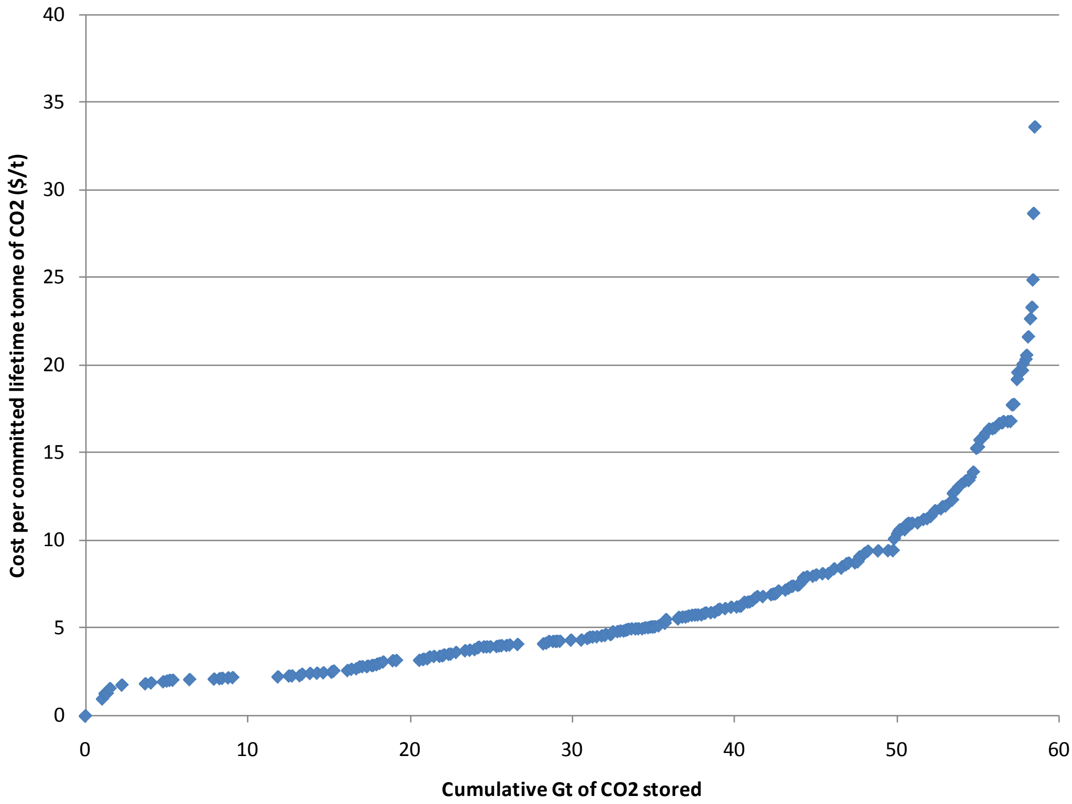

Figure 29 above indicates that:

- 30 Gt of CO_2 storage capacity is available at costs below $5 per lifetime tonne for transport and storage;
- 50 Gt of CO_2 storage capacity is available at costs less than $10 per lifetime tonne for transport and storage; and
- beyond 50 Gt of CO_2 storage capacity, the marginal cost curve increases exponentially.

For storage in giant depleted gas fields connected to large sources, the costs for transport and storage are lower than the majority of published capture costs, which are typically estimated at least \$30/t CO_2.

The analysis indicated that regions where:

- there are large onshore gas fields that are close to sources, such as Asia, Former Soviet Union and North America, have the lowest unit costs;
- the distance between sinks and sources increase, and particularly as more offshore pipes are used, such as in the Middle East and Europe, the cost increases; and
- there are large distances between sinks and sources and the volume of CO_2 transported is small, such as in South America and Africa, the costs are the highest.

6.1.3 Other findings

This study also considered:

- competition for depleted gas fields between storing natural gas and storing CO_2;
- the expected development of gas fields with high concentrations of CO_2; and
- the impact of using CO_2 for enhanced gas recovery.

The outcomes were that there is unlikely to be a material competition for depleted gas fields between storing natural gas and storing CO_2, as they require different types of fields, particularly storing:

- natural gas is preferable in fields that have capacity no greater than 3 bcm of natural gas, as they do not require substantial volumes of cushion gas and the pressure can build up quickly to facilitate rapid withdrawal; and
- CO_2 is preferred in fields that have capacity of at least 20 bcm of natural gas, as they can accept large volumes of CO_2 over a long period of time and the pressure increases gradually.

The review of separating CO_2 from gas produced from fields with high concentrations of CO_2 indicates that the main motivation is to address issues to do with producing and selling on natural gas and that unless there is an additional incentive to store such CO_2 then it is likely to be vented. Further, should there be such an incentive, CO_2 could be stored in a depleted gas field or an alternative reservoir as is currently taking place at Sleipner, Snøhvit and In Salah. In summary we do not consider that any separation of CO_2 from natural gas with high concentrations of CO_2 will have a material impact on the use of depleted gas fields for storing CO_2.

With regard to EGR, this is still at an early stage of development, and it is likely that where it will be used it will be more the exception than the rule.

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ANNEX A – SUPPLEMENTARY INFORMATION

A.1 Glossary and acronyms

Table 22 – Glossary and acronyms

AAPG	American Association of Petroleum Geologists
AU	Assessment Unit
bcm	Billion cubic metres
Bg	Formation volume factor, or the reciprocal of the GEF, assumed to be 0.05
BGS	British Geological Survey
CCS	Carbon capture and storage
CO_2	Carbon dioxide
CoP	Close of production
CSLF	Carbon Sequestration Leadership Forum
EGR	Enhanced Gas Recovery
EU	European Union
GEF	Gas Expansion Factor, assumed to be 200
GOR	Gas to oil ratio
FSU	Former Soviet Union
Gt	Giga, or 1,000,000,000, metric tonnes
IEA	International Energy Agency
IEA GHG	IEA Greenhouse Gas R&D Programme
Mt	Million, or 1,000,000, metric tonnes
NGLs	Natural Gas Liquids
pa	Per annum or per year
scf	Standard cubic feet
STP	Standard Temperature and Pressure
tcf	Trillion cubic feet
TPS	Total Petroleum System
URR	Ultimate Recoverable Reserve
USGS	United States Geological Survey

A.2 Groupings of TPS by country or region

Table 23 –TPSs grouped by country or region

Region/country	TPS codes
Canada	524401, 524402, 524403, 524404, 524301, 524302, 524303, 524304, 524305, 524306, 521501, 521502
South America	604101, 604102
Africa including Red Sea	720301, 720302, 204801, 204802
Middle East	201901, 201902, 201903, 201601, 201602, 202101, 202102, 201401, 203001, 203002, 202301, 202302
Europe	404702, 404703, 404701, 406001, 406002
Central Asia/Russia	115001, 115002, 115003, 117401, 117402, 311501, 311502, 311503
China	314201, 314202, 314203, 314204, 312801, 312802, 312701, 312702, 314401, 314402
India	804701, 804702
Gulf of Thailand	370301, 370302
Indonesia	382402, 382403
Australia	391001, 391002, 391003, 394801, 394802

ANNEX B – GAS FIELDS DATA

The following tables provide details on the global CO_2 storage capacity based on an analysis of the TPS based in Assessment Units. The total estimate of an effective storage capacity of 673 Gt is slightly greater than the estimate of 651 Gt based on the USGS global estimates given in the report. This difference is due to the fact that different data sets were used for certain elements of the analysis. The differences between these data sets were outlined in section 2, and the different outcomes are probably due mainly to an:

- under-estimate of the associated gas in the analysis based on Assessment Units; and/or
- over-estimate of the associated gas in the USGS global estimates.

Our view is that our analysis of the USGS global estimates is likely to be more reliable, because the arithmetic mean global gas-to-oil ratio is used, and hence we have used the figures derived from them in our estimates. However, we consider that our analysis based on the USGS Assessment Units is still useful because it provides estimates of CO_2 storage capacity by region.

Table 24 – Estimate of global CO_2 storage capacity by region

Region	Total known conventional gas (tcf)	Est Grown Gas (tcf)	Undiscovered gas (tcf)	Estimated total conventional gas (tcf)	Estimated total gas in gas fields (tcf)	Total gas in gas fields (10^9 m^3)	Estimated CO_2 storage capacity 10^9 tonnes
Asia-Pacific	435	691	459	1,150	913	25,846	75
Central and South America	278	416	517	932	684	19,383	45
Europe	484	643	312	956	833	23,583	62
Former Soviet Union	2,022	2,481	1,611	4,092	3,479	98,536	256
North America	874	1,154	370	1,524	756	21,408	56
Middle East & Africa	2,015	2,738	1,660	4,399	2,724	77,158	178
Total	**6,109**	**8,124**	**4,929**	**13,053**	**9,389**	**265,916**	**673**

Source: USGS

Table 25 – Estimate of CO_2 storage capacity in Asia Pacific

TPS Name	Total known conventional gas (tcf)	Est Grown Gas (tcf)	Undiscovered gas (tcf)	Estimated total conventional gas (tcf)	Estimated total gas in gas fields (tcf)	Total gas in gas fields (10^9 m^3)	Estimated CO_2 storage capacity 10^9 tonnes
Lucaogou-Karamay/Ulho/Pindequan	2	2	0	3	0	0	0
Jurassic Coal-Jurassic/Tertiary	0	1	1	2	1	39	0
Lucaogou/Jurassic Coal-Paleozoic/Mesozoic	0	0	0	0	0	0	0
Shahejie-Shahejie/Guantao/Wumishan	16	20	9	29	10	297	1
Carboniferous/Permian Coal-Paleozoic	0	0	0	0	0	0	0
Yanchang-Yanan	0	0	0	0	0	0	0
Taiyuan/Shanxi-Majiagou/Shihezi	6	11	0	11	11	312	1
Maokou/Longtang-Jialingjiang/Maokou/Huanglong	0	1	2	2	2	63	2
Daanzhai-Daanzhai/Lianggaoshan	0	0	0	0	0	0	0
Xujiahe-Xujiahe/Shaximiao	0	0	0	0	0	0	0
Cambrian/Silurian Marine Shale-Dengying/Lower Paleozoic	1	2	4	6	6	169	0
Qingshankou-Putaohua/Shaertu	2	3	2	5	3	77	0
Jurassic Coal-Denglouku/Nongan	0	0	3	3	3	96	0
Ordovician/Jurassic-Phanerozoic	6	13	60	73	51	1,446	4
Brunei-Sabah	36	56	23	79	46	1,297	3
Sarawak Basin	37	57	17	74	71	2,005	5
East Natuna	45	65	2	67	67	1,885	5
Oligocene-Miocene Lacustrine	24	41	24	65	36	1,023	3
Miocene Coaly Strata	24	33	4	37	32	904	2
Brown Shale-Sihapas	4	6	4	11	1	42	0
Kutei Basin	0	0	29	29	18	513	8
Bampo-Cenozoic	26	34	15	50	48	1,348	4
Banuwati-Oligocene/Miocene	1	1	1	2	0	8	0
Jatibarang/Talang Akar-Oligocene/Miocene	7	12	7	19	13	382	1
Tertiary-Parigi	0	0	0	0	0	7	0
Tertiary-Cenozoic	0	0	0	0	0	0	0
Lahat/Talang Akar-Cenozoic	10	17	18	35	29	824	2
Milligans-Carboniferous/Permian	0	0	1	1	1	25	0
Keyling/Hyland Bay-Permian	6	8	11	19	19	545	1
Jurassic/Early Cretaceous-Mesozoic	8	25	11	36	31	868	2
Late Jurassic/Early Cretaceous-Mesozoic	18	23	20	43	39	1,117	3
Latrobe	10	12	6	18	4	110	0
Dingo-Mungaroo/Barrow	48	98	56	154	141	4,005	11
Locker-Mungaroo/Barrow	8	12	8	20	20	565	1
Patala-Namal	2	4	1	5	3	81	0
Sylhet-Kopili/Barail-Tipam Composite	7	8	1	9	1	18	0
Sembar-Goru/Ghazij	35	52	29	82	81	2,281	6
Eocene-Miocene Composite	24	37	13	50	16	446	1
Permian Coal	0	0	0	0	0	0	0
Jalangi-Sylhet/Burdwan Composite	0	0	5	5	4	127	0
Jenam/Bhuban-Bokabil	12	21	50	72	72	2,031	5
Eocene to Miocene Composite	10	16	21	37	32	893	2
Total	**435**	**691**	**459**	**1,150**	**913**	**25,846**	**75**

Source: USGS

Table 26 – Estimate of CO_2 storage capacity in Central and South America

TPS Name	Total known conventional gas (tcf)	Est Grown Gas (tcf)	Undiscovered gas (tcf)	Estimated total conventional gas (tcf)	Estimated total gas in gas fields (tcf)	Total gas in gas fields (10^9 m^3)	Estimated CO_2 storage capacity 10^9 tonnes
Cenomanian-Turonian	0	0	42	42	12	329	1
Neogene	0	0	30	30	30	845	0
Neocomian to Turonian Composite	1	2	8	10	5	138	0
Cretaceous Composite	0	0	34	35	28	784	1
Lagoa Feia-Carapebus	6	9	20	29	2	52	0
Guaratiba-Guaruja (Cretaceous) Composite	1	2	81	83	41	1,153	3
Cenomanian-Turonian-Tertiary Composite	0	0	23	23	16	463	1
Mesozoic-Cenozoic	2	2	2	4	1	24	0
Paleozoic	17	25	21	46	45	1,261	3
Los Monos-Machareti	17	26	18	44	36	1,029	3
Neuquen Hybrid	7	9	8	17	6	173	0
D-129	1	1	1	2	1	33	0
Aguada Bandera	25	35	10	45	45	1,276	3
Lower Inoceramus	0	0	13	13	4	109	0
Neocomian Lacustrine	0	0	8	8	5	155	0
Lower Cretaceous	0	0	11	11	9	265	1
Lower Cretaceous Marine	3	3	5	8	0	0	0
Cretaceous-Tertiary	0	0	0	1	1	25	0
Neogene	0	0	30	30	30	845	0
Cretaceous-Paleogene	3	4	0	4	2	61	0
La Luna-La Paz	17	53	5	58	52	1,468	4
Gacheta-Mirador	53	75	25	101	71	2,003	5
Querecual	76	101	44	145	124	3,520	9
Upper Cretaceous/Tertiary	25	31	44	76	51	1,457	4
La Luna/Maracaibo	24	36	22	58	56	1,576	4
Lower Cruse	0	0	12	12	12	339	1
Tobago Trough Paleogene	0	0	0	0	0	0	0
Upper Jurassic-Neocomian	0	0	1	1	0	0	0
Total	**278**	**416**	**517**	**932**	**684**	**19,383**	**45**

Source: USGS

Table 27 – Estimate of CO_2 storage capacity in Europe

TPS Name	Total known conventional gas (tcf)	Est Grown Gas (tcf)	Undiscovered gas (tcf)	Estimated total conventional gas (tcf)	Estimated total gas in gas fields (tcf)	Total gas in gas fields (10^9 m^3)	Estimated CO_2 storage capacity 10^9 tonnes
Upper Jurassic Spekk	16	29	165	195	162	4,579	12
Kimmeridgian Shales	159	230	38	268	199	5,649	15
Carboniferous-Rotliegend	222	273	26	299	297	8,398	22
Isotopically Light Gas	11	13	2	16	16	446	1
Mesozoic/Paleogene Composite	5	6	2	8	4	113	0
Paleozoic Composite	0	0	0	1	1	17	0
Greater Hungarian Plain Neogene	10	13	2	15	14	388	1
Zala-Drava-Sava Mesozoic/Neogene	4	6	1	7	5	145	0
Danube Neogene	0	0	0	0	0	13	0
Transcarpathian Neogene	0	0	0	0	0	14	0
Central Carpathian Paleogene	0	0	0	0	0	0	0
Hungarian Paleogene	0	0	0	0	0	8	0
Transylvanian Composite	31	38	2	40	40	1,133	3
Porto Garibaldi	18	24	16	40	40	1,129	3
Meride/Riva di Solto	0	1	2	2	0	11	0
Moesian Platform Composite	2	3	1	4	1	15	0
Dysodile Schist-Tertiary	5	6	3	9	3	98	0
Pre-Messinian	0	0	51	51	50	1,426	4
Total	**484**	**643**	**312**	**956**	**833**	**23,583**	**62**

Source: USGS

Table 28 – Estimate of CO_2 storage capacity in the Former Soviet Union

TPS Name	Total known conventional gas (tcf)	Est Grown Gas (tcf)	Undiscovered gas (tcf)	Estimated total conventional gas (tcf)	Estimated total gas in gas fields (tcf)	Total gas in gas fields (10^9 m^3)	Estimated CO_2 storage capacity 10^9 tonnes
Domanik-Paleozoic	37	42	35	77	60	1,691	4
Dnieper-Donets Paleozoic	59	66	24	91	85	2,402	6
Volga-Ural Domanik-Paleozoic	96	113	2	116	95	2,694	7
Belsk Basin	3	3	2	5	4	125	0
Paleozoic North Caspian	106	153	119	272	204	5,790	13
South and North Barents Triassic-Jurassic	78	160	267	427	424	12,008	32
Azov-Kuban Mesozoic-Cenozoic	19	20	12	32	31	868	2
Terek-Caspian	8	9	28	37	21	585	2
South Mangyshlak	6	6	2	9	0	0	0
Stavropol-Prikumsk	13	14	10	23	19	533	1
Oligocene-Miocene Maykop/Diatom	36	42	173	216	134	3,800	10
Buzachi Arch and Surrounding Areas Composite	1	1	0	1	1	30	0
North Ustyurt Jurassic	1	2	2	4	4	106	0
North Ustyurt Paleozoic	0	0	9	9	9	241	0
Amu-Darya Jurassic-Cretaceous	231	272	164	436	426	12,069	32
Bazhenov-Neocomian	98	117	97	214	0	0	0
Togur-Tyumen	5	6	6	12	0	0	0
Northern West Siberian Mesozoic Composite	1,167	1,370	540	1,911	1,816	51,425	135
Yenisey Foldbelt Riphean-Craton Margin Riphean	5	6	17	23	17	474	1
Baikal-Patom Foldbelt Riphean-Craton Margin Vendian	30	44	46	90	68	1,913	5
North Sakhalin Neogene	22	33	57	91	63	1,782	5
Total	**2,022**	**2,481**	**1,611**	**4,092**	**3,479**	**98,536**	**256**

Source: USGS

Table 29 – Estimate of CO_2 storage capacity in the Middle East and Africa

TPS Name	Total known conventional gas (tcf)	Est Grown Gas (tcf)	Undiscovered gas (tcf)	Estimated total conventional gas (tcf)	Estimated total gas in gas fields (tcf)	Total gas in gas fields (10^9 m^3)	Estimated CO_2 storage capacity 10^9 tonnes
Madbi Amran/Qishn	17	31	17	48	22	617	2
North Oman Huqf-Shu'aiba	28	45	18	64	45	1,260	3
Middle Cretaceous Natih	3	5	0	5	4	105	0
Cretaceous Thamama/Wasia	102	137	22	160	79	2,232	6
Jurassic Hanifa/Diyab-Arab	78	105	59	163	75	2,117	6
Silurian Qusaiba	452	651	347	998	958	27,133	50
Central Arabia Qusaiba Paleozoic	79	122	383	506	458	12,967	34
Arabian Sub-Basin Tuwaiq/Hanifa-Arab	275	344	34	378	169	4,784	13
Paleozoic Qusaiba/Akkas/Abba/Mudawwara	2	3	65	67	60	1,698	4
Jurassic Gotnia/Barsarin/Sargelu/Najmah	0	0	23	23	16	449	1
Zagros-Mesopotamian Cretaceous-Tertiary	493	643	198	841	74	2,089	5
Paleozoic-Permian/Triassic	131	209	69	278	278	7,880	21
Sirte-Zelten	38	42	15	57	25	695	2
Bou Dabbous-Tertiary	16	23	3	26	18	515	1
Jurassic-Cretaceous Composite	1	2	2	4	3	82	0
Tanezzuft-Oued Mya	9	10	2	12	1	35	0
Tanezzuft-Melrhir	0	0	5	5	2	70	0
Tanezzuft-Ghadames	16	24	12	36	18	501	1
Tanezzuft-Illizi	45	52	28	80	47	1,321	3
Tanezzuft-Timimoun	4	5	1	6	6	168	0
Tanezzuft-Ahnet	3	5	3	8	8	237	1
Tanezzuft-Sbaa	1	4	1	4	4	109	0
Tanezzuft-Mouydir	0	0	0	0	0	7	0
Tanezzuft-Benoud	105	126	3	129	128	3,621	10
Tanezzuft-Bechar/Abadla	0	0	0	0	0	11	0
Sudr-Nubia	6	7	10	18	4	111	0
Maqna	4	7	50	56	50	1,410	4
Cretaceous-Tertiary Composite	0	0	1	1	1	17	0
Cretaceous Composite	0	0	34	35	28	784	1
Tertiary Niger Delta (Agbada/Akata)	94	117	133	250	100	2,830	7
Melania-Gamba	1	1	4	5	0	0	0
Azile-Senonian	2	2	13	16	5	133	0
Congo Delta Composite	9	14	70	84	13	367	1
Cuanza Composite	0	0	2	2	1	20	0
Cretaceous Composite	0	0	34	35	28	784	1
Total	**2,015**	**2,738**	**1,660**	**4,399**	**2,724**	**77,158**	**178**

Source: USGS

Table 30 – Estimate of CO_2 storage capacity in North America

Province/TPS Name	Total known conventional gas (tcf)	Est Grown Gas (tcf)	Undiscovered gas (tcf)	Estimated total conventional gas (tcf)	Estimated total gas in gas fields (tcf)	Total gas in gas fields (10^9 m^3)	Estimated CO_2 storage capacity 10^9 tonnes
Montana Thrust Belt	0	0	8	8	8	237	1
Eastern Oregon/Washington	0	0	0	0	0	9	0
Powder River Basin	1	2	1	2	1	24	0
Wind River Basin	3	4	0	4	3	80	0
Wyoming Thrust Belt	5	6	0	7	5	148	0
Southwestern Wyoming	10	13	2	15	13	363	1
Denver Basin	1	2	0	2	1	15	0
Hanna Basin	0	0	0	0	0	5	0
Eastern Great Basin	0	0	2	2	2	44	0
Uinta Piceance Basin	1	1	0	1	1	19	0
San Juan Basin	0	0	0	0	0	5	0
Raton Basin	0	0	1	1	1	22	0
Sacramento Basin	9	12	1	13	13	357	1
San Joaquin Basin	13	15	1	17	2	46	0
Permian Basin	94	126	4	130	43	1,205	3
Fort Worth Basin	8	9	0	9	7	212	1
Gulf Coast Region	329	412	109	521	136	3,860	10
Florida Peninsula	0	0	0	0	0	0	0
Black Warrior Basin	2	5	1	7	7	187	0
Illinois Basin	0	0	1	1	1	17	0
Appalachian Basin	0	0	4	4	4	115	0
Michigan Basin	4	5	2	7	4	123	0
Bighorn Basin	2	2	0	3	0	10	0
Northern Alaska	33	44	50	94	56	1,583	4
Anadarko Basin	93	125	14	139	133	3,761	10
Palo Duro Basin	48	65	0	65	60	1,701	4
Los Angeles Basin	7	9	2	11	2	42	0
Ventura Basin	6	8	5	12	5	130	0
Southern Oklahoma	3	4	1	5	1	28	0
Arkoma Basin	16	21	2	23	20	575	2
Southern Alaska	8	10	2	12	9	243	1
Nemaha Uplift	3	4	0	4	0	11	0
Cambridge Arch-Central Kansas Uplift	1	1	0	1	0	8	0
Cherokee Platform	1	2	0	2	0	6	0
Santa Maria Basin	2	2	1	3	1	17	0
Sedgewick Basin	2	3	0	3	1	16	0
Permian/Upper Jurassic Composite	0	0	81	81	34	950	2
Egret-Hibernia	2	4	9	13	0	0	0
Mesozoic Composite	4	6	0	6	6	172	0
Keg River-Keg River	7	10	2	12	10	296	1
Duvernay-Leduc	14	21	3	24	16	445	1
Exshaw-Rundle	22	31	3	34	33	926	2
Combined Triassic/Jurassic	11	15	2	17	17	469	1
Mannville-Upper Mannville	31	44	5	49	49	1,383	4
Second White Specks-Cardium	26	38	1	39	38	1,067	3
Yeoman	0	0	0	0	0	0	0
Brightholme	0	0	0	0	0	0	0
Bakken	0	0	0	0	0	0	0
Lodgepole	1	1	0	1	0	0	0
Pimienta-Tamabra	51	72	49	121	17	473	1
Total	**874**	**1,154**	**370**	**1,524**	**756**	**21,408**	**56**

Source: USGS

ANNEX C – WORKED EXAMPLE – EUNICE GIANT GAS FIELD USA

The following presents a worked example for the network connection algorithm and cost model. The model identifies two Southwestern Service Company power stations in Lubbock and Lamb Counties, which connects SW1 and SW2 to Eunice in 2011. This is known as Project 1 and is represented by red lines in Figure 30 below. In the period 2021 two more sources connect, AEP Nugs power station and El Paso power station. This is known as Project 2 and is represented by yellow lines in Figure 30 below.

Sources are selected in the following order, SW1, SW2, AEP Nugs, El Paso based on their size, which is shown by the size of their symbol, and proximity to Eunice. There are also several sources in closer proximity to Eunice, which are already taken up by Gomez gas field to the South. In 2021 Eunice also *loses* TXU to the marginally closer Puckett gas field.

Pipelines are designed such that sources connecting to the sink in a given decade can join to produce a tree and branch pipeline configuration (e.g. Project 1) unless connecting directly to the sink produces shorter pipelines (e.g. Project 2).

Figure 30 – Eunice gas field, South West USA

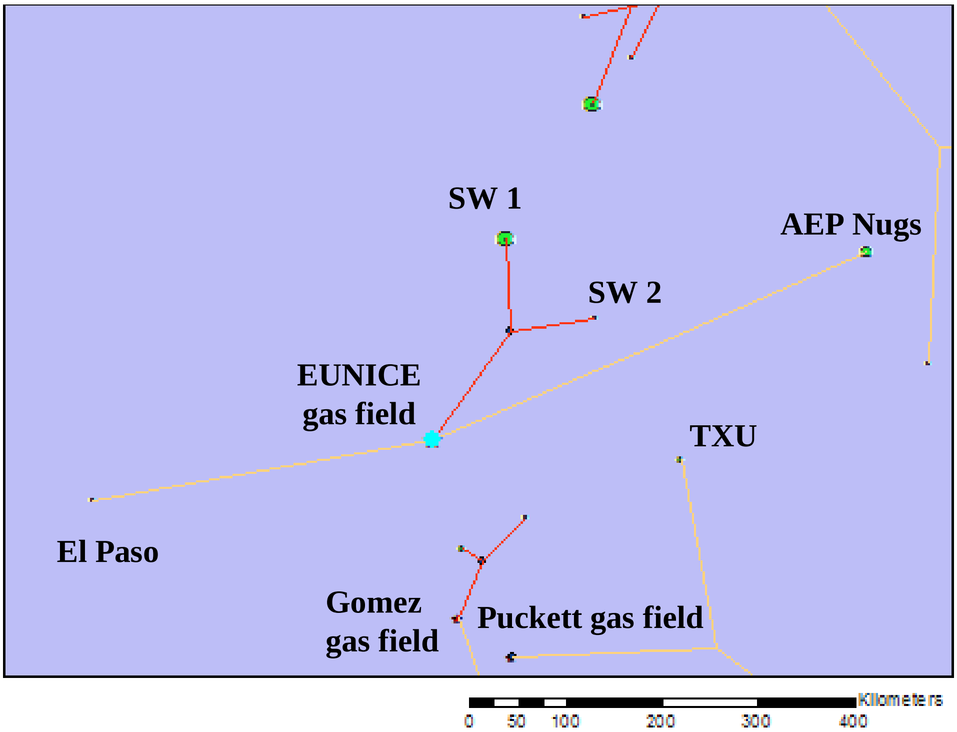

Table 31 overleaf summarises the characteristics of the Eunice giant gas field.

Table 31 – Characteristics of Eunice gas field

Gas field	Eunice, USA
CoP date	1987
Total CO_2 transported	481 mt
Total costs $m (project 1 + 2)	1,879
Cost per lifetime CO_2 transported (for all projects)	$3.91
Remaining storage capacity	121 mt

The analysis included calculating the following costs:

- pipeline capital costs, based on the diameters, onshore and offshore lengths cost of pipelines for the given flow of CO_2;
- booster costs, based on the boosting required as pressure drops along the pipeline;
- drilling costs, based on the number of wells required for the given CO_2 flow for a given field and the water and reservoir depth;
- injection costs, based on the type and number of injection facilities required based on the field location and number of wells required; and
- monitoring costs, which are calculated yearly on the throughput of CO_2 for 50 years from the start of the project.

Annual operational costs for pipelines boosters and facilities are assumed to be a percentage of capital expenditure. In addition electricity costs are added to operational costs for boosting.

All annual operating expenditure is discounted back to the start of the project based on the following assumptions:

- the discount rate is 10%;
- the project lifetime and discount period is 30 years; and
- the monitoring period is 50 years.

Figure 31 overleaf examines the total cost of each project, that is Project 1 connects two sources in 2011-2020 and Project 2 connects two additional sources in 2021-2030. Costs are subdivided into their constituent parts, resulting from pipelines, boosters, injection facilities, drilling and monitoring. All operational expenditure is discounted to the start of the relevant project.

The sum of the two columns gives the overall cost for the field and associated networks, as listed in table 25. This can then be divided by the total CO_2 transported over the project lifetimes to obtain a cost per lifetime tonne of CO_2.

Figure 31 – Costs of projects linked to Eunice

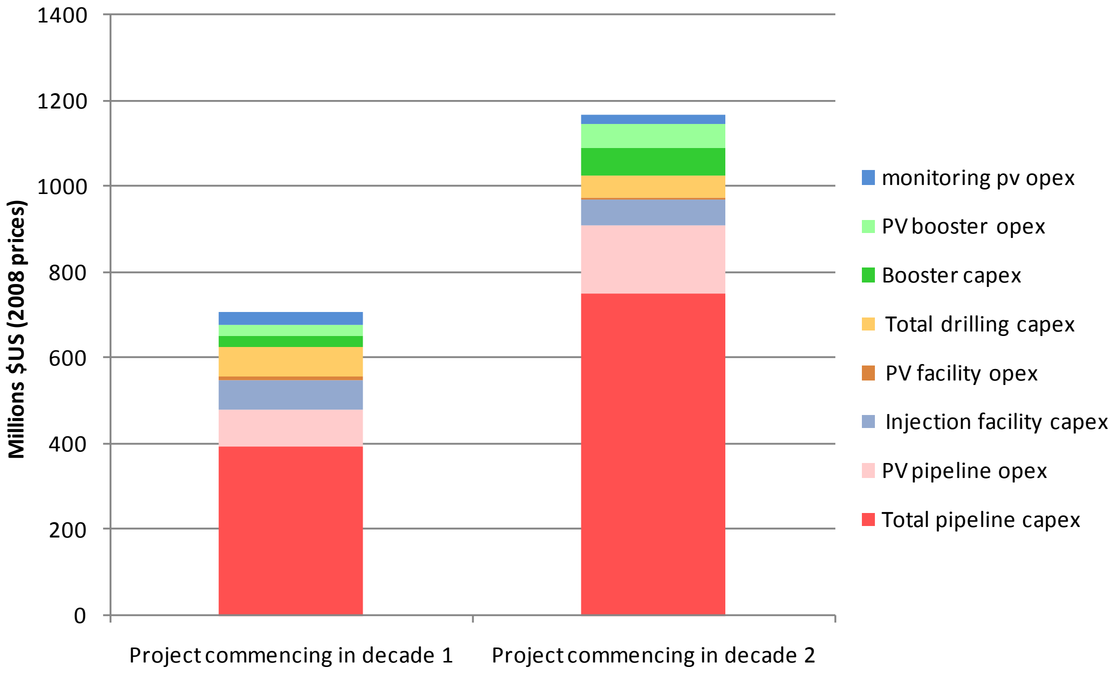

Table 32 overleaf shows a breakdown of the calculations used to estimate the costs for project 1 shown above, while Table 33 overleaf shows the costs for the addition of project 2 to the Eunice network. The equations used to calculate the costs in this section were based on the IEA GHG Study 2007/12 *Distributed Collection of CO_2*. The present value of operating costs was again calculated using the assumptions listed above. Pressures in the pipeline were limited as follows:

- minimum pressure 85bar (on and offshore);
- maximum pressure onshore 150 bar; and
- maximum pressure offshore 250 bar.

Table 32 – Results from Project 1

Sink Name	Eunice (Jalmat, Monument)		
Sink Storage capacity		601	Mt
Decade of availability		1	
Connections D1			
t CO2 link 1		7,952,237	t/yr
t CO2 link 2		1,303,857	t/yr
Mass flow rate		9.26	Mt/year
taken capacity		278	Mt
Pipelines			
Number of pipes		3	
Diameter - 1		517	mm
Length - 1		87055	metres
Diameter - 2		209	mm
Length - 2		73572	metres
Capex -branches		$204,995,498	dollars
Diameter - Trunk		558	mm
Total Length - Trunk		121349	metres
onshore Length - Trunk		121349	
offshore Length - Trunk		0	
Total Capex of trunk		$192,234,927	dollars
Pipeline annual opex		2%	
Pipeline annual opex	$	7,944,608	
Pipeline pv opex		**£82,382,459**	
Total pipeline capex	**$**	**397,230,425**	dollars
Boosters			
Maximum Pressure drop along a branch		4714.39192	kPa
Branch boosting required?	no		
Volumetric flow rate into node		294	kg/s
Node booster		2.306192644	MW
Coastline booster /trunk boosters not required in this case			
Booster opex		4%	
Booster opex /$/year	$	1,109,666	
Annual electricity/$	$	1,381,834	
booster + electricity annual opex	$	2,491,499	
booster + electricity pv opex		$25,835,866	
Capex for booster		$27,741,640	
Wells			
Reservoir Depth		10.00	
Water depth category		0	
Rig type		Land Rig	
Number of wells required		16	
Drilling cost	$	4,246,581	$/well
Total drilling capex	**$**	**69,104,124**	
Facilities			
Type of platform		Land Rig	
capex D1	$	70,676,716.87	
Number of platforms required		1	
Facility opex		1%	
Annual facility opex	$	706,767.17	
pv facility opex	**$**	**7,328,897**	
Total facility capex	**$**	**70,676,717**	
Monitoring			
monitoring opex	$	138,841,409.90	
monitoring pv opex	**$**	**30,284,910.09**	

Table 33 – Results from Project 2

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ANNEX D – ECONOMIC SENSITIVITY ANALYSIS

The following summarises the findings from the following sensitivity analyses:

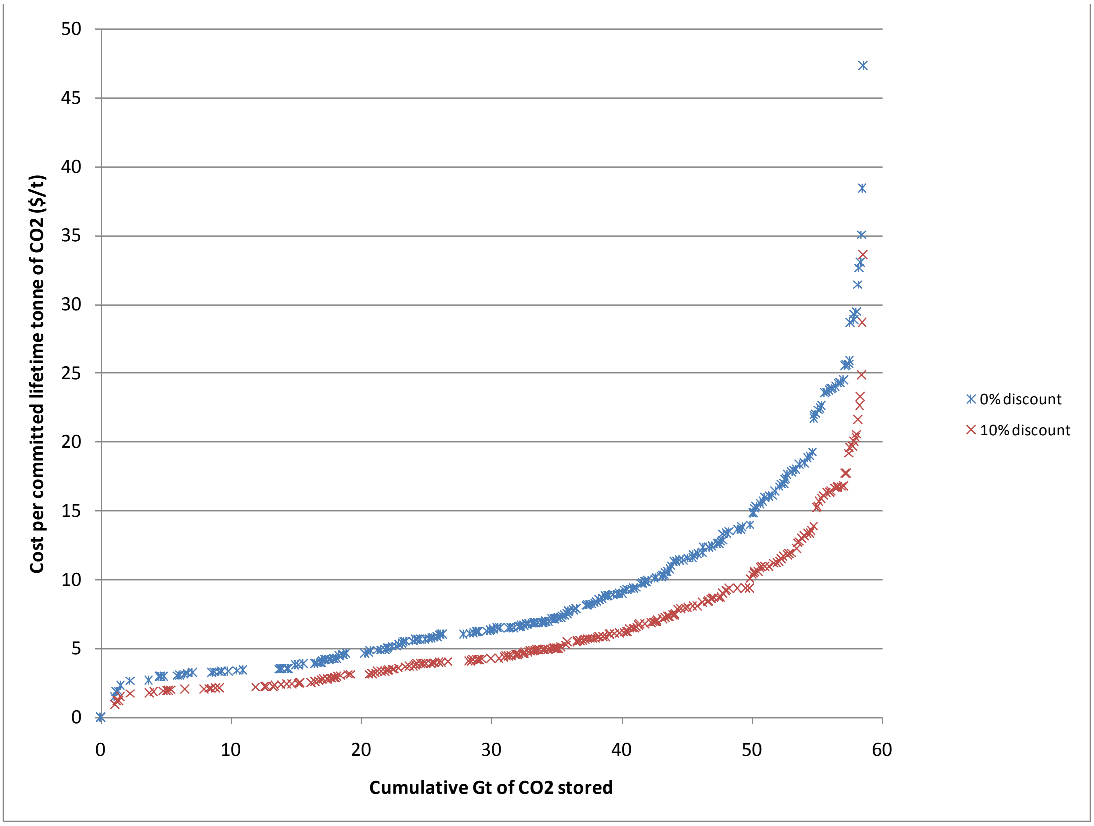
- varying the discount rate;
- removing the radius of search;
- varying the length of contract for supplying CO_2;
- varying the limit on the distance between the sink and source.

These sensitivities found that changing these assumptions did result in different network configurations, they did not alter the study's findings, implying the cost model is robust with respect to these assumptions.

D.1 Discount rate

Figure 32 below shows the impact of discount factor on the magnitude and shape of the marginal abatement curve. The blue curve shows the results using a discount rate of 0%, whereas the red curve shows results when the discount rate used is 10%, which is the base case. Increasing the discount rate clearly decreases the ongoing operating and maintenance costs of transport and storage. The position of gas fields relative to each other in the marginal abatement curves has not changed significantly.

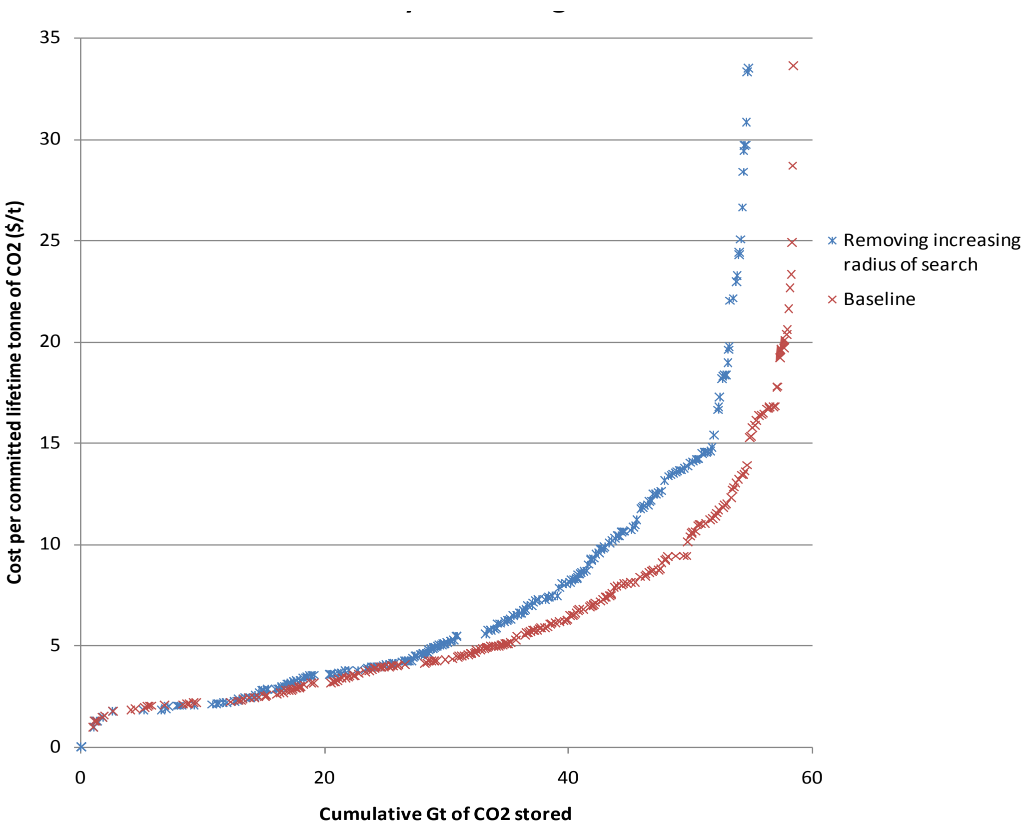
Figure 32 – Sensitivity: discount rate 0 to 10%



D.2 Restriction on distance between sink and source

The algorithm use in the network model to link sinks with sources was subject to a distance limit which increased during the period being studied. Figure 33 below shows the impact of removing the increasing radius of search imposed in the baseline model, so a limit of 1,500km is applied in all decades. For cheaper storage projects, that is those less than $5 per lifetime tonne of CO_2 transported and stored, there is little difference between the two cases. For more expensive projects, with longer pipelines, changes in the configurations of the pipelines have a greater impact on cost.

Figure 33 – Sensitivity: removing radius of search



Altering the relative weighting and limits for mt CO_2 pa, distance of sources, and contract lifetimes does influence which sources and sinks are matched in the network connection algorithm. While these factors switch the directions of pipelines between sources and sinks, there is very limited global overall additional use of sources and sinks that are not used in the baseline scenario. Regional trends were preserved for these sensitivities. Further there is little change in the total amounts and costs of CO_2 transport and storage

We have extended the analysis of the impact of varying the limit on the distance between the sink and sources through:

- doubling the limit imposed in the base case; and
- setting the limit to 3,000 km in all decades.

The distances in the base case and sensitivities for each decade are shown in Table 34 below.

Table 34 – Assumed distances in base case and sensitivities

	2011-2020	2021-2030	2031-2040	2041-2050
Baseline	250km	500 km	1,000 km	1,500 km
Double radius of search	500 km	1,000 km	2,000 km	3,000 km
3,000 km limit throughout decades	3,000 km	3,000 km	3,000 km	3,000 km

Table 35 below show the impact of varying the distance restriction on the:

- number of sources connected;
- volume of CO_2 transported and stored each year; and
- total volume of CO_2 stored.

Table 35 –Varying the restriction on the distance between sink and source

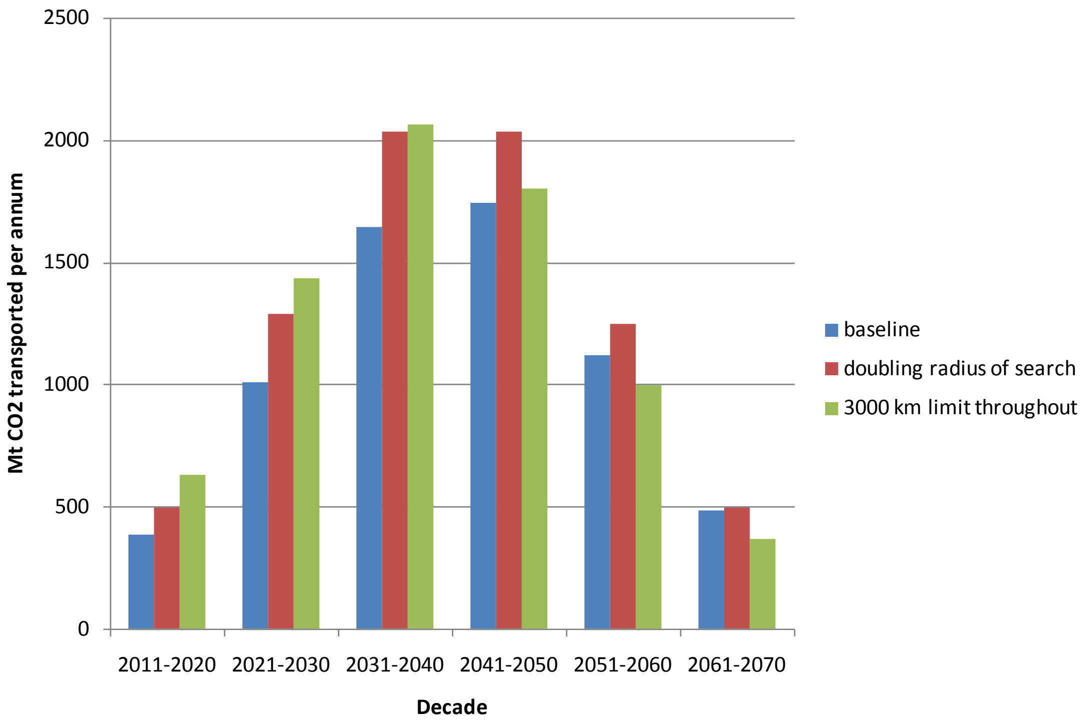
	2011-2020	2021-2030	2031-2040	2041-2050
No. sources connected				
Baseline (30 years)	119	162	163	123
Double radius of search	146	197	167	85
3,000 km limit throughout decades	167	215	173	58
Volume of CO_2 transported per year (mt)				
Baseline (30 years)	383	1,007	1,644	1,742
Double radius of search	496	1,287	2,036	2,035
3000km limit throughout decades	631	1,436	2,064	1,802
Total CO_2 stored (Gt)				
Baseline (30 years)	3.8	13.9	30.3	47.8
Double radius of search	5.0	17.8	38.2	58.5
3,000 km limit throughout decades	6.3	20.7	41.3	59.3

Table 35 indicates that the most significant impact of increasing the distance limit is:

- a greater number of sources are linked in the early years but over time the number of sources that are connected to sinks declines; and
- a larger volume of CO_2 is transported and stored.

Figure 34 overleaf graphically presents how the volume of CO_2 transported each year changes as the distance limit varies.

Figure 34 – Volume of CO_2 transported each year varying limit on distance



D.3 Contract length

This section varies the contract period between source and sink. The contract period covers the period a sink will accept CO_2 from a source, and hence determines the:

- number of sources that will connect to the sink;
- period of time required to fill the sink; and
- average capital costs that need to be recovered in each year.

This section compares the assumed contract period of 30 years in the base case with contract period of 20 and 40 years to enhance our understand of its importance.

Table 36 overleaf shows the impact of varying the contract length on:

- number of sources connected;
- volume of CO_2 transported and stored each year; and
- total volume of CO_2 stored.

Table 36 – Varying the contract length

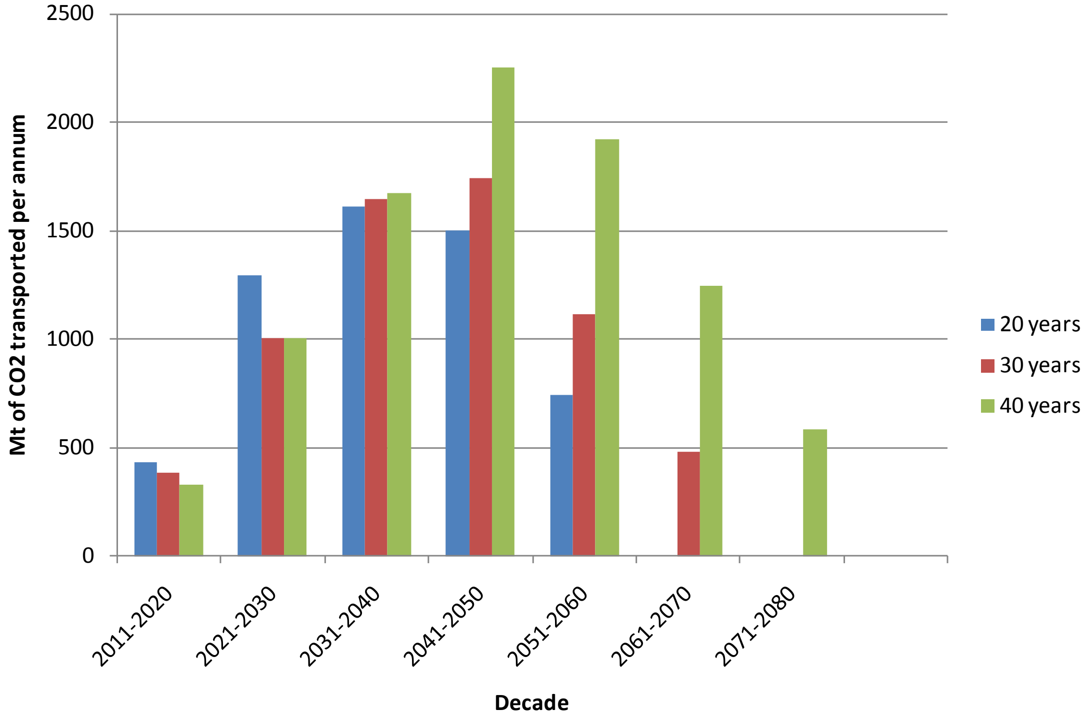
	2011-2020	2021-2030	2031-2040	2041-2050
No. sources connected				
Baseline (30 years)	119	162	163	123
20 years contract	133	195	180	121
40 years contract	105	150	149	107
Volume of CO_2 transported per year (mt)				
Baseline (30 years)	383	1,007	1,644	1,742
20 years contract	433	1,292	1,613	1,498
40 years contract	330	1,004	1,671	2,253
Total CO_2 stored (Gt)				
Baseline (30 years)	3.8	13.9	30.3	47.8
20 years contract	4.3	17.3	33.4	48.4
40 years contract	3.3	13.3	30.0	52.6

Table 36 indicates that the most significant impact of increasing the contract length is:

- the number of sources linking declines are the contract length increases; and
- a shorter contract period will initially result in higher volumes of CO_2 being transported but over time this changes so that higher volumes are transported when the contract length is longer; and
- the total volume of CO_2 transported and stored appear similar by the end of the time frame being considered.

Figure 35 graphically presents how the volume of CO_2 transported each year changes as the contract length varies.

Figure 35 – Volume of CO_2 transported each year varying contract length



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QUALITY AND DOCUMENT CONTROL

Quality control			**Report's unique identifier: 2009/087**
Role	Name	Signature	Date
Author(s):	Barry Ladbrook		4 March 2009
	Neil Smith		4 March 2009
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	Kate Harland		4 March 2009
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	Karen Kirk		4 March 2009
Approved by:	Phil Hare		4 March 2009
QC review by:	Beverly King		4 March 2009

Document control			
Version no.	Unique id.	Principal changes	Date
v1_0		Draft report	9 December 2008
V2_0		Final draft report	23 February 2009
V3_0		Final report	4 March 2009

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