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CCS Industry Build-Out Rates – Comparison with Industry Analogues

IEA GREENHOUSE GAS R&D PROGRAMME

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- Keith Burnard, IEAGHG
- Tim Dixon, IEAGHG

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The IEAGHG manager for this report was:

- Keith Burnard

The expert reviewers for this report were:

- Lamberto Eldering, Statoil
- Robin Irons, Uniper
- Theo Mitchell, CCSA
- Alastair Rennie, Consultant

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Further information or copies of the report can be obtained by contacting IEAGHG at:

IEAGHG, Pure Offices, Cheltenham Office Park
Hatherley Lane, Cheltenham,
GLOS., GL51 6SH, UK
Tel: +44 (0)1242 802911
E-mail: mail@ieaghg.org
Internet: www.ieaghg.org

CCS Industry Build-Out Rates – Comparison with Industry Analogues

Edited by Keith Burnard and Tim Dixon

IEAGHG Technical Review 2017/TR06

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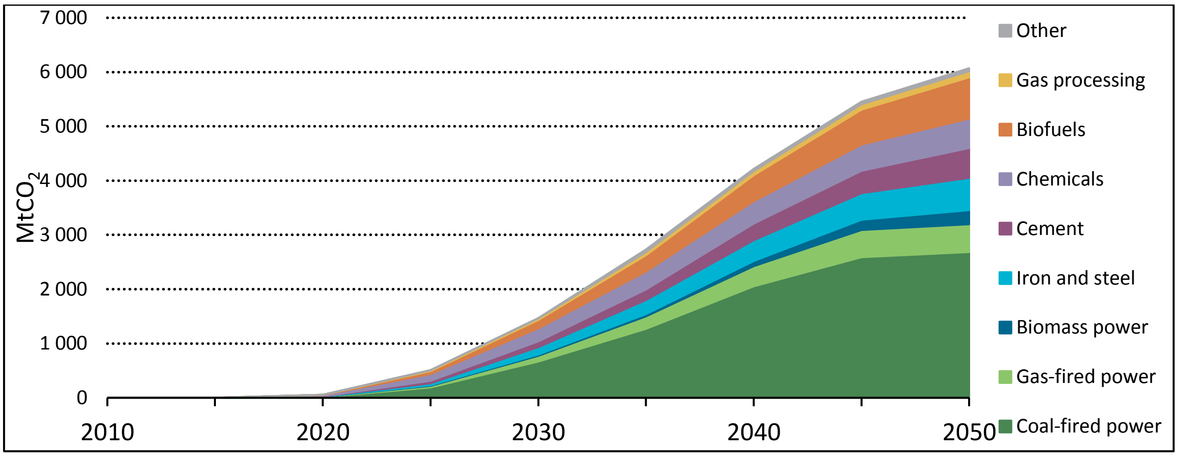
Executive Summary

Over the past decades, it has become apparent that there is no one single technological solution to solving the problem of reducing anthropogenic greenhouse gas emissions. A portfolio of low-carbon energy technologies needs to be deployed in parallel. Most climate scenarios targeting 2°C or well below 2°C confirm that carbon capture and storage (CCS) is an essential element in this portfolio as it significantly increases the probability of reaching the emission reductions required and at least cost. CCS roadmaps have established that widespread deployment of CCS is needed to deliver this contribution – which includes decarbonisation of a variety of sectors with large emissions, as well as deploying negative emissions technologies such as bio-energy with CCS (BECCS).

The urgency of accelerating the deployment of CCS is increasing as time passes and ambitions grow firmer through developments such as the Paris Agreement. Although CCS R&D has progressed, with medium-scale pilot projects proving that CCS is feasible and technically ready for deployment, the pace of large-scale deployment of CCS has been slow, with only some fifteen large-scale facilities in operation today. However, this slow pace is not due to the technical or physical limitations of building out the industry; a major barrier has been the absence of market incentives, compounded by the fact that capture projects need access to transport and storage infrastructures, the development of which takes time.

The question has been raised whether the CCS industry can build out at the rates projected in CCS roadmaps. This study compares the anticipated CCS build-out rates with those achieved in other sectors, where comparable technologies in those sectors have been used as analogues. In particular, it addresses whether the build-out rates for CCS, as depicted in Figure ES.1, are tenable, i.e. whether the claimed build out is possible once the programme is up and underway. It does not attempt to address the timing of when the build-out would begin or, more particularly, the veracity of the timing of the start of build-out as depicted in Figure ES.1.



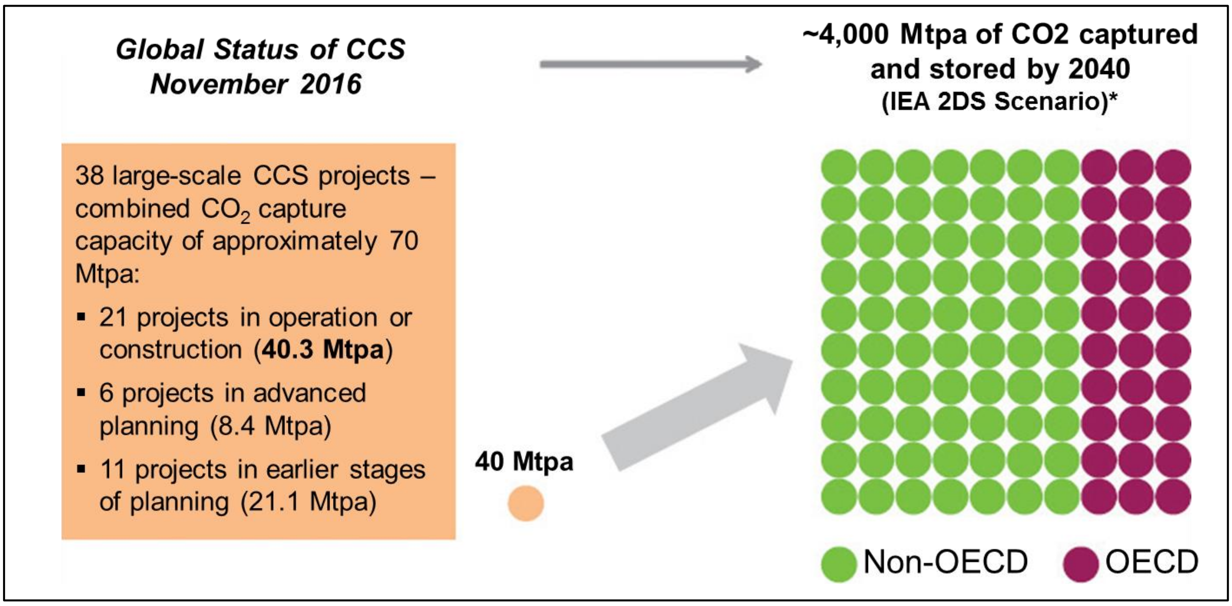
Source: Derived from *Energy Technology Perspectives 2016 (IEA, 2016)*.

Figure ES.1: Projected CO_2 capture from CCS to 2050

The study finds that the rate of build-out in industry analogues has been comparable to the rates now being anticipated for CCS. Considering these analogies, it can be seen that once sufficiently strong incentives for a technology are established, industry can achieve the rapid build-out rates required for the projected scale of deployment. This suggests that CCS development, while requiring substantial growth, may not be constrained by physical limitations in supply chain and industry build-out. However, substantial efforts would be required from both the public and the private sectors to deliver and maintain the anticipated build-out rates over the coming decades. This includes strong market incentives, stable policy commitment, government leadership and public support.

While CCS build-out will take a large effort, comparable to that made in the natural gas industry, it has the potential to drive growth creating comparable economic activity and employment to the natural gas industry.

CCS roadmaps show a steep curve for CCS industry build-out, with the ambition of achieving annual storage rates of over 5.5 billion tonnes of CO_2 per annum, some thirty years after full commitment (by 2050, according to Figure ES.1). It represents the significant task of starting up a large number of facilities and associated industry supply chain within just a few decades. This is a considerable rate of increase, given that, in 2016, the global operating capture and storage capacity was 40 million tonnes per annum (Mtpa). As signified in Figure ES.2, this would require an increase of two orders of magnitude over two decades – of which 70% would be in non-OECD countries. Over the next 2 to 3 decades, it is estimated that the CCS industry will achieve a build-out rate that adds 150 – 300 million tonnes (Mt) of CO_2 capacity each year. This estimate is based on taking a simple average of the CCS capacity targets of 4 billion tonnes captured and stored per annum after 2 decades and 6 billion tonnes after 3 (as shown for 2040 and 2050, respectively, in Figure ES.1).



Source: Derived from data underpinning *Energy Technology Perspectives 2016 (IEA, 2016)*.

Figure ES.2: A significant increase in CCS capacity is required in the next decades

On such a basis, the associated requirements for build-out rates of individual CCS items **per year** can be estimated as listed in Table ES.1.

No. items added **per year**	Individual CCS chain elements
75-150	Commissioning of new capture facilities
75-150	Number of ~20 MW CO_2 compressors
4 500-12 000	km CO_2 pipeline
15-30	Mtpa CO_2 ships (assuming 10% of CO_2 in shipping)
30-60	Storage sites developed
150-300	Million tonnes CO_2 stored
300-1 200	New wells drilled per annum
40-100	Drilling rigs deployed per annum
60-120	Platforms/wellpads installed

Table ES.1. Build-out requirements of individual CCS items of a CCS industry for a yearly additional 150-300 Mtpa CO_2

In this report, these requirements are considered and compared with analogues from other industry sectors. It is concluded that comparable build-out rates had been realised under conditions where strong incentives, appropriate regulation and market pull were in place. While it is recognised that analogies have limitations, it has been shown to be tenable technically that the anticipated CCS build-out rates could be realised in a supporting environment.

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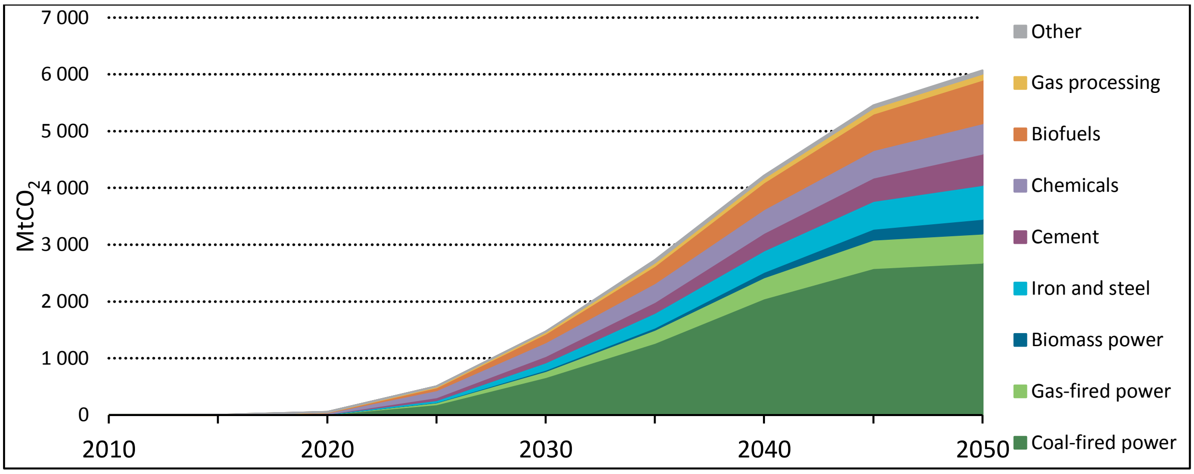
1. Introduction

Over the past decades, it has become apparent that there is no one single technological solution to solving the problem of reducing anthropogenic greenhouse gas emissions. A portfolio of low-carbon energy technologies needs to be deployed in parallel. Most climate scenarios[1] targeting 2°C or well below 2°C confirm that carbon capture and storage (CCS) is an essential element in this portfolio as it significantly increases the probability of reaching the emission reductions required and at least cost. CCS roadmaps clearly demonstrate the widespread deployment of CCS needed to deliver this contribution – which includes decarbonisation of a variety of sectors with large emissions, as well as deploying negative emissions technologies such as bio-energy with CCS (BECCS).

The urgency of accelerating the deployment of CCS is increasing as time passes and ambitions grow firmer through developments such as the Paris Agreement. Although CCS R&D has progressed, with medium-scale pilot projects proving that CCS is feasible and technically ready for deployment, the pace of large-scale deployment of CCS has been slow, with only some fifteen large-scale facilities in operation today. However, this slow pace is not due to the technical or physical limitations of building out the industry; a major barrier has been the absence of market incentives, compounded by the fact that capture projects need access to transport and storage infrastructures, the development of which takes time.

The question has been raised whether the CCS industry can build out at the rates projected in CCS roadmaps. This study compares the anticipated CCS build-out rates with those achieved in other sectors, where the build-out of comparable technologies in those sectors have been used as analogues. In particular, it addresses whether the build-out rates for CCS, as depicted in Figure 1.1, are tenable, i.e. whether the claimed build-out is possible once the programme is up and underway. It does not attempt to address the timing of when the build-out would begin or, more particularly, the veracity of the timing of the start of build-out as depicted in Figure 1.1.



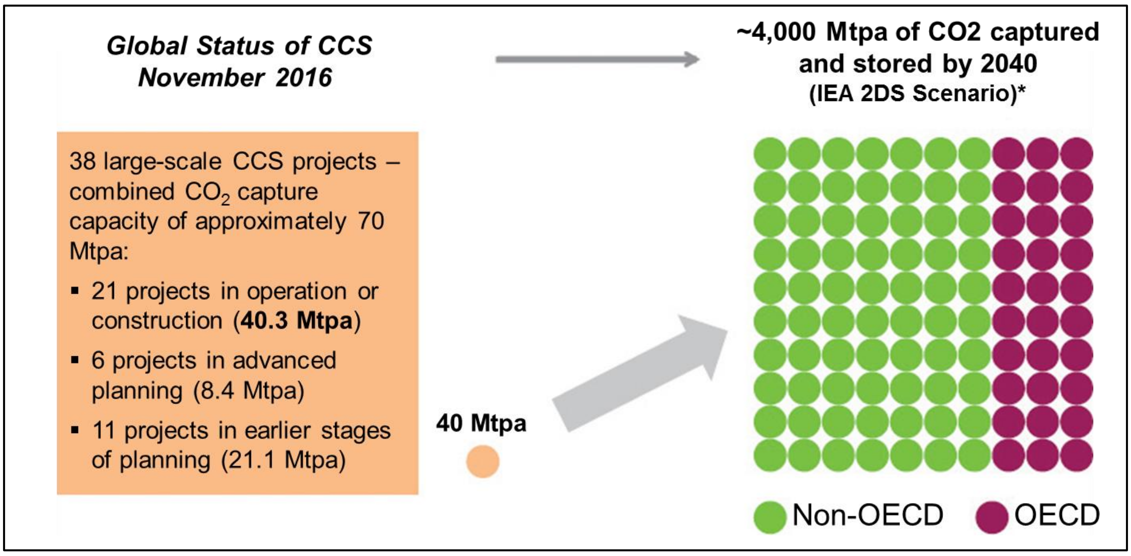
Source: Derived from *Energy Technology Perspectives 2016 (IEA, 2016)*.

Figure 1.1: Projected CO_2 capture from CCS to 2050

[1] CCS projections addressed in this document refer to projections reported in the IEA's *Energy Technology Perspectives 2016* publication (IEA, 2016), where a portfolio of technologies are deployed to reduce emissions from those projected in the IEA's 6DS to those more consistent with a 2°C increase in the global average temperature).

The study compares the rate of build-out in industry analogues to the rates now being anticipated for CCS. Assuming sufficiently strong incentives for the technology are established, the analogues can indicate whether the growth of CCS is likely to be constrained by physical limitations in the supply chain. It is clear that, if successful, a CCS industry has the potential to drive growth creating comparable economic activity and employment to the natural gas industry.

CCS roadmaps show a steep curve for CCS industry build-out, with the ambition of achieving annual storage rates of over 5.5 billion tonnes of CO_2 per annum, some thirty years after full commitment (by 2050, according to Figure 1.1). It represents the significant task of starting up a large number of facilities and associated industry supply chain within just a few decades. This is a considerable rate of increase given that, in 2016, the global operating capture and storage capacity was 40 million tonnes per annum (Mtpa). This would require an increase of two orders of magnitude over two decades (Figure 1.2) – of which 70% would be in non-OECD countries. Over the next 2 to 3 decades, it is estimated that the CCS industry will achieve a build-out rate that adds 150 – 300 million tonnes (Mt) CO_2 capacity each year. This estimate is based on taking a simple average of the CCS capacity targets of 4 billion tonnes captured and stored per annum after 2 decades and 6 billion tonnes after 3 (as shown for 2040 and 2050, respectively, in Figure 1.1).



Source: Derived from data underpinning *Energy Technology Perspectives 2016 (IEA, 2016)*.

Figure 1.2: A significant increase in CCS capacity is required in the next decades

On the basis of the expansion in CCS deployment projected in Figures 1.1 and 1.2, the associated requirements for build-out rates of individual CCS items **per year** can be estimated. These requirements are listed in Table 1.1.

No. items added **per year**	Individual CCS chain elements	Addressed in Section:
75-150	Commissioning of new capture facilities	2.2
75-150	Number of ~20 MW CO_2 compressors	2.3

4 500-12 000	km CO_2 pipeline	3.1
15-30	Mtpa CO_2 ships (assuming 10% of CO_2 in shipping)	3.2
30-60	Storage sites developed	4.1
300-300	Million tonnes CO_2 stored	4.1
150-1 200	New wells drilled per annum	4.3
40-100	Drilling rigs deployed per annum	4.3
60-120	Platforms/wellpads installed	4.3

Table 1.1: Build-out requirements of individual CCS items of a CCS industry for a yearly additional 150-300 Mtpa CO_2[2]

In this report, the annual build-out requirements are considered and compared with analogues from other industry sectors to explore the viability of achieving such rates of physical build-out.

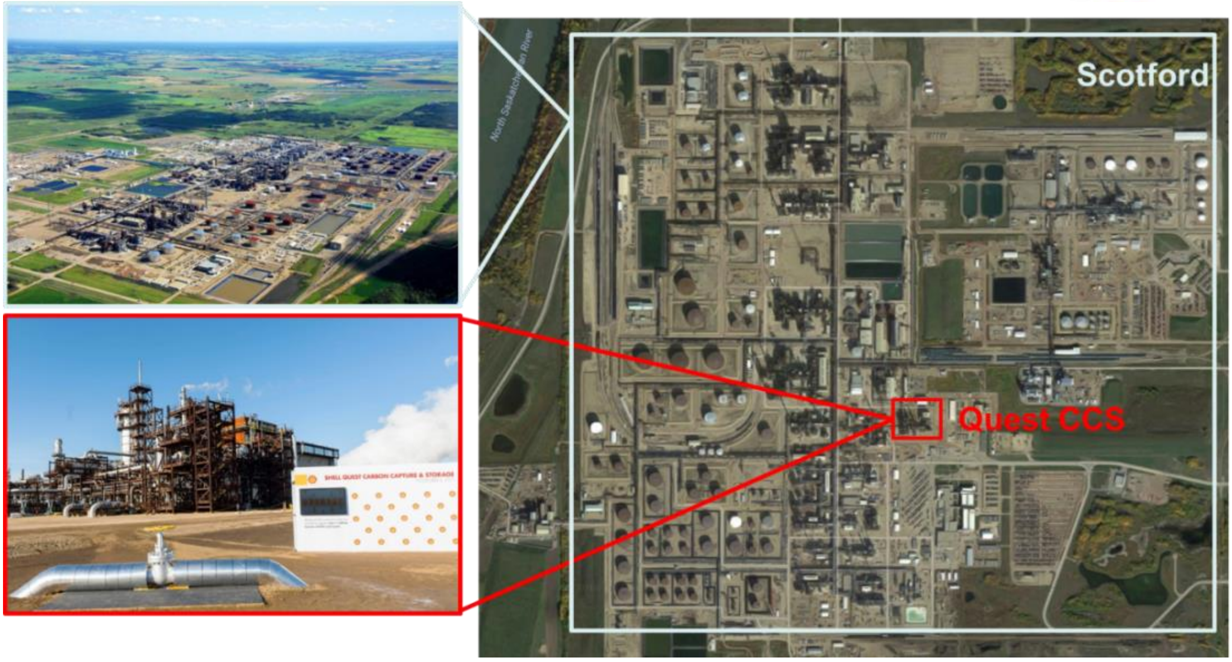
2. Capture facilities

2.1 In context

CO_2 capture technology is technically available. It has successfully been applied in capture units at assets operating globally. Capture facilities have comparable complexity to process units that are routinely installed in industry. Most commonly, there is extensive experience in solvent-based capture in the oil and gas industry, from decades of use in gas processing applications. The capture plants require a design skill set that is found within the oil and gas industry, and can be built up on the basis of existing experience.

Quest CCS is an example of a CO_2 capture facility, which injects 1 Mtpa of CO_2 from the Scotford Upgrader in Alberta, Canada. As illustrated in Figure 2.1, the capture unit is one of many process units at the Scotford complex (which comprises the Scotford Upgrader, refinery and chemicals plant). To put this further into perspective, the Scotford Upgrader has a capacity of 255 kbbl/d (ca. 40 500 m^3/d) and the refinery processes 100 kbbl/d (ca. 16 000 m^3/d) – against Alberta’s total upgrading and refining capacity of 1 788 kbbl/d (ca. 284 000 m^3/d) (Alberta Government, 2015). Thus Quest CCS is a relatively small application considering these scales of industrial activity.

[2] Assumptions :1-4 Mtpa capture facilities, 2 Mtpa CO_2 compressors, storage project 5-10 Mtpa storage (100-200 Mt total storage at site), 1-2 wellpads/platforms per project, injection wells 0.25-1 Mtpa



Sources: Images from Google Maps and Shell

Figure 2.1: Quest CCS in the context of the Scotford complex: a size comparison

Another example is Boundary Dam CCS plant, where 1 Mtpa of CO_2 is captured from Production Unit 3 of the Boundary Dam Coal-Fired Power Station. The refurbished unit, which includes the application of CCS, enables a lifetime extension of the unit consistent with Canada’s emissions performance standard for coal-fired power plants, has a capacity of 120 MW.

In contrast to the Scotford complex, where Figure 2.1 shows the scale of the Quest CCS compared with other on-site industrial activities, Figure 2.2 illustrates the substantial size of the first coal CCS unit at Boundary Dam compared to the power plant, which includes all the coal-fired production units. Boundary Dam Power Station has a capacity of 824 MW, against a total fossil fuel-based generating capacity of over 3 000 MW in Saskatchewan, Canada (Halliday, 2013). Figure 2.2 also illustrates how Boundary Dam sits within the scale of Saskatchewan’s other power generating activities (fossil and non-fossil).

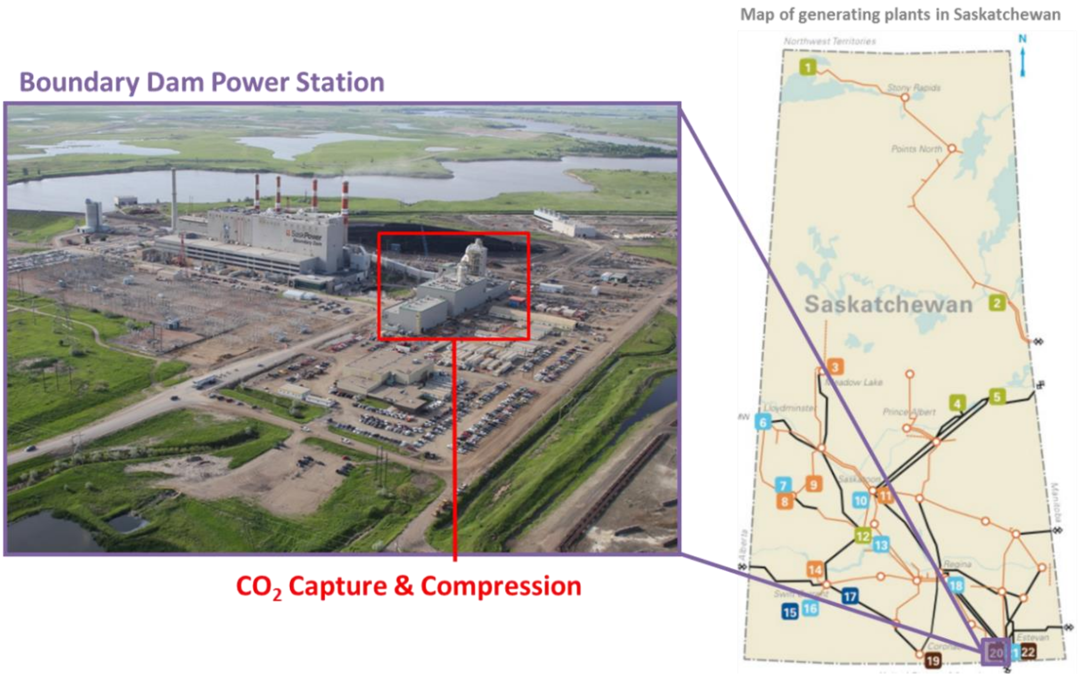


Figure 2.2: Size of Boundary Dam capture plant size compared with Boundary Dam Power Station (where CO2 is captured from one of four boilers at the station) and in the context of power generation in Saskatchewan (Halliday, 2013)

This view can be expanded further to visualise the scale of power generation: Figure 2.3 shows a map of power plant capacity across the United States where, in 2015, 64% of US power was generated by coal and natural gas (Muyskens, Keating, & Granados, 2015); coal-fired and gas-fired power plants are shown in black and orange, respectively. There are 511 coal-fired and 1 740 natural gas-fired power generation plants across the United States.

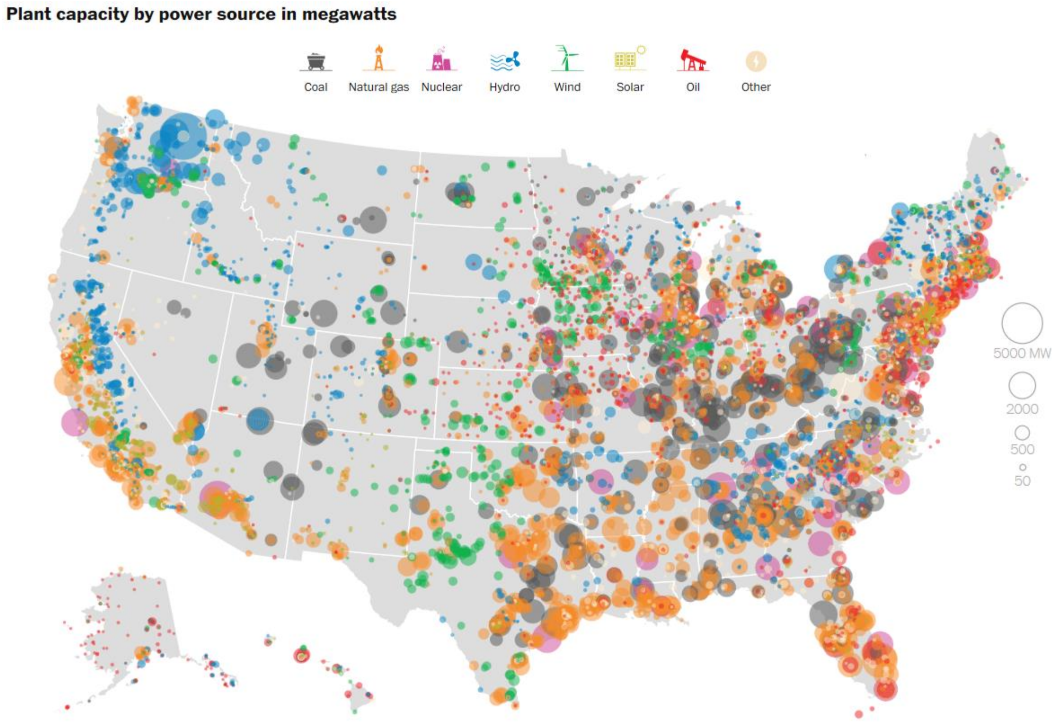


Figure 2.3: US power generation plants (Muyskens, Keating, & Granados, 2015)

2.2 Capture plants

As indicated in Table 1.1, the build-out requirement of capture plants sees the commissioning of around. **75-150 large-scale units per annum** (considering units capturing between 1 and 4 Mt CO_2 per annum). This averages out at a need for 2 to 3 new capture units per week. The power sector was considered as the analogue for the technical feasibility of such build-out rates.

Looking specifically at combined cycle gas turbine (CCGT) power plants globally, as well as regionally in Europe and in the USA, it can be seen in Figure 2.4 that in recent history, global peak rate additions comparable to the suggested build-out requirement have been achieved in CCGT alone (up to 119 in one year). This includes the commissioning of new power plants of different capacities, without considering new units on existing plants; the average electrical capacity of which was around 350 MW.

It is noted that, while technically, global CCGT build-out rates of **60-120 plants/year** were achievable, the actual rate is strongly dependent on the right environment being in place to build and operate these plants (which could be enabled through a combination of drivers in policy and regulation).

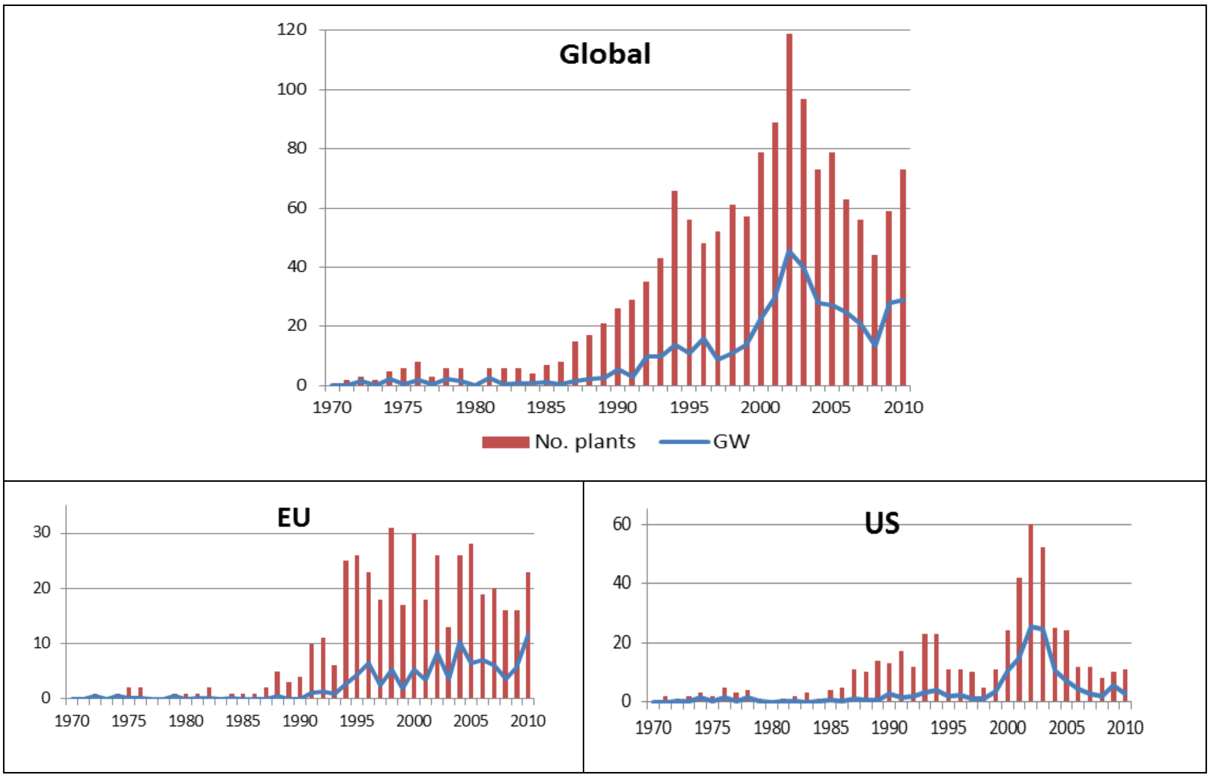
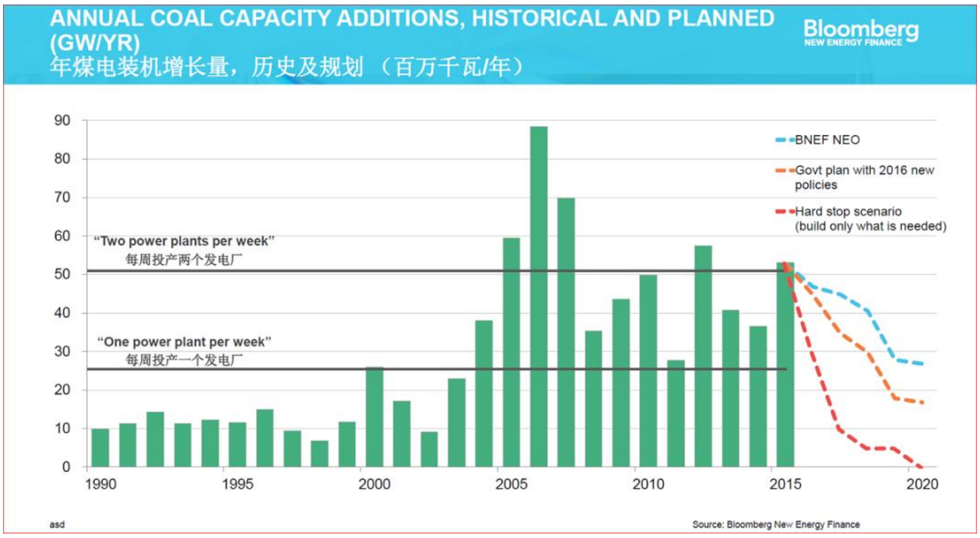


Figure 2.4: Start-up of gas CCGT power plants globally, in the EU and in the United States (Platts, 2013)

At the same time when this impressive growth happened in the natural gas power industry, power capacity was added in large quantities via other types of facilities too, such as coal power plants or facilities powered using renewable energies. Another example of substantial power capacity addition has been taking place in China, where an average build-out of **two new coal-fired power plants per week** has been achieved for several years, as shown in Figure 2.5.



Note: BNEF NEO refers to the New Energy Outlook by Bloomberg New Energy Finance.

Figure 2.5: Annual coal capacity additions (in GW/year) in China (Landberg, 2016)

2.3 Large-scale CO_2 compressors

Another key part of the CCS chain is CO_2 compression at the back end of the capture plant. Wide scale deployment of CCS would require a notable increase in the delivery of large-scale compressor units to bring captured CO_2 to high pressures (100 – 200 bar) and transport it. Assuming one large compressor per capture facility, the required build-out would approximate **75 – 150 compressors per annum** (of about 20 MW each).

There are several large compressor manufacturers that can deliver such equipment across the globe. A previous IEAGHG study (IEAGHG, 2012) referenced six major compressor manufacturers as a selection, while noting that there are other suppliers who could enter the CO_2 compression market. Considering six manufacturers only, each would see the delivery of between 12 and 25 compressors per annum.

The current size of the compressor industry is significant, including the natural gas compressor market. For example, large-scale compression is common in the LNG industry, which has 92 LNG trains operating globally, with another 33 trains under construction for 2016 – 2019.

Experts in the industry confirmed that some of the major compressor suppliers are already delivering in the order of 20 large units per annum each in different applications; and are confident that increasing compressor manufacturing to 100 units per annum, or even more, is feasible. Production capacity may require time to be built or reconfigured in the early years; however, this supports the contention that the delivery of compressors at the assumed rates will not be limiting to the CCS chain build-out.

3. Transport

Wide-scale deployment of CCS will require integrated transport systems to carry the CO_2 from the source or capture locations to the storage sites. It is envisioned that this would be achieved through a combination of transmission pipelines, in the majority, with a modest level of CO_2 transport in ships & barges. The CO_2 transportation method would depend on the specifics of the source and storage site locations. Ship transport would be well suited to situations of e.g.

uncertain demand and smaller masses, where construction of a pipeline would be sub-economic).

For illustration purposes, the following discussion applies an estimated split to the transport of CO_2. It is assumed that 10% of the CO_2 projected for storage in the 2DS (IEA, 2016) could be transported via liquefied CO_2 vessels (barges or ships) and the remainder via pipeline networks.

3.1 Pipelines

The build-out of a CO_2 pipeline network of sufficient capacity is addressed first.

The physical construction of a dense phase CO_2 transmission pipeline and a high pressure natural gas transmission pipeline is almost identical. As a result, the build-out rate of historic natural gas transportation networks provides a good analogy for the construction of future CO_2 transportation networks. Similar pipe diameter sizes are used, pressures normally in the conventional range of 100-200 bar, and no general requirement for exotic metallurgy provided that water is removed prior to transport (it is probably that other impurities will also be removed but this requirement is driven more by the injection well metallurgy, where water is present in the subsurface, than by the pipeline metallurgy). Onshore CO_2 pipelines differ in one aspect, with a requirement for a certain level of toughness in the steel or deployment of crack arrestors to prevent the spread of running ductile fractures. In some cases, former natural gas pipelines would already be directly suitable and have the potential to be converted to transport CO_2, e.g. as was selected for the proposed UK North Sea Peterhead CCS project (Shell U.K. Limited, 2015). Both natural gas and CO_2 pipelines would also require similar manpower resources and time for design, planning and installation; there would be some differences in risk assessment, given the different natures of the fluids.

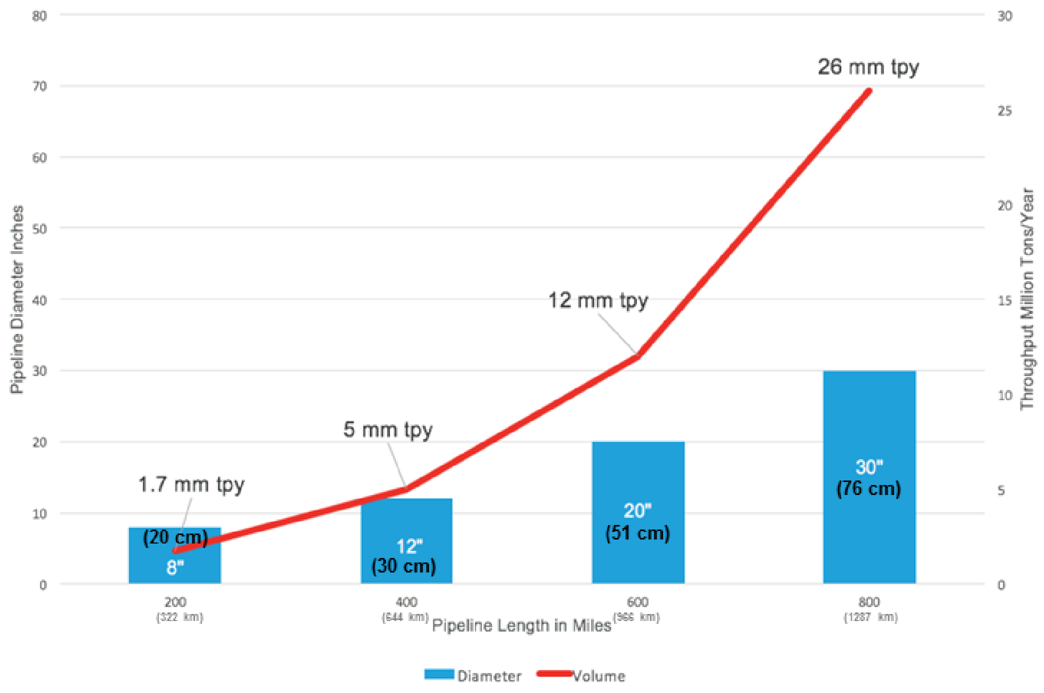
The topology of the networks for transport of natural gas, and CO_2 for storage are almost mirror images. Natural gas is transported from geological formations at producing field development sites to industrial hubs for processing and use (a fraction goes to gas storage for use during periods of peak demand), while CO_2 needs to be transported in the reverse direction, i.e. from industrial hubs to storage injection sites, which occur in geological formations similar to those that have contained hydrocarbons for millions of years.

It is difficult to make a robust estimate of the required CO_2 transportation pipelines without explicitly mapping source and sink locations. The transport distances required are likely to vary by region, along with population density and the overall scale of the landmass. Hence larger transport distances might be expected in continental Europe to connect CO_2 generating regions where the geology or political environment is not suitable for storage with sedimentary basins that are suitable for storage; shorter transport distances might be expected in the UK or Australia, where industrial regions are more likely to be within reach of the coast, and significant storage potential has been proposed in near offshore areas (Bentham et al, 2014) (Carbon Storage Taskforce, 2009). The majority (95%) of the largest CO_2 point sources in the United States lie within 80 km (50 miles) of a potential storage reservoir (Dooley et al, 2006).

The US CO_2-EOR Deployment Work Group released a white paper emphasising the need for CO_2 pipeline development in the United States (State CO2-EOR Deployment Work Group, 2017). This document included an estimate of the maximum pipeline length by pipe diameter to meet economic targets (cost per tonne transported) – the longer the distance, the larger the throughput required to achieve the lowest unit cost.

An initial estimate is made here (by analogy to natural gas gathering and transmission networks) for the average pipeline construction length required to connect CO_2 captured at industrial CO_2 gathering hubs to developed storage sites. This estimate does not include the transport of captured CO_2 from individual industrial sites to gathering hubs, which might be achieved in part using a separate low pressure transport system to capitalise on economic efficiencies of centralised compression and conditioning facilities at the industrial CO_2 gathering hub. Considering the pipeline size, capacity and maximum length data given in Figure 3.1 (State CO2-EOR Deployment Work Group, 2017), we have estimated the following transport cluster[3];

- Five geological storage sites taking 5 Mtpa (see Storage section) receive CO_2 from a local distribution cluster to which each is connected by 100 km of 30 cm (12") pipeline (alternatively two geological storage sites taking 5 Mtpa of CO_2 could be replaced by one storing 10 Mtpa connected by a 200 km, 51 cm (20") pipeline)[4].
- The local distribution cluster receives 25 Mt of captured CO_2 a year from the industrial gathering hub 250-500 km away. This is transported via a 76 cm (30") pipeline.



Note: The longer you build the pipe, the larger (higher capacity) it must be to make sense economically. [Field units are employed in the figure: mm tpy = Mtpy.]

Figure 3-1: Maximum length per pipeline size needed to drive down transport costs to $10 per tonne (State CO2-EOR Deployment Work Group, 2017).

The number of storage sites in a cluster, individual transport distances and pipeline diameters will vary; this 'average distribution cluster' is proposed as an initial estimate only, the scale of which may be compared visually in Figure 3.2 with the area of the United States. 20% of the 2DS target (IEA, 2016) of 5.5 billion tonnes per annum storage could be met with the development of 250 storage sites, each injecting 5 Mt CO_2 per annum; this would approximate to 44 of the 25 Mtpa pipeline cluster networks described above. This is sufficient to store

[3] This is one scenario and can be altered to adjust to specific conditions, however, adjusting the estimates up or down within reasonable constraints does not fundamentally alter the answer.

[4] 100 km to individual storage sites based on approximate 55 x 55 km (50 m net storage reservoir thickness, 20% porosity, 1% Ef (storage efficiency factor); CO_2 density at reservoir conditions 700 kg/m^3; ca. 200 Mt capacity).

approximately half of the CO_2 emissions from electricity generated annually in the United States.[5]

For more isolated industrial centres, with no conveniently accessible storage locations due to an unfavourable geological or political environment, the use of additional transcontinental pipelines (or transport by sea) may be required.

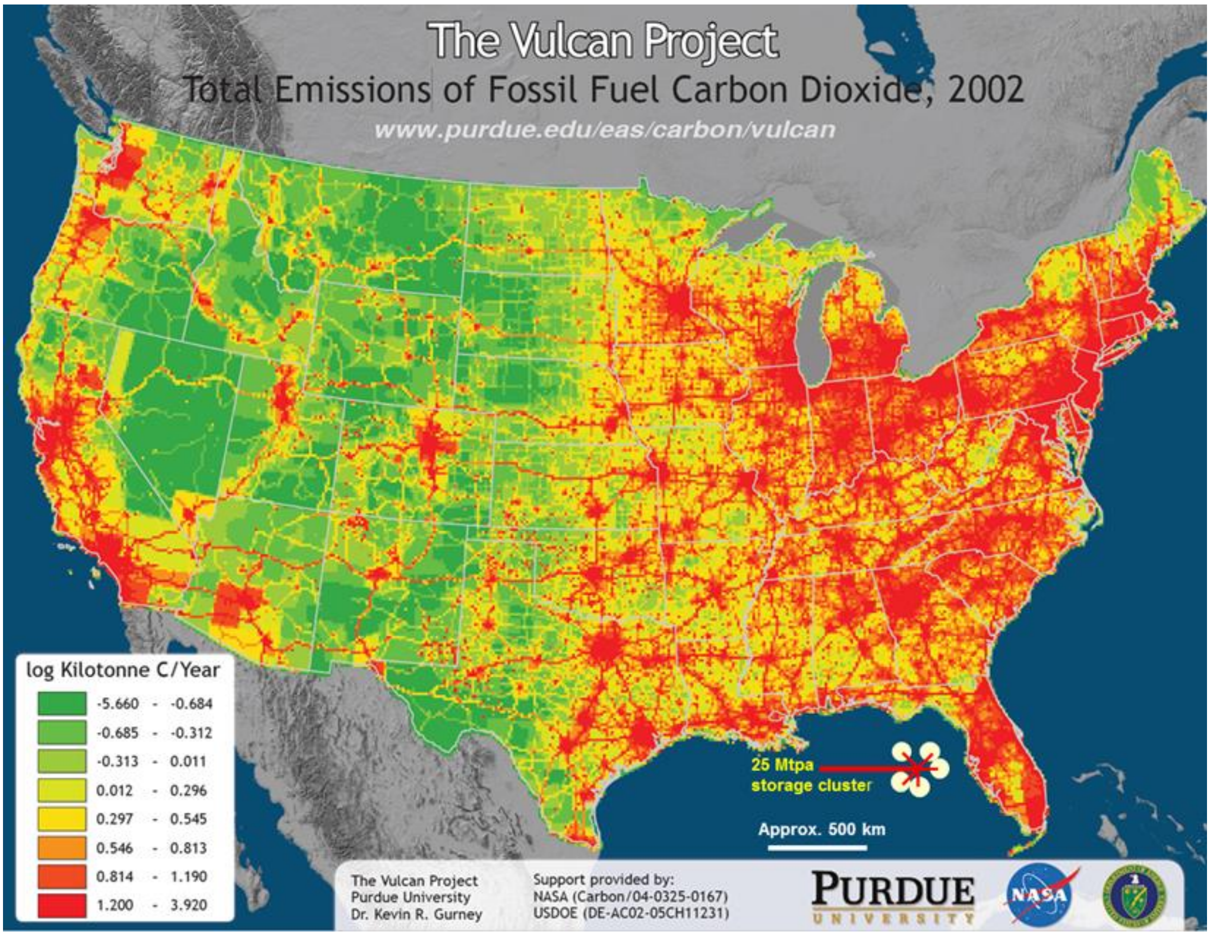


Figure 3.2: Map of 2002 US emissions (Vulcan project) with schematic diagram of 25 Mt storage pipeline cluster (with 500 km x 76 cm trunk pipeline)

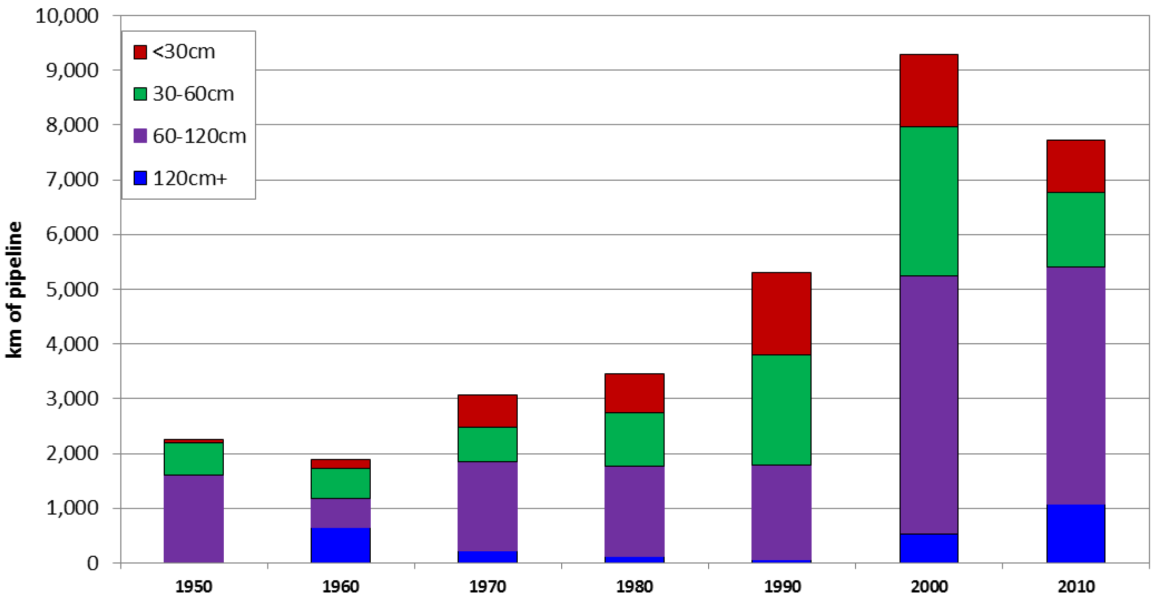
This predicts a requirement for construction of 750 to 1 000 km of pipeline per storage cluster (25 Mt CO_2 stored per annum per cluster as described above); resulting in construction of **4 500 to 12 000 km of new pipeline per year**, in line with an annual average increase of transport capacity of 150 to 300 Mtpa (approximately 30 to 60 projects developed annually; see the discussion below on storage build-out). The 2009 IEA technology roadmap for carbon storage generated a similarly high case estimate for pipeline construction based on the average distance between CO_2 source and storage site and the level of optimisation achieved in developing transport systems (IEA, 2009).

Wood Mackenzie collates historic and planned global pipeline construction data in their Upstream Data Tool (Wood Mackenzie, Q4 2016). These data indicate that in the last decade the natural gas pipeline construction industry has maintained a build rate of over 5 000 km of pipeline installed annually, with recent years seeing around 8 000 km/year (Figure 3.3). Over

[5] CO_2 emissions from power generation are likely to reduce with increased use of renewable generation sources; however, there are significant CO_2 emissions that could be captured from other industrial processes. Average CO_2 emissions from US electricity generation (over the period 2005-2015) was 2.3 Gtpa (U.S. Energy Information Administration (EIA), 2016).

twenty years (comparing 1980-1989 with 2000-2009) the global pipeline capacity more than doubled. Hence, given appropriate incentives, it is reasonable that the industry could grow to accommodate construction rates as high as **12 000 km/year**.

Incentive schemes, as outlined by the State CO2-EOR Deployment Work Group (2017), could facilitate early pipeline construction and industry build-out. In addition, early build-out might focus on regions where recent rates of pipeline construction have been high (giving experienced workforce), and are declining (making the workforce available). Build-out in other regions, where initial resource constraints may apply due either to lack of equipment or workforce, could grow more slowly to begin with.



Source: Pipeline construction data from the Wood Mackenzie Upstream Data Tool **(Wood Mackenzie, Q4 2016)**. The plot shows the average length of pipeline coming on-stream each year binned into pipeline diameter size categories. Wood Mackenzie data cut 4th November 2016 (Q4). Downloaded for plot December 2016. [*Note that the Upstream Data Tool includes some inevitable data gaps due to unavailability; for this reason, 33% of the total constructed pipeline length included in the database could not be plotted due to unavailable on-stream dates. The database was filtered to include standalone and child Group data only to prevent double counting of pipeline in regional systems (e.g. North Sea CATS system); and includes only pipelines assigned product type 'gas'*.]

Figure 3.3: Average global pipeline length brought on stream per year: by decade and diameter (gas only)

Natural gas pipeline systems have grown organically, where additions to the network were determined by each new gas discovery or other natural resource or human development factors. Natural gas pipelines needed to be built quickly and developed at short notice to monetise these discoveries. If governments view a CO_2 transport pipeline network, in support of CO_2 storage (and utilisation), as a strategic national infrastructure with incentives for co-operative construction, then greater efficiency might be expected in terms of resources (materials and manpower), routing, construction time and cost compared with the historic construction of natural gas pipeline networks.

3.2 Shipping

This analysis estimates that 10% of the mass of CO_2 to be transported for storage might require transportation via sea (or rivers and canals). The assumption is based on the approximate proportion of global natural gas production that is transported currently via LNG carrier (BP, 2016).

The pipeline build-out assessment indicated that sufficient transportation capacity could feasibly be constructed to carry the entire CO_2 tonnage projected in the 2DS; additional transport options using ships add flexibility and mass-contingency to global CCS networks. While LNG carriers often take the form of supercarriers travelling very long distances, geology means that it is less likely that CO_2 would need to be moved such long distances, so the ships would be expected to be smaller. Transportation by ship (or barge) would provide a more flexible solution for smaller masses, middle distances or variable demand and destinations.

The transport of CO_2 by ship could be achieved by cooling the CO_2 to a liquefied state (minimizing volume) for transportation on specially constructed 'liquefied CO_2' vessels, analogous to those used today to transport liquefied natural gas (LNG) or liquefied petroleum gas (LPG). The capacity and construction of LNG vessels is taken as the analogue for large scale ship construction and build-out of point-to-point transport capacity, where the substantial differences in ship design is noted.

Component	Pressure kPa	Temperature °C	Density kg/m^3	LNG to CO_2 mass conversion[6]
LNG	101	-162	456	-
CO_2 [low P]	600	-50	1 155	2.5
CO_2 [mid P]	1 500	-25	1 054	2.3
CO_2 [high P]	4 500	10	861	1.9

Note: LNG density and transport conditions from US DOE (US DOE, 2005). CO_2 density from NIST liquid density at given temperature (US DOE, n.d.).

Table 3.1: Typical LNG storage conditions (pressure, temperature, density) and potential range of CO_2 transport vessel design conditions (Gassnova, 2016)

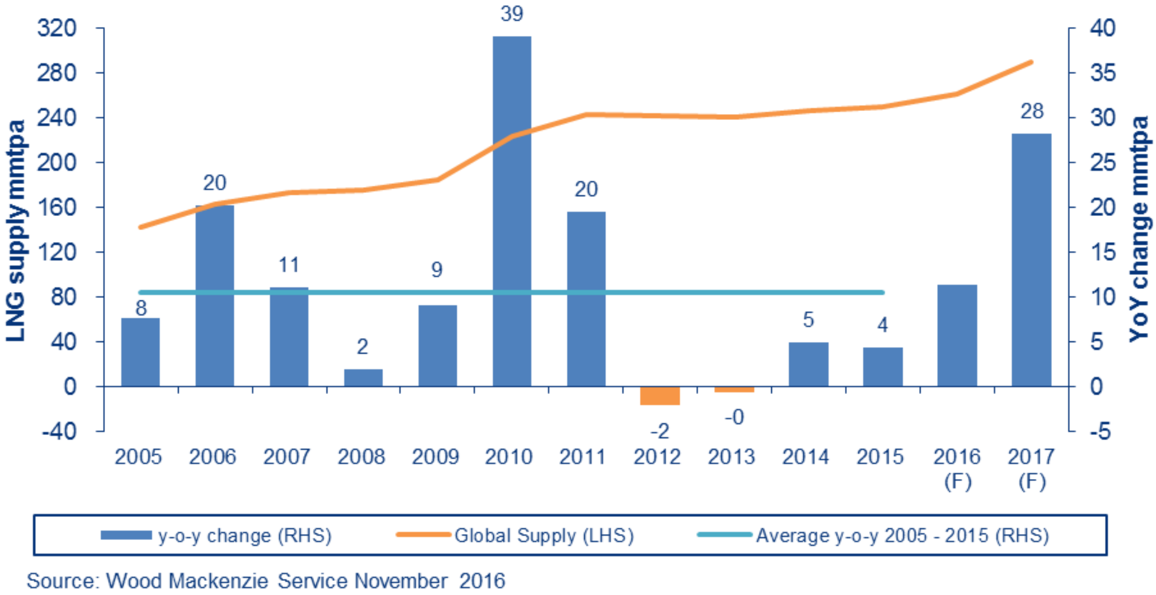
Prototype designs for such vessels have been published (Gassnova, 2016). The liquefied CO_2 vessels would run at a higher temperature and pressure than a typical LNG vessel (-50°C to 10°C versus -160°C) due to the different pressure / volume / temperature (PVT) properties of methane (majority component of LNG) versus CO_2 (see Table 3.1).

The thermodynamic (PVT) properties of methane and CO_2 at the appropriate vessel conditions are used to convert historic LNG transport capacity to equivalent CO_2 transport capacity (given the same vessel size). For every 1 Mtpa of LNG that can be transported, the equivalent vessel could transport between 1.8 and 2.5 Mtpa of CO_2 depending on the vessel design. A mass to mass conversion factor of two is applied in this analysis.

To transport 10% of the 2050 IEA CO_2 capture and storage target via liquefied CO_2 vessels, requires a year-on-year increase of transport capacity of 15-30 Mtpa. Historic LNG

[6] Mass of CO_2 (Mt) that can be transported in the equivalent volume as 1 Mt of LNG given the various vessel conditions (pressure and temperature). Gassnova (Gassnova, 2016) have proposed three liquefied CO_2 vessel designs.

transportation data (Wood Mackenzie, 2016), Figure 3.4, shows that the mass of LNG transported has increased over the ten years reported (from 2005 to 2015) at an average rate of 10 Mtpa of LNG (equivalent transport capacity to 20 Mtpa of CO_2). The largest increase was recorded in 2010, when an additional 39 Mtpa LNG was transported (equivalent to 78 Mtpa of liquefied CO_2).



Note: Plot reproduced from Wood Mackenzie LNG report (Wood Mackenzie, 2016). For the majority of the period plotted (2005 to 2015: historic data) the global transport of LNG has increased (average 10 Mtpa LNG), indicating a general increase in transport capacity. Note field units: mmtpa = million tonnes per annum (Mtpa).

Figure 3.4: Total mass of LNG transported per year and the year-on-year change.

In 2010, the LNG carrier fleet consisted of 360 vessels at a combined capacity of 53 million m^3 (24 Mt), transporting around 224 Mtpa. The capacity of individual LNG carrier vessels has increased over time (with a current average of 160 000 – 170 000 m^3, equivalent to ca. 75 000 tonnes LNG) and, in the years between 2005 and 2010, a large number of vessels was added to the fleet, Figure 3.5. With a maximum addition of 47 vessels in 2008, equivalent to around 3.5 Mt capacity (International Gas Union, 2010), a fast build-out of vessels appears feasible.

The liquefied CO_2 prototype vessel designs are physically smaller than the large LNG vessels currently in service (capacity of 6 000 to 12 000 m^3). These may increase in size as the transportation of liquefied CO_2 by sea is established (as have LNG vessels historically); however, CO_2 is not expected to be transported over such large distances as LNG. The shipping of CO_2 is considered a more likely solution for the transport of relatively small masses, where pipeline construction is uneconomic. A single liquefied CO_2 vessel would be expected to make many shorter trips than an LNG vessel, increasing the effective transport capacity.[7]

The potential for 'dual use' vessels has also been suggested (IEAGHG, 2004) (Brownsort, 2015) where a single vessel might be used to transport LNG to a site, and then bring back liquefied CO_2 for storage in another location (potentially close to the LNG processing site). Although technically possible, this may not be an efficient solution, given the difference in

[7] LNG transport distance from Persian Gulf to Japan is about 12 000 km; Australia to Japan 6 000 km. Estimate based on CO_2 shipping distances closer to 600-1 200 km (1/10). A build-out of CO_2 transport capacity of 15-30 Mt CO_2 per year (120% of total) would require approx. 20 – 40 additional ships a year (carry capacity from (Gassnova, 2016)).

ideal transport pressure and temperature regimes for the two fluids (Table 3.1), which would lead to overdesign of the tanks for either fluid individually, and the delay required to completely clean out one fluid prior to refilling the vessel with another (IEAGHG, 2004).

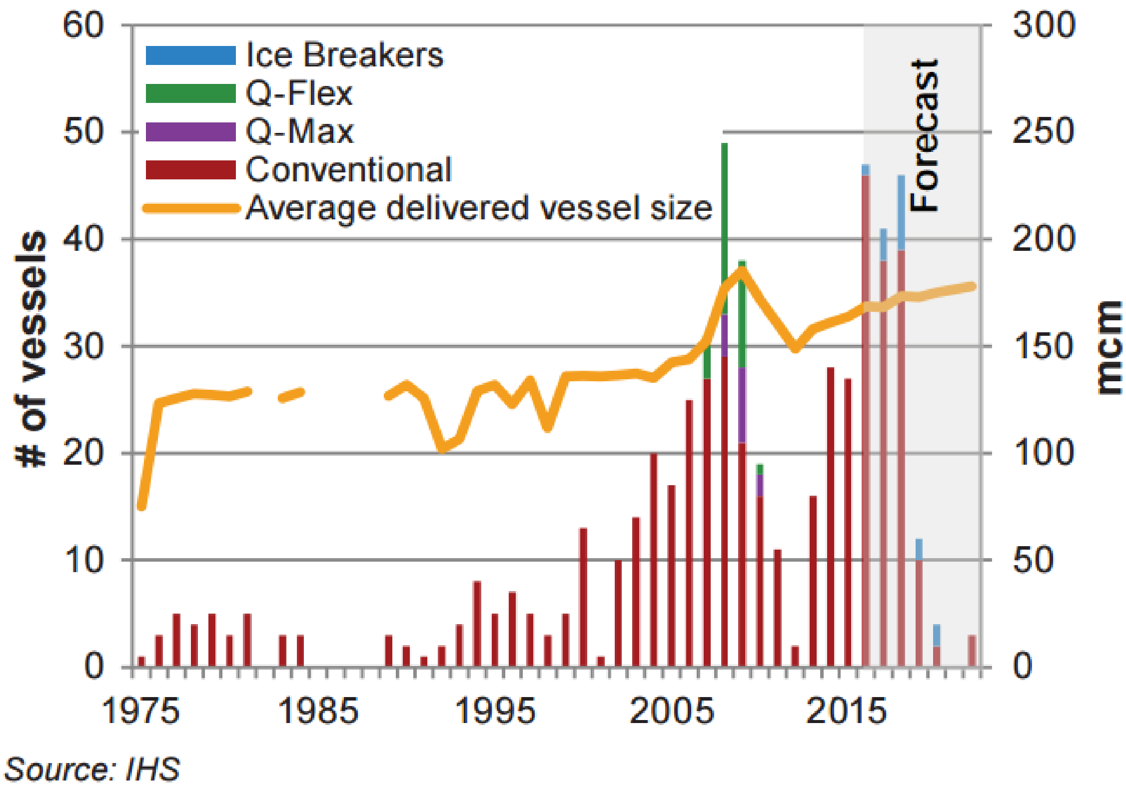


Figure 3.5: Global LNG fleet and average vessel size by year-of-delivery (International Gas Union, 2016)

The historic LNG data shows that technically increasing liquefied CO_2 transportation at the rate suggested (i.e. by an average of **15-30 Mtpa CO_2/year**) is achievable; however, the actual rate will strongly dependent on incentives in place.

4. Storage

To build-out the deployment of CO_2 geological storage, the global community requires sufficient deployment rates of geological storage resource[8] discovery (potential storage sites) and development of these geological storage resources through drilling of sufficient well numbers and injection facilities at the storage sites.

4.1 Storage Sites

To meet the geological storage requirements of the 2DS, it is necessary that global geological storage development adds an additional **150 – 300 Mt CO_2 storage capacity per year**; such that more than 80 billion tonnes of CO_2 will have been cumulatively stored after the just over thirty years to 2050 (IEA, 2016).

[8] A storage resource is a porous and permeable reservoir formation under a seal formation with the potential to contain injected CO_2. The capacity of the storage resource is represented by the mass of CO_2 that can be injected and contained for the foreseeable future (thousands of years) within economic targets (defined by capital development expenditure and operating costs per tonne stored, and minimum injection rates).

The global potential for storage site development is addressed in this report in terms of a defined 'storage site development project'. This storage site development project injects 5-10 Mtpa for twenty years (final cumulative CO_2 storage 100-200 Mt), which would thus require development of **30-60 storage sites annually**. This represents a plausible average storage site development project; the scale of which is similar to a minimum capacity filter applied for various regional screening studies; e.g. UK portfolio review by Pale Blue Dot applied a cut-off at 50 Mt capacity (Pale Blue Dot Energy, 2016), and the IEAGHG depleted gas field storage potential review cut-off minimum 50 Mt onshore and 100 Mt offshore (IEAGHG, CO2 storage in depleted gas fields, Technical Report 2009/01, 2009). A larger storage resource (e.g. a large basin wide reservoir unit such as the Mount Simon Sandstone, Illinois basin, United States (US DOE, 2012))[9], would be developed by multiple projects. Each 'storage site development project' would have five to forty wells, and one to two platforms, subsea templates or well pads. The variation in well numbers per project takes accounts of the variation in injectivity and the requirement for additional contingency wells, monitor wells and pressure relief wells. Global CO_2 injection operations experience indicates that CO_2 injection wells can inject from approximately 0.25 Mtpa to more than 1 Mtpa CO_2 (Pale Blue Dot Energy, 2016) (The CarbonNet project). An injection rate of 1 Mtpa is a reasonable target for a CO_2 injection well in an industrial storage project; however, to account for the potential requirement to drill additional wells in case of unexpected results (failed or poor wells, contingency wells) and any associated non-injection wells (for pressure relief or monitoring), it is assumed that, for each million tonnes per annum of CO_2 injection, an average of one to four wells would be required to support the geological storage activities.

Hence the global industry is anticipated to add thirty to sixty storage site development projects a year (thirty per year during the early build-out period, rising later as storage sites need replacing because the stores developed earlier have filled up).

The development of a hydrocarbon field necessarily involves both the discovery and appraisal of the resource, alongside the development activities (e.g. construction of platforms or well pads). Equivalent activities are required to discover and develop a subsurface CO_2 store utilising a saline water filled formation. The ability of the global oil and gas industry to find resources and construct the basic site development facilities to bring a new hydrocarbon field on stream is regarded as a good analogue for the future ability of the CO_2 storage industry to discover, appraise and develop geological storage sites.

The number of oil and gas fields developed per decade is in the thousands; during the recent, peak development period (2000-2010), production site development projects were completed at a rate of over 350 per year (see Figure 4.1).[10]

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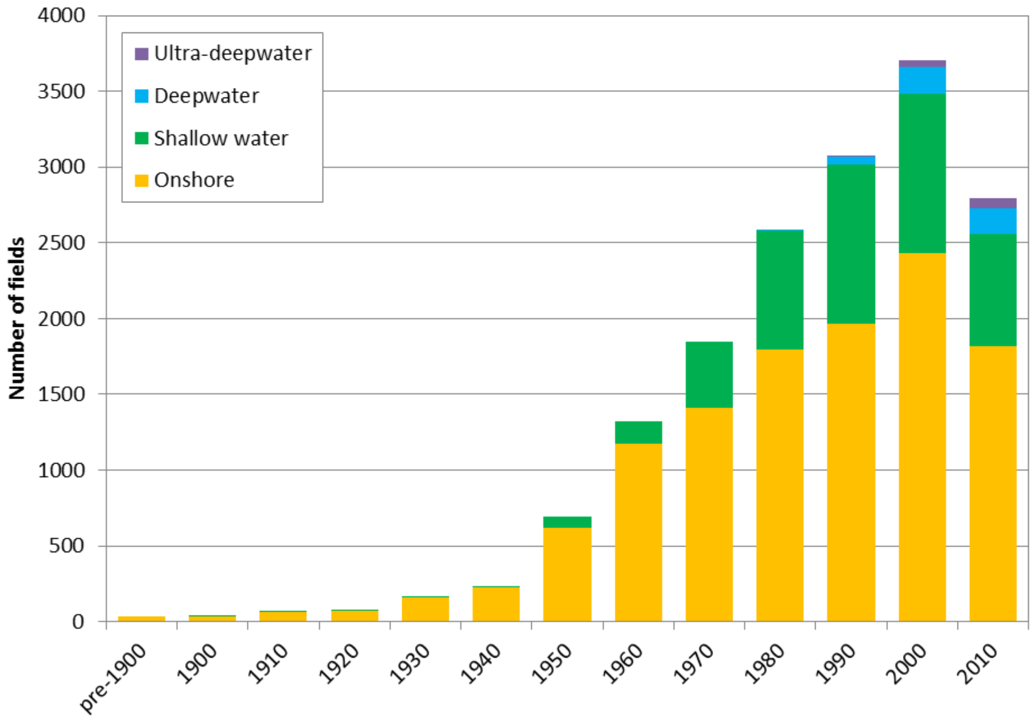
[9] The Mount Simon Sandstone extends across a significant area of the Midwestern USA; and is estimated to have large potential CO_2 geological storage capacity. A total storage capacity of more than 18 to 118 billion tonnes of CO_2 (low to high case estimates) has been proposed (US DOE, 2012). Hence the Mount Simon Sandstone could be utilised by multiple separate geological storage development projects as defined here (100-200 Mt total capacity utilized per storage site development), or fewer larger storage site development projects (1 billion tonnes total capacity utilized per storage site development)

[10] The 2011 IEAGHG report (IEAGHG, 2011) concluded that the storage site development as per the 2009 IEA CCS Roadmap (IEA, 2009) could not be attained in the short term (until 2020). The roadmap has changed significantly, in which the 2016 CCS Roadmap (IEA, 2016) sees less CO_2 captured and stored (5.5 billion tonnes of CO_2 per annum versus greater than 10 billion tonnes of CO_2 per annum by 2050); however, the gap between targets and current global CCS project portfolio remains. Near-term targets are still very challenging against the 2016 2DS timeline (IEA, 2016) due to project lead times.



Source: Global data extracted from the Wood Mackenzie Upstream Data Tool **(Wood Mackenzie, Q4 2016)**. Wood Mackenzie data cut 4th November 2016 (Q4). Downloaded for plot December 2016. [*Note that the Upstream Data Tool includes some inevitable data gaps due to unavailability; for this reason, ca. 9% of the developed fields in the database have no start date and could not be included in the plot. The database was filtered to include standalone and child Group data only to prevent double counting. Excludes unconventional fields and conventional fields with a floating LNG or unknown development type.*]

Figure 4.1: Number of oil and gas fields brought on-stream *per decade* by field location.

4.2 Discovery of storage resources

The rate of discovery and maturation of geological storage resources will be critical to the build-out of global CO_2 Storage.

Hydrocarbon exploration activities search for an overlapping occurrence of: suitable reservoir and seal formations; geological trap; and a hydrocarbon charge. A CO_2 geological storage resource does not require either hydrocarbon charge or a geological trap (see Table 4.12). Although the economic constraints (development cost per tonne of CO_2 storage capacity) for viable resources might lead to a more restrictive exploration area (maximum transport distance; unfavourable environment for monitoring), potential geological storage resources should be more readily discovered, and across a wider range of global locations (not limited to hydrocarbon provinces), than oil and gas.

Past experience has indicated that, while the discovery of storage resources is more straightforward, the maturation and de-risking of these resources can be a slower and more complex process compared to that of hydrocarbon resources. For example; while the presence of a hydrocarbon automatically indicates that the requirements for sealing caprock, trap and charge have been met; a suitable sealing caprock for CO_2 storage in a saline filled reservoir can only be demonstrated through data gathering, modelling and risk analysis (unless the project re-uses an old hydrocarbon field).

The potential rate of discovery and characterisation of storage resources is posited therefore to be analogous to that of hydrocarbon resources; however, the balance and focus of activities will be different (with less emphasis on the exploration phase, and more on the characterisation phase for storage versus hydrocarbon resources). Many of the exploration and appraisal data gathering activities applied to the search for and development of hydrocarbon resources (e.g. drilling, logging and testing wells, rock core analysis, and seismic surveying of the subsurface) are also used to explore and appraise for geological storage of CO_2. Indeed, data gathered during legacy hydrocarbon exploration activities provides a pre-existing dataset in many regions, which could accelerate early geological CO_2 storage site exploration.

Early development opportunities are expected to involve a potentially large proportion of hydrocarbon fields through recharging of depleted reservoirs or CO_2 EOR developments (where revenue from additional oil production can support early-mover projects). In these cases the containment of CO_2 (suitable seal and trap) and injection potential of the reservoir formation has been significantly de-risked upfront.

Hydrocarbon Resource	Storage Resource
Caprock that seals over millions to tens-of-millions of years	**Caprock** that seals over millennia **Migration pathway** of the injected CO_2 does not include leak paths Store not compromised by poorly plugged legacy wells Onshore, migration of formation brine does not contaminate drinking water resources
Geological trap (to hold the buoyant fluid that does not dissolve in water)	Geological closure not required because CO_2 can be trapped as it migrates (migration assisted storage) through dissolution, mineral, and capillary trapping (provided trapping occurs prior to migration to surface). Examples include the Sleipner project, Norway and Quest storage project, Canada.
Reservoir formation that can be produced from at required rates (i.e. sufficient permeability, thickness, connectivity) Adequate connected volume for a commercial target (total recoverable volume and rates)	**Reservoir formation** that can be injected into at required rates (i.e. sufficient permeability, thickness, connectivity) Adequate connected volume to allow pressure diffusion or ability to produce water to manage pressure
Hydrocarbon charge. A mature source rock and migration with a migration pathway into the trap.	Hydrocarbon charge not required. Charged reservoirs can be used for CO_2 storage post production (or simultaneously: CO_2 EOR development). Saline water filled reservoirs are also suitable CO_2 storage targets.
Improved oil recovery: via water (or other fluid) injection to maintain reservoir pressure	**Improved storage efficiency:** via water extraction to reduce pressure build-up

Note: The identification and mapping of these elements form the basis of resource exploration activities.

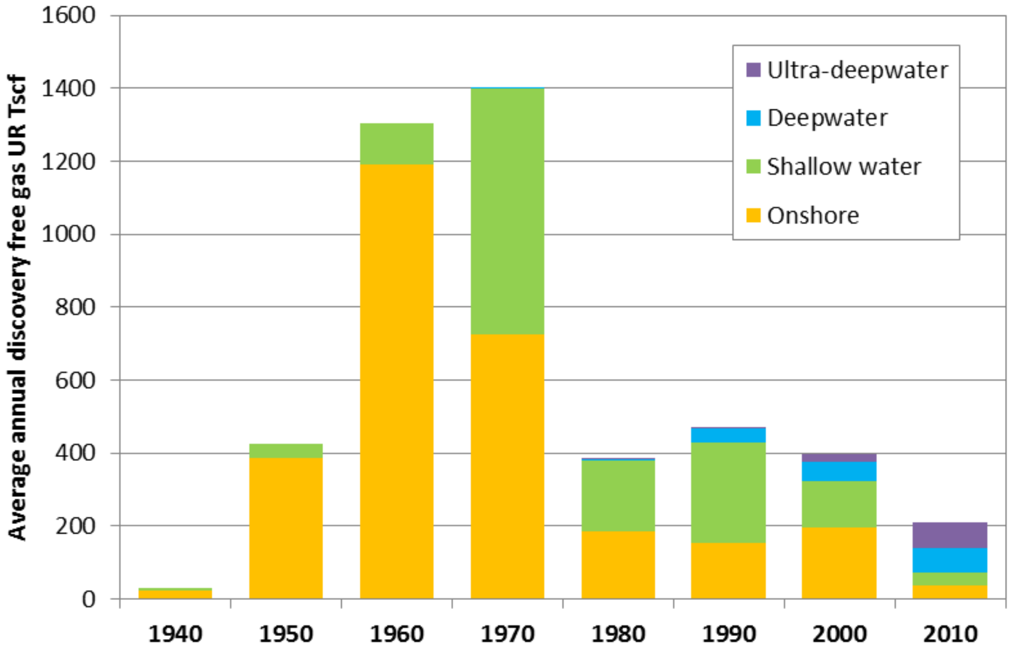
Table 4.12: A comparison of the basic elements required for hydrocarbon resources versus storage resources.

As with hydrocarbon fields, once one store has been developed within an area it provides an analogue that can de-risk and accelerate the development of other stores in the region with similar geology.

To meet the IEA 2DS projections (IEA, 2016), 80+ billion tonnes of storage must be discovered and developed within thirty years; which corresponds to a minimum discovery rate of approximately 3 billion tonnes per annum. To support the development of the required storage projects (and given that geological carbon storage activities will continue beyond the thirty year projection), geological storage resources sufficient to hold more than 80 billion tonnes of CO_2 must be discovered and characterised. In-line with the proposed twenty-year project life, if we assume that the active projects have an average of ten years remaining injection after thirty years (i.e. by around 2050 in the 2DS), and that these are injecting at a global rate of 5.5 billion tonnes of CO_2 per annum, then to meet the target (5.5 billion tonnes stored per annum; plus 80+ billion tonnes cumulatively stored) an average of 4.3 billion tonnes of developable storage capacity must be discovered per annum (an additional 55 billion tonnes capacity). For continued growth of global CCS activities, up to 6.5 billion tonnes of developable storage capacity must be discovered per annum to allow global injection rates to increase further.

The thirty-year 2DS numbers are supported by historic gas discovery rates. The data indicates that an average of 580 tscf (15.5 tcm = 15.5 trillion cubic meters = 15.5 x 10^{12} standard m^3) of conventional commercial gas resources have been discovered annually since 1940, with a peak discovery period of more than 1 300 tscf (35 tcm) of recoverable gas discovered a year in the 1960's and 70's. This represents an average equivalent subsurface CO_2 storage resource discovery of 6 billion tonnes per annum[11]. Meeting the proposed high case (continued growth of CCS activities) will be more challenging and would rely on increased exploration efficiency given the experience gained through the earlier phases of dedicated geological storage exploration and development.

[11] Hydrocarbon gas discovery volumes are converted to approximate equivalent CO_2 storage masses using a conversion factor comparing the density of methane (bulk component of hydrocarbon gas) and CO_2 at analogue reservoir conditions (Goldeneye Captain Sandstone reservoir; 2500 m below sea-level, 25 000 kPa & 82°C; CH_4 143 kg/m3 versus CO_2 676 kg/m3. (Shell U.K. Limited, 2015)). This analysis approximates that the timescale of activities to discover a gas volume (gathering and interpreting seismic data, and drilling an exploration well) will approximately correlate to those to discover the equivalent storage volume. It is noted that although the subsurface volume is compared directly here, CO_2 injected for storage is likely to generate a larger pressure footprint than that of a gas development project. This may be compensated for through water production activities.



Source: Global data extracted from the Wood Mackenzie Upstream Data Tool **(Wood Mackenzie, Q4 2016)**. Wood Mackenzie data cut 4th November 2016 (Q4). Downloaded for plot December 2016. The plotted data includes only those fields listed as hydrocarbon type gas or gas/condensate, conventional and commercial discoveries. The database was filtered to include standalone and child Group data only to prevent double counting.

Figure 4.2: Recoverable volume of gas discovered per decade by field location. [The average annual ultimately recoverable (UR) gas resource volume discovered over the decade is plotted.]

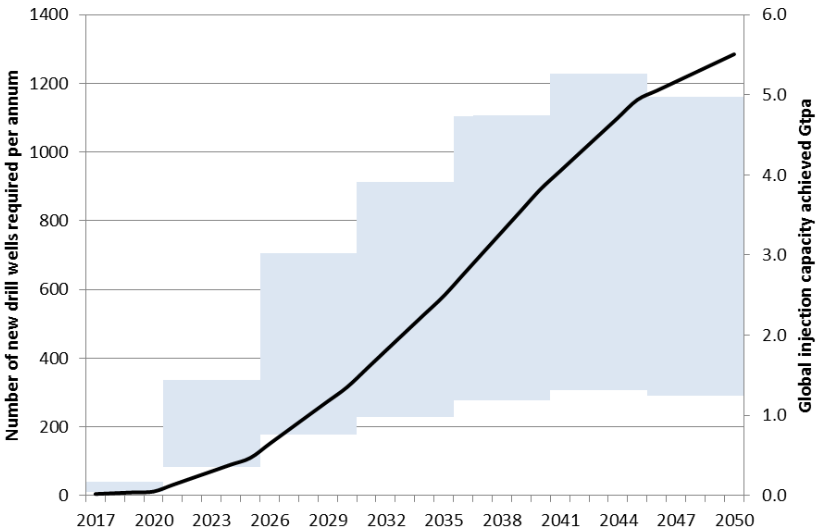
Published global assessments of storage capacity, and compilations of regional assessments, indicate 1 000 - 30 000 billion tonnes of global storage capacity (IEAGHG, 2016); far in excess of the required storage capacity to achieve the 2DS targets. The bulk of these reported resources are currently relatively immature volumetric estimates and the portfolio capacity would reduce as it is matured (and theoretical storage capacities and rates are matched with actual regional sources); this would be partially offset by the inclusion of resources from regions barely assessed to date. Work is ongoing to align and mature resource classification and global storage capacity estimates in the Global CCS Institute (GCCSI), Oil and Gas Climate Initiative (OGCI) and the IEAGHG.

Hence it is tenable that the build-out rates for CO_2 storage resource discovery and development could be achieved.

4.3 Drilling wells and rigs

The type of wells drilled for CO_2 storage operations are very similar to those currently drilled by the oil and gas industry, both in terms of equipment (for both drilling and completing the well), and in terms of the well targets (depth, temperature, pressure and rock type). Hence the development of historic global drilling capacity for oil and gas wells is a suitable analogue for future drilling capacity build-out for CO_2 storage wells.

This analysis estimates that for the development of each 1 Mtpa CO_2 injection capacity, the number of wells drilled must range from one to four. This accounts for failed wells, poor injectivity, monitoring and water production wells (see Section 4.1). Additionally, oil and gas wells cannot function indefinitely without eventual replacement of materials or of the well itself. A conservative average well life of twenty years is assumed here. On this basis it can be estimated that the requirement to drill new wells for CO_2 storage projects will reach numbers of between **300 and 1 200 new wells per year**, after twenty-five years growth, i.e. by 2041 to 2045, depending on the average injection rate supported per well (Figure 4.3). To build-out the capability to drill 1 200 wells a year by 2040, the industry must build-out the drilling resources (drilling rigs[12] and crews) available for CO_2 storage activities, such that an additional 55 wells might be drilled each year, compared to the number of wells drilled in the preceding year.



Note: Blue shaded range (left axis) indicates the number of wells required. The range reflects a possible range of average CO_2 injection supported per new-drill well given variable injectivity and use (potential additional wells for monitoring and pressure relief). The black curve represents the global annual injection capacity (right axis) supported by the active storage project wells.

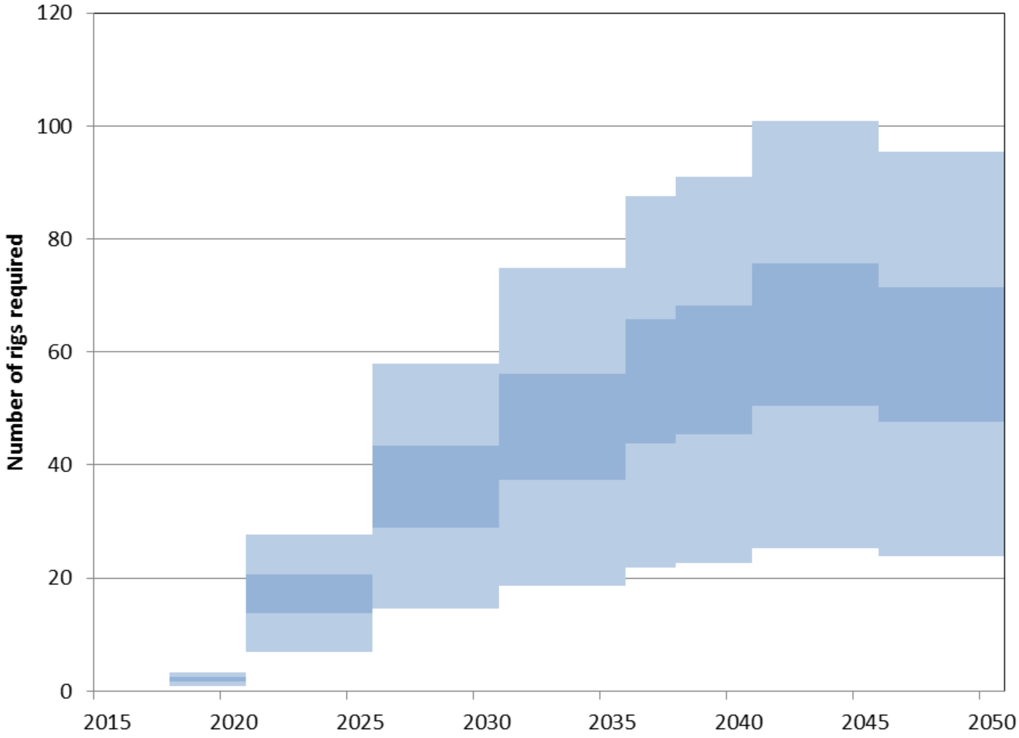
Figure 4.3: Range of new storage project wells required year-on-year to meet the IEA 2DS targets to 2050.

The Goldeneye Natural Gas (NG) development (Shell U.K. Limited, 2015) is used as an analogue for a CO_2 storage development. This project targeted a gas reservoir at approximately 2 500 m below sea-level (at the deeper end of the range expected for storage projects, i.e. from around 1 000 to 2 500 m below sea-level), in an offshore North Sea location. The original hydrocarbon field was developed with five producing wells, each of which took an average of thirty-six days of rig-time per well.

The Baker Hughes data on US land wells versus drilling rig count, for the period from 2012 to 2014, indicate that these wells take, on average, less than twenty days rig-time per well (Baker Hughes, 2014). The actual rig time will vary significantly from project to project depending on site location (onshore, offshore, deep water) and target depth. For this analysis, a range of rig days per well from fifteen to ninety is assumed (thirty-day base case). Thus to achieve the storage project build-out required to meet the IEA 2DS projections, it is estimated that **40 to 100 drilling rigs/year** would be required during peak development (see Figure 4.4). Based on

[12] A drilling rig is an assembly of equipment and machinery used to drill holes into the earth's sub-surface (including water, oil, or natural gas extraction wells as well as water or gas injection wells). A drilling rig is normally mobile (can be moved from site to site to drill a well before moving to another location) or might be built permanently onto a hydrocarbon development structure.

the assumption that each project would have 1-2 wellpads/platforms, **60-120 wellheads/platforms per year** would need to be installed. In a scenario where all storage project drilling is slow (90 days per well), and each well drilled only supports 0.25 Mtpa of injection capacity, then approximately 300 rigs will be required to meet peak expansion of storage capacity (up to 1 200 wells drilled in a year). Peak demand of 40 to 100 rigs is approximately the equivalent of an annual addition of one to twenty drilling rigs dedicated to storage project drilling (in addition to the number of rigs assigned to storage activities in the previous year) over thirty years to build-out development capacity.

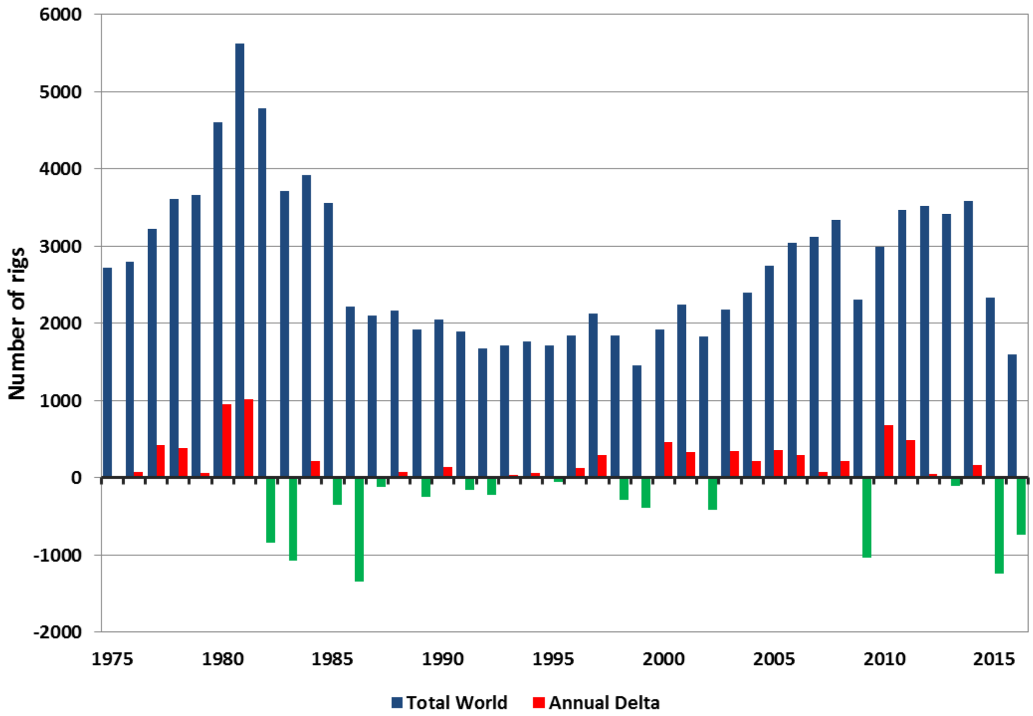


Note: The blue shaded range represents a low to high case scenario based on variation in average well injection rate and average rig time per well. The darker blue shaded area represents the most likely range.

Figure 4.4: An estimate of the total number of rigs, actively developing storage projects, required to meet the target global CO_2 injection projection.

Historic global rig numbers (Baker-Hughes data; a weekly census of the number of drilling rigs actively exploring for or developing oil or natural gas) reports an average count of 1 593 rigs for 2016 (Figure 4.5). Comparing active rig counts reported over the past forty years it can be observed that the active count frequently increases or decreases year-on-year in the order of 300 rigs; with increases as large as a 500 rigs observed from 2009 to 2010 and again to 2011 (and significantly larger increases observed in the 1970s). The maximum projected annual rig storage project requirement would be 300 (combining low injectivity wells with slow drilling rates), which is less than 20% of the 2016 rig count. An average year-on-year global increase of twenty drilling rigs for storage projects is less than a 2% increase compared to the 2016 active rig count.

Historic rig count data demonstrates that new rigs can be constructed (or reinstated) quickly in response to increased demand (see initial industry ramp-up and the increase in active rigs observed between 2000 and 2010) and that the additional rig requirements to support the development of sufficient CO_2 storage projects is modest compared to historic trends.



Note: Figure 4.5 plotted from Baker-Hughes rotary rig count data (Baker-Hughes). Rig count annual delta plots as red bars for rig count increases, and green for rig count decreases, from one year to another. Note that the annual rig count regularly changes of the order of 300 rigs, and that this may occur for several years in succession (e.g. 2003 to 2007).

Figure 4.5: Average global active rig count and change in year-to-year rig count

5. Analogy and regional differentiation

While using historical analogies to illustrate experience in other industry sectors is useful to explore the feasibility of physical build-out rates, it should be recognised that analogies have their limitations, for example:

- The value chains considered have different complexities and characteristics;
- Historic rates may be more complex to realise in a future with shifted positions on large-scale infrastructure developments;
- The nature of market incentives and public support will differ between regions.

The analogies explored for the most part show the effect of sudden pulls from market incentives and public support, thus high rates of build-out can be seen for shorter periods of time. This serves to illustrate that, with sufficient motivation, industries can adapt to realise impressive growth in supply chain development and applications. However, it is also recognised that it will take time to scale up to the growth rates discussed here. This is, in part, due to the lead time required by CCS projects. Storage exploration, appraisal and development could require around 10 years before a final investment decision was be taken (ZEP, 2014), which is longer than needed to develop capture and transport. Regulatory requirements, the subsequent construction of facilities themselves and the build-out of supply chain will further add to the lead time before start up.

Given the CCS projections shown in Figure 1.1, CCS build-out will be a significant undertaking and will require strong incentives, strong and stable policies, fit for purpose regulatory frameworks, and public support to sustain such high growth rates for the CCS industry over a few decades. This might be in parallel with oil and gas development, which may imply competition for resources (including pore space, skills), or alternatively the growth of both sectors with the associated increases in jobs and GDP. In some regions, CCS infrastructure development may offset job reduction from oil and gas production decline.

It is also clear that there will be differences in regional development. Considering analogies, it is, for example, understood that the US shale gas revolution had strong roots in the regional endowments and commercial possibilities, which would make it hard to replicate such a development in other regions. In CCS, there are technical factors which would also be very much dependent on regional aspects, such as geology and thus access to CO_2 storage, as well as pipeline infrastructure routing through e.g. congested areas or areas of a sensitive nature, and local situations such as work force and equipment. However, history has also shown that sufficient incentives to realise an application would help deliver new solutions. An example is access to natural gas resources, which is similar to access to CO_2 storage, for which a whole new LNG value chain was created to correct regional imbalances in supply and demand and a shale gas “revolution” for energy access.

6. Conclusions

The CCS industry requires rapid and sustained build-out in order to deliver its contribution to climate goals. While this is a substantial task in terms of physical supply chain growth, analogies from related industry sectors show that comparable build-out rates have been realised under sufficiently strong incentives, regulation and market pull. Although it is recognised that the analogies have limitations, it seems tenable technically that anticipated CCS build-out rates can be realised in a supporting environment, with sustained incentives.

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Pure Offices, Cheltenham Office Park, Hatherley Lane,
Cheltenham, Glos. GL51 6SH, UK

Tel: +44 1242 802911 mail@ieaghg.org
www.ieaghg.org