



REDUCING THE COST OF CCS DEVELOPMENTS IN CAPTURE PLANT TECHNOLOGY

An insights report from the
Energy Technologies Institute

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CCS uses proven technologies, combined into new value chains but the high capital cost means technology risks have to be carefully managed

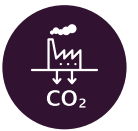


Cost reduction can be achieved without creating new capture technology platforms



making use of economies of scale, sharing infrastructure and risk reduction through deployment

REDUCING THE COST OF CCS



DEVELOPMENTS IN CAPTURE PLANT TECHNOLOGY

The cost of capture is the largest single cost element in CCS



Today's capture technology is from a mature technology base but further improvements in cost and performance are expected



A sequential, co-located series of deployments in the UK using existing technology can reduce initial "demonstration" costs

by up to **45%**

exceeding the likely cost reductions from technology advances



After **2030**

technology innovation should play an increasing role in ongoing cost reduction



CCS combined with hydrogen storage can provide considerable flexibility and improve energy security



Post combustion amines and pre-combustion gasification technologies will continue to be the capture technologies of choice in power production for several years



EXECUTIVE SUMMARY

- > Successfully deploying Carbon Capture and Storage (CCS) would save tens of billions of pounds to consumers and businesses – providing low carbon electricity, capturing industrial emissions, creating flexible low carbon fuels and delivering negative emissions in combination with bioenergy.
- > CCS is a combination of proven technologies. Injection of CO₂ from an ammonia plant for enhanced oil recovery (EOR) began as far back as 1972 and “first intent” CCS began at Sleipner in 1996. By 2017 22 plants will be running CCS technology applications, spanning post combustion and pre-combustion coal, natural gas steam reforming, bioenergy CCS (corn to ethanol), and applications from power, gas production, refining, chemicals and steel.
- > The potential for cost reduction through deployment is significant:
 - Investment in anchor projects provides transport and storage infrastructure for subsequent projects to build on.
 - Reductions in scope and increased project sizes to exploit economies of scale.
 - Risk reduction during the early stages of CCS deployment should attract more competitive financing. Developers in the US, UK and Canada have committed to publically sharing their CCS designs and early operational experiences such that future projects can benefit.
- > Additional cost reduction can be achieved through innovation in capture technology:
 - Post combustion capture, based on mature amine gas separation technology, has seized the largest share of the power market and still offers opportunities for further improvements.
 - Pre-combustion gasification technology potentially offers a clean, flexible alternative for coal, biomass and waste and significant research, development and demonstration (RD&D) funding is resulting in continuous improvements, now feeding into demonstrations.
 - Other promising options using membranes, hydrates, cryogenics, enzymes, fuel cells and carbonate chemistry are actively being developed, and progressing towards commercialisation, such as vacuum swing adsorption (VSA) in a refinery in the USA. Post combustion temperature swing adsorption (TSA) has the potential to compete with amines in the future, but next generation adsorbents are still at a relatively early stage of their development.

- NET Power’s supercritical CO₂ technology has the potential to be a game-changing technology. It faces several new challenges in equipment design and operation, but testing is under way. It is likely to take several years before it can be demonstrated at full scale.
- > Given the current immature status of the next generation of alternatives, amines or pre-combustion are likely to be the most investable options for the next five to ten years.
- > One pathway to reducing the cost of CCS is deploying a small number of full scale plants sequentially (at least three), based on

established technologies. Our analysis strongly suggests that risk reduction through sequential deployments of existing technology in the UK can drive output energy costs down by as much as 45%, largely through a combination of increased scale, infrastructure sharing and reductions in financing costs. This paves the way for the introduction of higher risk emerging technologies once the overall CCS risk is reduced.

Exploit
economies of
scale

Share
infrastructure to
reduce cost

Risk
reduction to
lower financial
costs



CONTEXT

ETI's work has consistently shown that a successful UK CCS sector could save UK consumers and businesses tens of billions of pounds (in the order of 1-2% of GDP) from the annual cost of low carbon energy.

As well as providing low carbon electricity, CCS can capture industrial emissions, create flexible low carbon fuels and deliver negative emissions in combination with bioenergy.

The ETI has carried out modelling of CCS at process plant, techno-economic, financial and energy system level in order to build knowledge of the role and value of CCS and to better understand the barriers facing the industry. Much of the work has been on risk and cost reduction in CO₂ transportation and storage, but in this insight report, we look at the cost of capture, which is the largest single cost element in CCS.

The capture technologies currently being deployed are from a mature technology base (deployed for over 80 years in processing industries), entirely appropriate given that risk management in this early stage of CCS deployment is extremely important if we are to build an industry that attracts private sector finance. In the light of extensive development programmes, we expect these technologies to improve in cost and performance.

Breakthrough technologies, whilst potentially game-changing, are expected to take a number of years before they can be demonstrated at scale and are best placed to enter the market once the overall risk involved in CCS is reduced.

CCS could save
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Capture technologies
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INTRODUCTION TO CAPTURE TECHNOLOGIES

CO₂ has been extracted from hydrogen plants and natural gas plants for use in EOR since 1972.

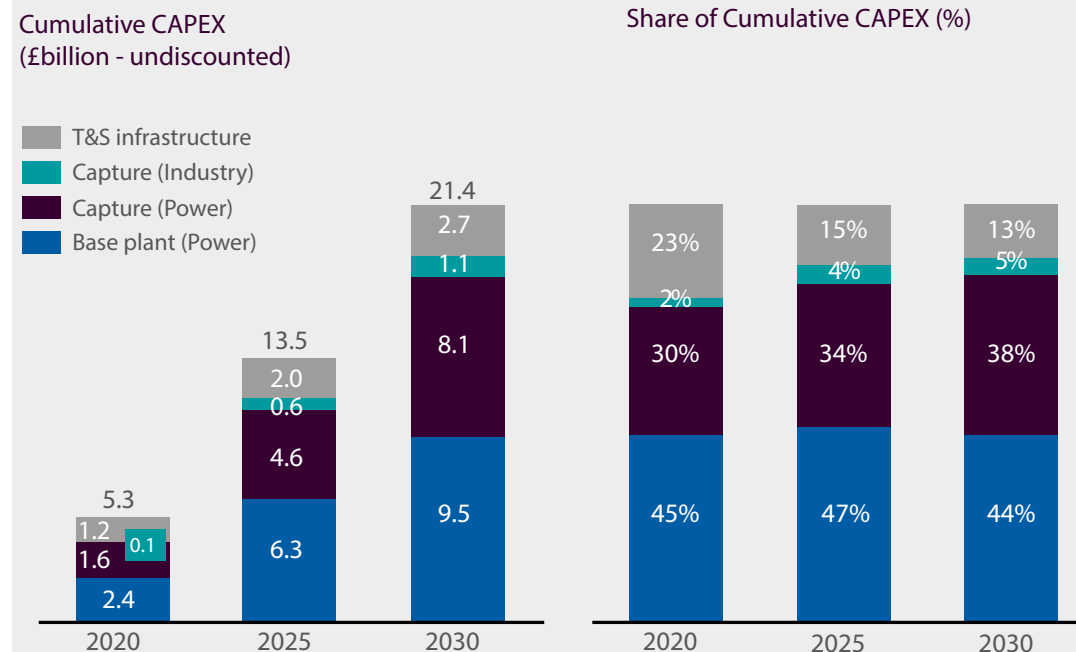
Conventional amine technology has been used to separate CO₂ from natural gas at the Sleipner gas field in Norway since 1996 where it is stored purely for environmental reasons (CCS). Further natural gas amine applications were developed at In Salah in Algeria and at Snohvit in Norway in 2004 and 2008 respectively. More recently, Sask Power has been running Shell's Cansolv process at a coal plant at full scale for over a year and so this option has been uniquely derisked for coal power stations, and a real First of a Kind (FOAK) cost base established from which reductions could be made.

Cancellation of the DECC CCS Commercialisation Competition in the UK and consequently the Peterhead project will delay the demonstration of the Cansolv process on a gas (CCGT) power

plant. Pre-combustion technology should be operational at Kemper County power station in 2016. CCS plants for hydrogen production (Canada, USA) have been operating since 2013 and several industrial CCS plants are in construction. By 2017 22 plants in eight countries will be running full chain CCS technology spanning post combustion and pre-combustion coal, natural gas steam reforming, bioenergy CCS (corn to ethanol) and applications in the power, gas production, refining, chemicals and steel sectors according to the Global CCS Institute Project Database.

Capturing CO₂ from a power station incurs additional capital cost, similar to the cost of the original power station and in itself uses up to 20% of the power station output. Studies of the costs of CCS networks in a UK deployment scenario to 2030 are shown in Figure 1¹.

Figure 1
Capital Costs of building a 50Mt/a CO₂ ("10GWe") CCS network (£Bn 2014 undiscounted)¹



¹ Element Energy, Poyry. (2015). CCS Sector Development Scenarios in the UK. Available at <http://www.eti.co.uk/wp-content/uploads/2015/05/2015-04-30-ETI-CCS-sector-development-scenarios-Final-Report.pdf>

INTRODUCTION TO CAPTURE TECHNOLOGIES Continued

These show that the capital costs of capture plant should level out at over two thirds of the total additional capital costs CCS imposes on the power stations. The balance is taken up by the costs of transportation pipelines and storage infrastructure (T&S).

Much of the work tackled by the UK CCS community, including the ETI^{2,3,4} has focussed on capital savings from storage networks, risk reduction by storage appraisal and the challenges of financing these large, capital intensive projects. In this insight we focus on the costs of capture, and specifically the implications of technology selection and its accompanying risks and performance issues. The ETI's evidence base includes data obtained from a series of techno-economic "bottom-up" benchmarking studies carried out by Amec Foster Wheeler Ltd and others on its behalf.



Courtesy of National Grid



Chapter Summary

- "First intent" CCS (as distinct from EOR) has been operational since 1996 and by 2017 22 plants in eight countries, each building confidence in CCS, will be operating at scale
- The diversity of technologies in early applications means that no individual capture technology has gone far down the learning curve, and there is significant scope for cost reduction

HOW GOOD ARE TODAY'S CAPTURE TECHNOLOGIES?

Theory tells us that the ideal way of separating CO₂ from power station flue gas would only require a fraction of the energy today's processes actually use. However, as soon as the practicalities of separation processes are addressed (i.e. operating at any reasonable rate, in conventionally sized, economic equipment) useful energy is "wasted" or "lost" from the process undertaking a variety of different tasks. Few gas separation processes work near their theoretical minimum work (power) requirement.

Figure 2 compares the performance of the typical post combustion processes benchmarked by the ETI with the theoretical minimum work⁵ needed to separate CO₂ from flue gases by post combustion absorption with "state of the art" amine solutions. These solutions have been used successfully for CO₂ removal from gases for decades, but the application to power will require robust, reliable and possibly agile plant performance at the lowest possible cost.

Figure 2
Separating CO₂ from Gas fired (CCGT) and Coal fired Flue stacks

	CCGT Flue Stack	COAL Flue Stack
Concentration of CO ₂ , vol %	4	14
Theoretical Minimum Work needed to Separate CO ₂ , MJ/te	200	160
Theoretical Minimum work of CO ₂ Compression to 150 Barg, MJ/te	225	225
Total theoretical minimum work, MJ/te	425	385
Actual Work used in ETI Benchmark models to separate CO ₂ , MJ/te (reboiler duty)	940	575
Actual Work used in ETI Benchmark models for CO ₂ Compression, MJ/te	320	320
Other Capture related work in ETI Benchmark, MJ/te	470	105
Total actual Capture related work used in ETI Benchmark models, MJ/te	1730	1000

2 Gammer, D. (2014). A picture of CO₂ storage in the UK. [online]. Available at www.eti.co.uk

3 Day, G. Whelan, A. (2014) Developing a commercial and financial framework. [online]. Available at www.eti.co.uk

4 Day, G. (2015) Building the UK CCS sector by 2030 - Scenarios and actions. [online]. Available at www.eti.co.uk

5 NIST Chemistry Web-book. (2008) Thermodynamic data, [online]. Available at <http://webbook.nist.gov/chemistry/>

HOW GOOD ARE TODAY'S CAPTURE TECHNOLOGIES

Continued

It can be seen that the processes modelled use 2.6 – 4.1 times the minimum work requirement to separate and compress CO₂. This is not unexpected for gas separation processes, but shows that there is room for improvement to these amine systems and room for other amine based processes and “non - amine” technologies to compete if they offer similar or better capital cost structures. Evidence of potential improvements to amines is the progress made on bi-phasic systems (both liquid-solid and liquid-liquid) in recent years⁶.

Capital costs and energy penalties for the key post combustion amine technologies at 1GW scale are tabulated in Figure 3. Feedstock costs, cost type and financial parameters used in these estimates are given in Appendix A (page 32).

In terms of capital costs, adding CCS doubles the cost of CCGTs, and CCGTs with CCS are half the cost of coal with CCS, with simpler,

shorter, lower risk construction projects. It can be seen that adding CCS significantly increases the capital intensity of power production. This is further increased by the capital involved in pipelines and offshore storage, although in a mature network T&S is only expected to add around £10/MWh to power costs. Coal of course usually has a lower variable cost than gas, and will therefore be despatched before gas, but coal carries significant fixed costs and increasing environmental abatement expenses. Fossil fuels have higher running costs than renewables or nuclear but are flexible so will be load following. This increases their levelised cost and investment risk, favouring low capex options. If legislation requires coal to be abated to the extent it matches unabated CCGT (say 400g CO₂/kWh) new coal investment is difficult, as even the variable costs of coal (including a T&S tariff and non-fuel variable costs) are then not guaranteed to be lower than gas.


Much of the capture costs stem from handling the huge volumes of low-pressure gases involved in post combustion capture. Pre-combustion technologies have a theoretical advantage in this respect due to high-pressure operation, but have not yet been able to capitalise on this, in part because the unabated versions have a higher cost base than their unabated post combustion competitors.

Stepping away from amines, analysis of new power cycles and other novel approaches (e.g. NET Power as described on page 24) suggest that step changes in performance are feasible.

Figure 3
Costs for power stations with and without post combustion capture

Cost for Power with and without capture plant	CCGT	CCGT CCS	PC COAL	PC COAL CCS
Capital Cost, £/kWnet	550	1240	1480	2560
Efficiency LHV, %	58.8	49.9	42.4	32.8
Levelised Cost of Electricity (LCOE), £/MWh	48	69	56	87
Levelised Cost of Fuel Only, £/MWh	34	40	21	26

6 J. Zhang. (2011) Improvement of lipophilic – amine-based thermomorph biphasic solvent for energy-efficient carbon capture. [online]. Available at https://www.sintef.no/globalassets/project/tccs6/presentations/a2/04_002_improvement.of.lipophilic-amine-based.thermomorph.biphasic.solvent.for.energy-efficient.carbon.capture_zhang.pdf



Chapter Summary

- Post combustion capture is reasonably efficient, but there is scope for improvement, and alternative capture technologies are developing
- CCS increases the requirement for capital very significantly, moving power from gas from a fuel dominated cost structure towards a capital dominated cost structure
- There are significant gains to be made if a breakthrough technology can be developed



THE EFFECTS OF RISKS IN HIGHER CAPITALISATION

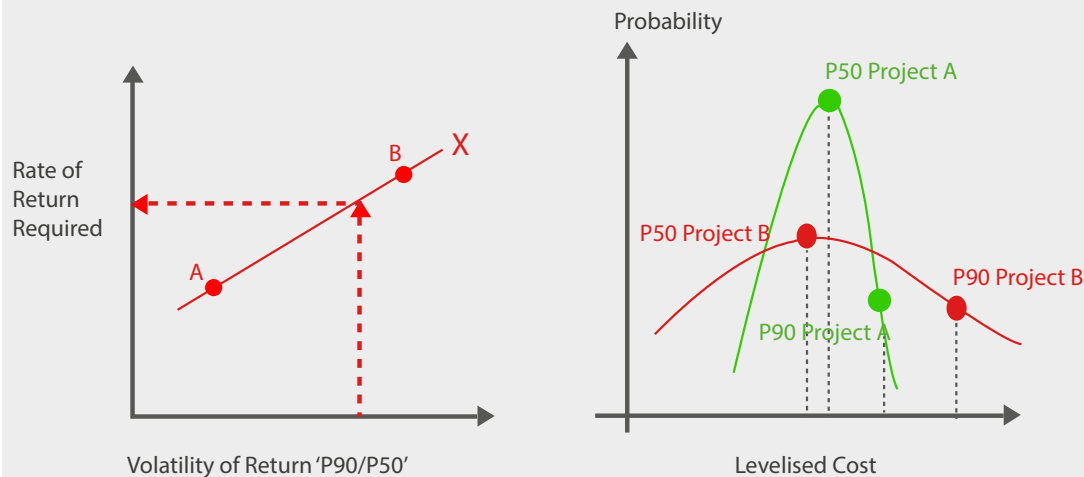
Whenever substantial capital is required for a project, financial risk assessments will be carried out on competing proposals, which will focus on the spread of potential costs and performance across the whole of the CCS chain. Such assessments will also examine the expected role the asset could play in the energy system (most likely baseload, transitioning to load following). ETI engaged Pöyry and URS to examine the effects of different project risks on their investability. Investors may favour certainty of returns over probable return when assessing projects. As shown in Figure 4, different technology selections and project configurations may have very different risk profiles. The spread of costs is often expressed in terms such as P90, which is the cost at which the constructor is 90% sure they will complete the project within (i.e. towards the high end of his estimates) and P50, the cost at which they are as likely to underspend as overspend. The volatility in the returns for a project (as characterised by the ratio of P90 to P50 costs in Figure 4) were correlated by Pöyry to a required rate of return by the finance market, using similar curves for other energy sectors. These are depicted in the left hand side of Figure 4. At some point (to the

right of "X" in Figure 4), the volatility will be outside "normal ranges" and the project would be "too risky" and not investable by the private sector. So even though the P50 cost of Project B is lower than for Project A, Project B is more risky and may be less attractive to investors.

"P90" and "P50" costs for key technologies were estimated by building up a "subjective" range of costs and performance for individual CCS components (generator, capture, store etc) for the different risks financiers would consider (construction, technology, policy etc). A new technology, offering potential for lower cost but having technical risks which are difficult to mitigate, would generally have a higher uncertainty spread in performance and be considered a high financial risk (as in Project B).

The role increased capital plays in decision making is illustrated in Figure 5, page 13 which shows the levelised costs of power from construction of multiple, consecutive gas power stations (CCGTs with CCS) filling a common offshore pipeline and store. These costs are simple 'P50' levelised costs, and not 'strike prices' as used in 'Contracts for Difference.'

Figure 4
Different choices of technology and scope will demand different rates of return

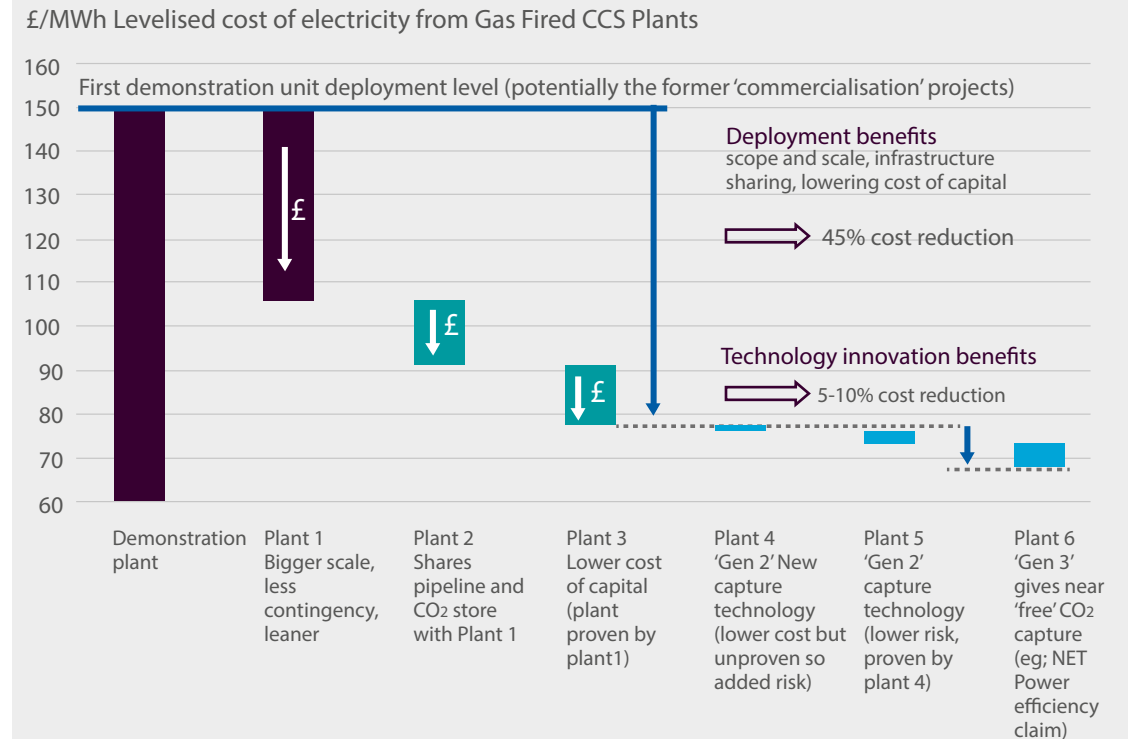


Increasing the scale from the demonstration unit to 'Plant 1' (the first true 'commercial' plant in scale and operation) we would expect cost benefits from increased scale and simplification. A subsequent 'Plant 2' then improves costs further, primarily by sharing the pipeline and storage infrastructure laid down by the demonstration plant and 'Plant 1.' 'Plant 3' then offers the potential to benefit from better finance terms as a result of Plants 1 and 2 being proven across the complete chain of power plant, pipeline and CO₂ store ('Plant 3' is assumed to be built a few years after Plants 1 and 2). Together, these opportunities result in Levelised Cost of Energy (LCOE) reductions totalling up to 45% from the demonstration plant. In this particular roll out sequence, the lion's share of cost reduction is done without a novel capture technology platform, and is effected by scale, scope, shared infrastructure and risk reduction.

With market confidence in the operation of CCS and the full chain business model (capture, transport and storage), we would expect that introduction of new technology and innovation could then drive a further 5-10% reduction from the "Plant 3" cost baseline.

'Plant 4' introduces a new, more efficient, CO₂ capture technology offering 20% capital reduction in capture and a 3% point efficiency improvement. Although these gains are substantial, this first 'Generation 2' plant will almost inevitably be seen by finance groups as increasing technical risk from Plants 1-3, resulting in limited net cost benefits.

Figure 5
Driving the cost of CCS down – scale and scope, shared infrastructure and risk reduction



THE EFFECTS OF RISK IN HIGHER CAPITALISATION

Continued

However, once derisked the gains will be secured in 'Plant 5', constructed when the technical benefits of Generation 2 technology have been validated to the satisfaction of new investors.

Plant 6' is where a new, fully demonstrated technology ('Generation 3') has nearly eliminated the costs of CO₂ capture completely (for example approaching NET Power's claims, on page 24). Only then, after a minimum of seven investments, do costs approach those of an unabated plant. Our assessment is that the improvement in economics from capture technology is much less than the savings created as a result of deployment. Returning to Figure 3 (page 10) it can be seen that the difference in levelised electricity cost between full scale gas plants with and without capture, in other words the value in new technology totally eliminating the burden of capture, is only £21/MWh, all other risk factors and costs being constant.

The deployment driven savings in Figure 5 (page 13) are similar to the findings of the 2013 CCS Cost Reduction Task Force which highlighted the immediate economic benefits of deployment as being a much more important lever than detailed technology improvements resulting from ongoing R&D.

Together with a similar analysis for coal, this suggests that even without claiming cost savings from "learning" or "repeating" use, the very fact that a technology is proven will encourage technology "lock-in" to dominate the early CCS projects, at least until such time that the overall perceived risk of CCS reduces.

Once amine technology has progressed down the technology and construction learning curve, emerging game-changing capture technologies will face a stiff challenge to compete. However, the size of the current cost penalty, the multitude of state led programmes and the diversity of technical approaches (e.g. membranes, solid adsorbents, fuel cells) suggest there is potential to do so. Performance improvement over amines may ultimately be essential if the technology is to command a significant position in the power market.



Chapter Summary

- Adding CCS not only doubles the capital cost of a gas power plant, but the extra capex has a high-risk premium
- Risk reduction of CCS projects is a key driver for cost reduction, and will be needed to encourage private sector investment
- Consecutive deployment near a large store reduces the early cost premium to a greater extent than technology development

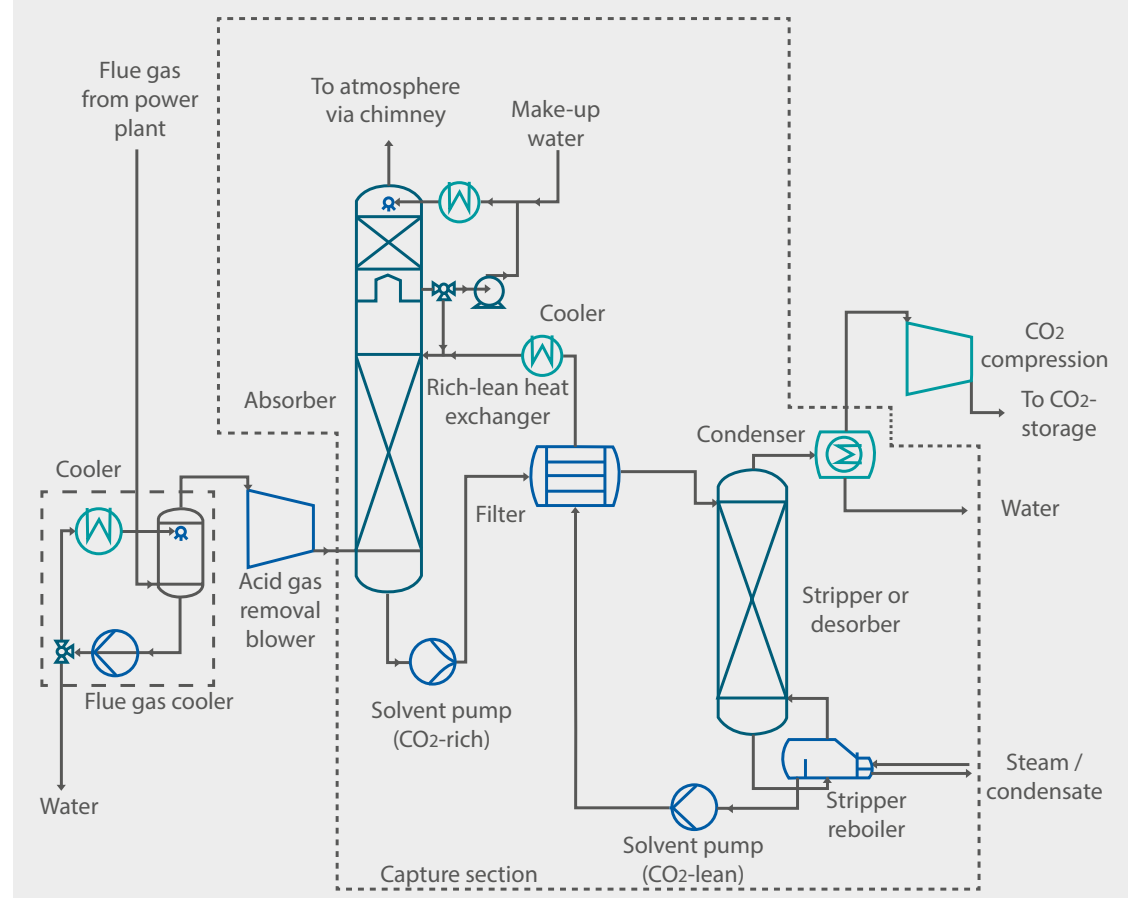
GAS TURBINES AND CCS

In post-combustion capture flue gas from a Combined Cycle Gas Turbine (CCGT) is abated by taking the flue gas from the end of the power plant, cooling it and blowing it upward into an absorption tower. CO₂ is absorbed by a downward flowing liquid (an amine diluted in water), which chemically reacts with the CO₂.

The cleaned flue gas passes through the absorber to vent via a chimney as normal. The CO₂ laden amine from the bottom of the absorber is heated to over 100°C, which releases the CO₂ in a stripper or desorber column. The CO₂ is compressed to 150 Barg and sent to storage. A process sketch is given in Figure 6.

There are many different amines available, with different properties, key ones including the CO₂ absorption rate, CO₂ loading, corrosivity, thermal stability, cost and the energy needed to regenerate the CO₂. Dilute mono-ethanolamine (MEA) was a benchmark solvent for many years, but this has been enhanced over the decades by blends, additives and more complex amines. The basic process layout provides the option of retrofitting CCS without major surgery to the gas turbine (some significant modifications may be required for certain steam turbines), and allows the power station to operate without CCS if necessary. It is essentially two towers and a circulating solvent system.

Figure 6
Process sketch of CO₂ capture from a CCGT



GAS TURBINES AND CCS

Continued

Considering a typical 991MW (net) CCGT power station, adding capture equipment adds £580M to the unabated CCGT capex and reduces power output by 150MW. A breakdown of these costs, which are extracted from the ETI benchmark cases (per Figure 2, page 9 and Figure 3, page 10), is provided in Figure 7 below.

In terms of reducing costs, reductions in capital and energy loss are equally appreciated as every 10% reduction in the capture plant capex or 10%

reduction in the energy penalty of 8.9% points reduces the electricity cost by 1.5 - 2%. One consequence of this is that if low load factor operation is contemplated it will be better to focus on improvements which reduce capex rather than efficiency improvements. Opportunities for cost reduction to amines systems by incremental improvements are outlined in Figure 8 (page 17).

Figure 7

A breakdown of the additional capital costs and power losses of fitting amine capture to a 991MWe (net) CCGT.

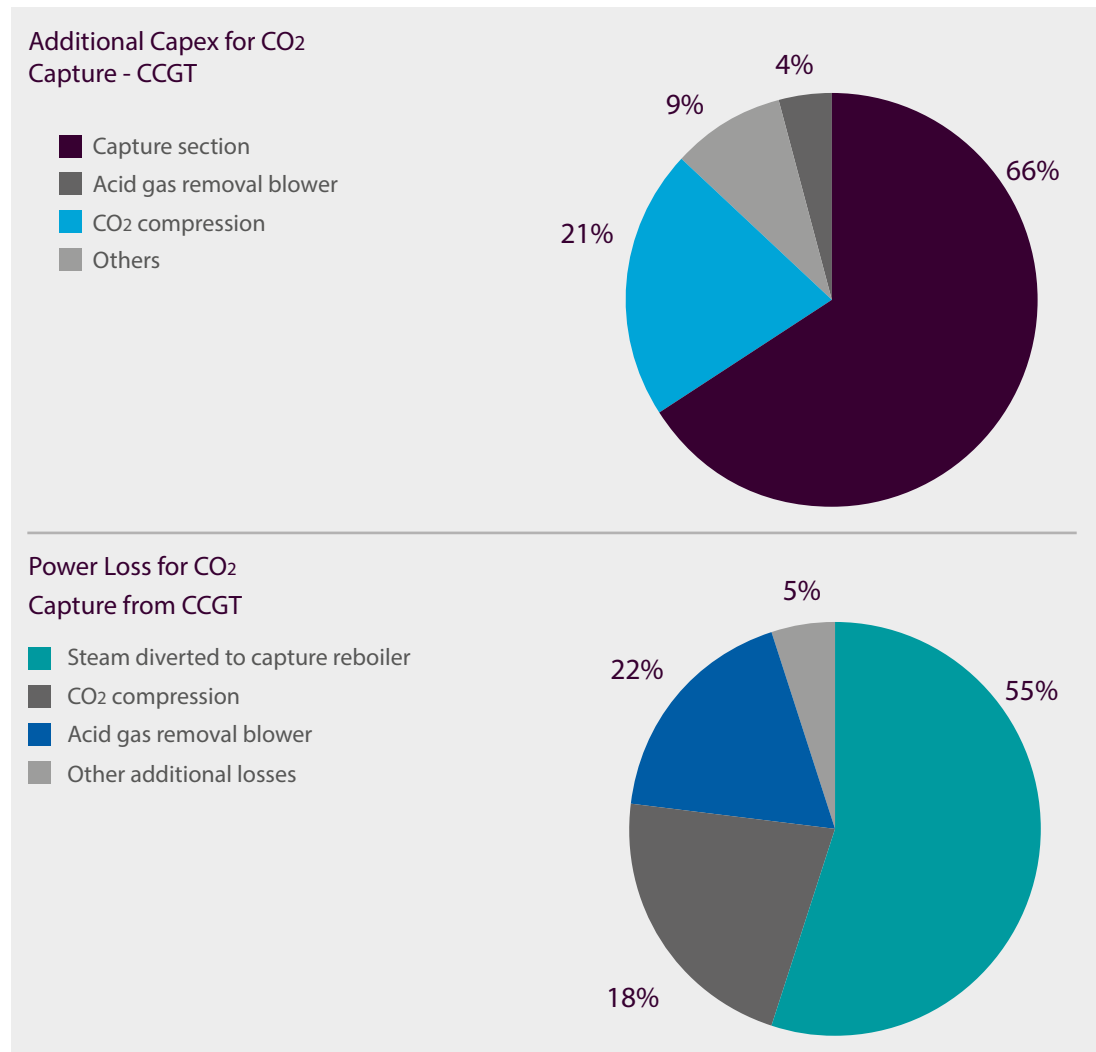


Figure 8

Opportunities for improvements in post combustion amine technology

	Improvement opportunity	Description of potential area
Capital		
Capture section	High	Absorber and stripper - material selection, constructability
	Medium	Stripper - absorbant system optimisation Lower temperature regeneration
CO ₂ Compression	Medium	Novel 'Ramgen' shock wave compressor*
Acid Gas Removal Blower	Low	Low cost item
Energy		
Capture section	High	Stripper reboiler - absorbent system optimisation e.g. bi-phasic systems
CO ₂ compression	Medium - Low	Machine is relatively efficient (65%) Pressurised stripper operation reduces energy requirement
Acid gas removal blower	Medium	Blower and packing technology is mature, high efficiency is needed

*Supported by US government funds, this new compressor type, marketed by Dresser Rand is compact. It co-produces medium quality heat

Capital expenditure is concentrated in the absorber towers, the circulating absorbent network and its utility support system. The tower area is determined by the need for an acceptable upward gas velocity. Cost reduction is a challenge for materials selection, fabrication design and constructability as much as process

design. Designs should minimise process steps on the main absorbing tower, as this will be large equipment due to the low pressure, and incur costly pressure drops in the blowers.

GAS TURBINES AND CCS

Continued

The cost of the stripping tower and auxiliaries are amenable to cost reduction by process improvement. Use of solvents which can regenerate the CO₂ at higher pressure, due to improved thermal and oxidative stability and low corrosivity not only reduce the stripper diameter but also reduce the recompression energy requirement for the CO₂ being despatched to storage. Compression of the CO₂ from 1 Bar to 150 Bar requires 320MJ/te CO₂ of power, compared to the theoretical requirement of 225MJ/te. Compression from 2 Bar to 150 Bar is estimated to require 10% less compression power so the improvement is non-trivial.

Alternatively, chemistry which can regenerate the solvent at low temperature opens the door to lower grade heat sources and possibly fabrication in cheaper materials^{7,8}.

The key opportunity to reduce energy use is focussed on the steam used by the stripper reboiler, as this is diverted from the steam driven electricity generator, and therefore reduces the station's power output. For the design study for the ETI over half the reboiler energy was used regenerating the CO₂, so solvents with lower heats of absorption are therefore highly desirable. However, analysis of solvents with low heats of absorption must be carried out in the context of the whole system energy needs and performance and must not compromise other important features of the solvent such as its solubility, loading, viscosity, and reaction rate in the absorber.

The acid gas removal blower is a low cost item with a high energy use (Figure 7, page 16), so extra expenditure in this area in order to save energy could be beneficial.

In total, the process as flowsheeted for the ETI used between 2.6 and 4.1 times the minimum work energy needed to effect the perfect separation. Many different solvents and packages of solvents have been extensively tested at laboratory, pilot and demonstration scale, and are far superior to the original benchmark "MEA" system.



As far back as 2010, for example piperazine was known to offer 10-20% overall energy savings⁹. It is important that the slow development rate of the CCS market does not close the door on continuing pilot and demonstration scale activity (e.g. at national test centres in Canada, UK, Norway and USA), as many improved systems are not simple "drop-in" changes to their predecessors. Also, in spite of large sums being spent on alternatives to amines, promising options for the post combustion power sector

are still relatively immature. Although CO₂ has been extracted from CCGT flue gas in the past, a replacement project for the UK's Peterhead project is needed to derisk this version of CCS and get a more realistic cost and performance base for use in the power industry.



Chapter Summary

- Post combustion capture technology based on amines is efficient compared to other gas separation technologies, but there are opportunities for further improvements based on absorbent chemistry and properties
- It cannot be assumed that better versions of amines are simple "drop-in" improvements to the initially commercialised ones
- It is tempting to add complexity or new components to increase the efficiency of the design but this may not be cost effective

7 Cheng-Hsiu et al, A Review of CO₂ Capture by Absorption and Adsorption (2012). [online]. Available at http://aaqr.org/vol12_no5_october2012/7_aaqr-12-05-ir-0132_745-769.pdf

8 Oexmann, J. (2010). Minimising the regeneration heat duty of post - combustion CO₂ Capture by wet absorption. p36-43.

9 Rochelle, G. (2010). Concentrated Piperazine - A New Standard Solvent. University of Texas at Austin. [online] Available at http://www.ieaghg.org/docs/General_Docs

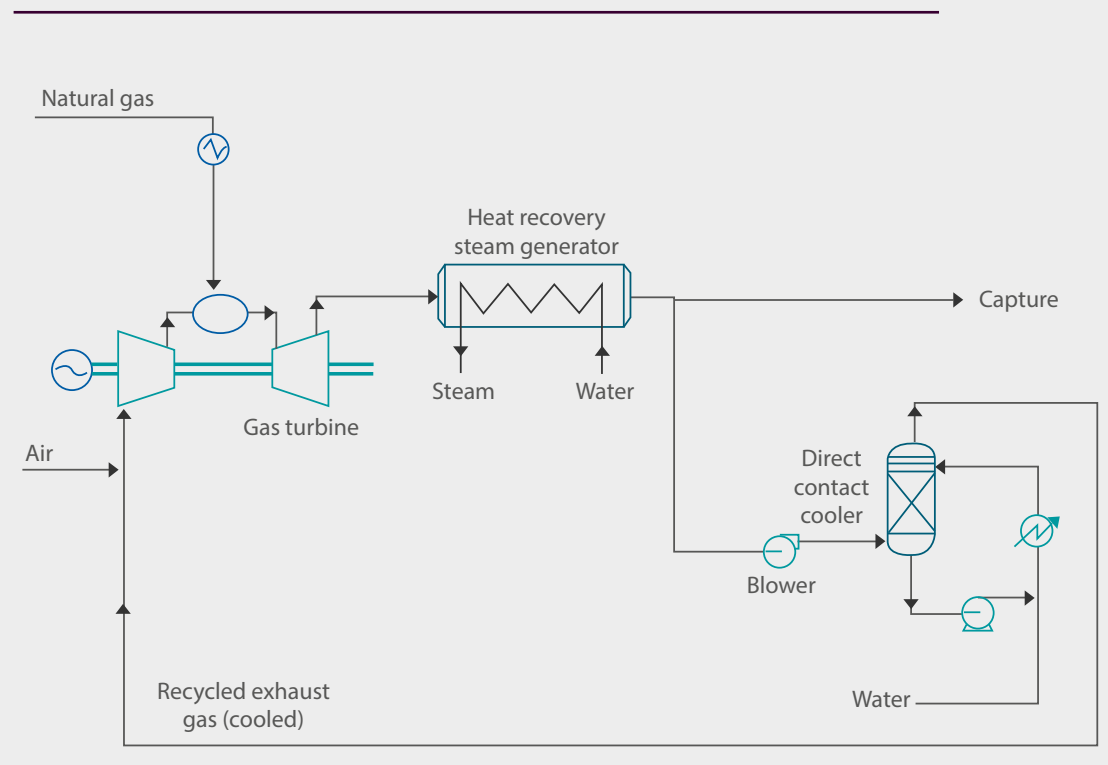
CCGTs WITH EXHAUST GAS RECYCLE (EGR)

The optimisation of amines with CCGTs is limited by the low concentration of CO₂ in the flue gas (an issue even more acutely experienced when trying to remove CO₂ from air^{10,11}).

One way of enriching the flue gas CO₂ concentration in a CCGT flue gas is to replace air normally fed to the gas turbine with cooled flue gas from downstream of the steam generator,

which is relatively rich in CO₂, as shown in Figure 9 below. The flue gas is cooled as much as practicable because warm air derates the gas turbine.

Figure 9
Fitting exhaust gas recycle to a CCGT with CCS fitted



Recycle rates of 35% of the flue gas have been demonstrated in a GE¹² combustion system, increasing the CO₂ concentration at the absorber inlet from 4% to 7%. Alstom (whose power business is now owned by GE) have also undertaken practical work in this area¹³ reporting reductions in NO_x as a co-benefit. This increases the quantity of CO₂ absorbed by the solvent and reduces the volumetric gas flow to the capture plant to c.65% of the non EGR case, reducing the acid gas blower size and power loss, and the size of the absorber and its auxiliaries.

In the case of the ETI benchmarks, the overall efficiency improvement from adding EGR is modest (less than 1%), but total capital costs reduce by a healthy 7%. Combined, these reduce the cost of electricity by 3% at full load and 8% as the plant load is reduced to 40%. Although EGR is more incremental than breakthrough as a plant improvement, most alternative novel technologies offering similar value carry higher risk.



Chapter Summary

- EGR is a useful add-on technique for amine technology, and may improve other capture system performance by a greater margin, especially when the gas turbine is run at low load
- EGR could be demonstrated independently from a capture plant and has been supported by gas turbine vendors such as Alstom and GE.
- EGR lowers the capital intensity of CCS and reduces constraints posed by other emissions such as NO_x. It is well researched, and has a relatively low risk

10 Brandani, S. (2012) Carbon Dioxide Capture from Air: A simple Analysis. Vol 23, No 2 &3. [online] Available at <http://eae.sagepub.com/content/23/2-3/319>

11 Gibbins, J. (2015) Negative emissions for climate change stabilisation & the role of CO₂ geological storage. Université Pierre et Marie Curie.

12 Elkady, M. A., Evulet, A. (2009) Application of Exhaust Gas Recirculation in a DLN F-Class Combustion System for Post-combustion Carbon Capture.

13 Carroni, Sander. (2011) Flue Gas Recirculation in a Gas Turbine.

OTHER (NON-AMINE) POST COMBUSTION TECHNOLOGIES

A number of different alternatives to amine circulation technologies are being tested at pilot plant scale. These include use of enzymes, fuel cells, membranes, alternative solvents and various adsorption techniques (on solids). Each of these could claim theoretical advantages over liquid amine systems but these advantages are susceptible to being eroded in the journey towards commercialisation.

Solid adsorbents can have higher CO₂ loadings and lower heats of adsorption than liquid amines and have huge surface areas capable of fast reactions, so in theory they should be able to offer competitive performance. Further, they avoid the need to handle toxic liquids, have lower corrosivity issues and use equipment in use today.

One example of an adsorption technology is “temperature swing adsorption” (TSA). In this process the flue gas is compressed (as per the amine “acid gas removal blower”), cooled and passed over the adsorbent and CO₂ is preferentially adsorbed compared to the other flue gas components (O₂, N₂, H₂O). The adsorbent can be in various forms such as pellets (in a bed) or formed into a monolith and housed in a rotary bed as shown in figure 10 on page 23.

The cleaned flue gas is vented and the solid which has absorbed the CO₂ is regenerated separately by heating it, the CO₂ released being sent for pressurisation and storage. The hot, clean adsorbent is cooled and reused. The adsorbents properties dictate the design and economics, for example

> Capacity is a measure of how much CO₂ can be adsorbed per unit mass of adsorbent. The higher this is, the lower the amount of adsorbent needed and therefore the smaller the equipment size and compression loss. If the adsorbent can be loaded with CO₂, regenerated and cooled quickly, the adsorbent can be re-used (“cycled”) quickly and again less adsorbent is needed, leading to smaller beds or shorter monoliths.

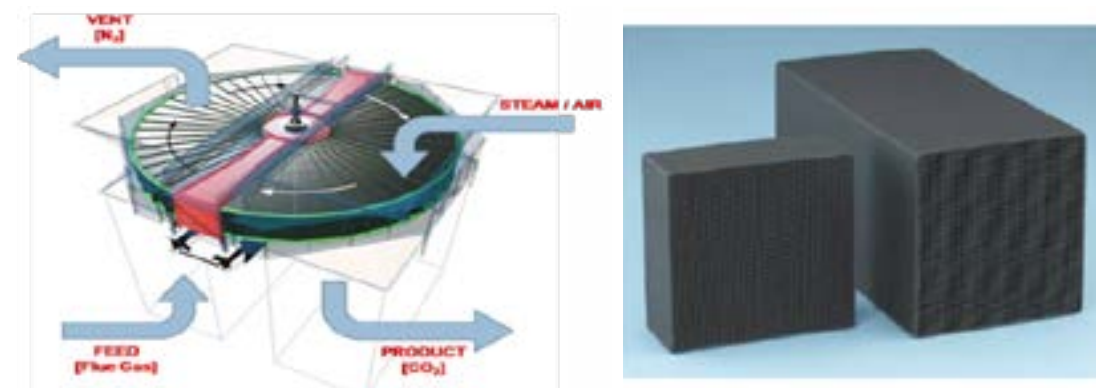
> Selectivity to CO₂ – lower selectivities mean that the regenerated CO₂ contains N₂, O₂

etc and consequently in order to meet the required CO₂ purity specification additional recycles, vents or other steps may be needed. These use more capital and energy (especially pressure drop).

> Heat of Regeneration – this needs to heat up the solid bed, desorb the CO₂ and if necessary raise the adsorbent temperature even higher. As with the liquid amine, a low heat of desorption doesn’t automatically mean a good process as heating the solid will use up more heat, especially if the loading is low.

Activated carbon is cheap and environmentally acceptable but it has a relatively low CO₂ loading even in monolithic format¹⁴. It has a lower CO₂ desorption energy requirement than for amine (40kJ/mol rather than 85kJ/mol), but the low loading compromises this benefit because the heat required to raise the activated carbon from adsorption temperature to regeneration temperature (100°C+) is greater than the heat needed to desorb the CO₂. Reusing the heat from the hot bed is not as straightforward as the “rich-lean” transfer exchanger in the amine equivalent in Figure 6 (page15), and can involve cooling with air, incurring additional compression losses. The low selectivity of the simple carbons ETI has tested¹⁴ results in the need for purges and recycles. Small deficiencies at key process steps can erode the benefits of adsorption that would be expected from a superficial assessment. Testing showed “Chemisorbants” adsorbents which react chemically with CO₂ rather than forming weaker physical bonds - for example alkali oxides, carbonates, supported amines) are well-suited to lean gases and the Metal Organic Frameworks (MOFs) arguably appear to offer an even better performance, although these are still in development and their production cost may be high. In spite of the gulf between carbon and these new materials, no large scale/long term testing has been carried out.

Figure 10
A rotary bed and close up of a monolith



Chapter Summary

- Many non-amine technologies have been piloted and promise better economics than amines. However, during engineering and development expected benefits can be eroded, as most processing steps involving low pressure gases will cause pressure drop (expend blower power) and need large, costly equipment
- Adsorbents can be non-toxic solids and the associated equipment is familiar to some station operators
- With improved materials and process development, adsorption should compete with amine systems. Each new family of materials will probably need its own tailored process

OXY-FUEL SUPERCRITICAL CO₂

As an alternative to fitting a gas fuelled CCGT with post combustion technology, NET Power, a US company, is developing a new power cycle which supplies oxygen from an Air Separation Unit (ASU) and natural gas to a high pressure combustor (300 Barg) and expands the CO₂ and water produced through a gas turbine to 30 Barg. The water produced by combustion is condensed, and the CO₂ which remains is pressurised to a supercritical state, pumped back to 300 Barg and sent back to the combustor where it is used both to recycle turbine exhaust heat within the system and for controlling combustor temperatures. As shown in Figure 11 below, the CO₂ is used as the working fluid, and there is no steam cycle. NET Power claim this scheme offers carbon capture at the same cost as a conventional power station without carbon capture.

If NET Power realise their twin “targets” of 58.9%¹⁵ LHV efficiency at the same capital cost as current CCGTs, the technology would enter the power market and offer carbon capture at low extra cost to the consumer, comprising only the costs of CO₂ transportation and storage. If these claims cannot be realised, and the levelised costs of power from the NET Power process are greater than an unabated CCGT, the technology may not gain the rapid commercialisation offered by the open power market. Instead, it could compete in the CCS and Enhanced Oil Recovery markets with other new technologies, some of which are retrofittable to existing power stations. Modelling by the ETI,

without the benefit of vendor information, but estimating all process losses, could achieve 53% LHV efficiency. NET Power claim this is the base level performance achievable using publically available information, without the benefit of several years of development and optimisation experience with their cycle.

Process modelling showed:

- For an idealised cycle (100% methane feed, no pressure drops etc.), NET Power's efficiency claims could be met quite comfortably.
- A susceptibility of efficiency to inerts, and reliance on state of the art equipment performance including heat exchangers.
- Upside potential from:
 - a) having cold cooling water available
 - b) improvements to metallurgy allowing higher temperatures and pressures in the heat exchange train

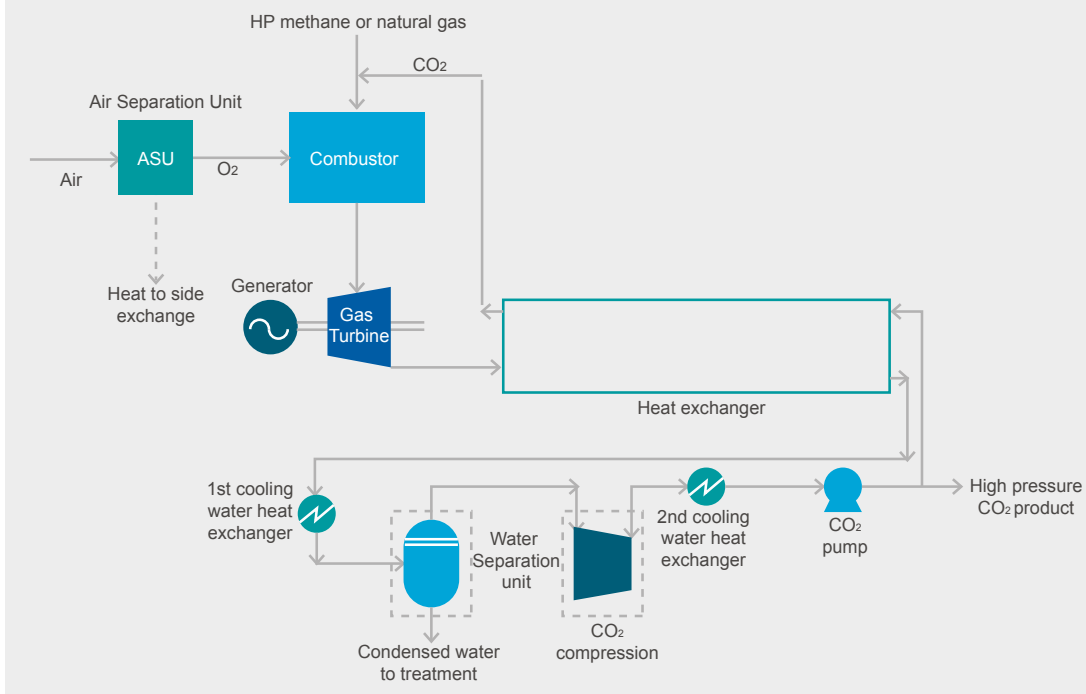
c) the ability to upgrade low-grade heat to power at high efficiency, if a low cost heat supply is available from other sources or auxiliary conventional generation.

Energy system modelling showed that if NET Power meet their targets, the technology could significantly displace others by 2040 and increases deployment of CCS at the expense of other low carbon options. Even if lower performance is achieved in its early years (e.g. that in “Oxy-Combustion Turbine Power Plants, IEAGHG Report 2015/5) the technology could still be deployed in the UK.

A 50MWth (25MWe) demonstration plant is under construction in Texas, testing the full cycle including a new combustor and turbine design and use of modern high nickel alloys. The control scheme for the plant will also be tested for the first time.

NET Power are targeting deployment of a first commercial scale plant (300MWe) by 2020.

Figure 11
The NET Power Process - simplified



¹⁵ Allam, R.J., Palmer, M.R., Brown, W.G. High efficiency and low cost of electricity generation from fossil fuels while eliminating atmospheric emissions, including carbon dioxide.



Chapter Summary

- If they meet their targets, NET Power will license a game changing technology. It has no solvent toxicity to manage, an extremely small footprint, and an impactful efficiency improvement. It could enter the CCS market with no subsidy requirement
- The technology is still immature. It faces several challenges on equipment design and operation, but testing at scale is under way. It may be several years before NET Power can fully demonstrate an attractive package to the market

COAL AND BIOMASS

PULVERISED COAL

Although coal has a higher carbon content than gas, coal CCS could be retained for portfolio reasons, as it enjoys low variable costs and offers security of supply. Its environmental challenge goes beyond CO₂ and additional constraints (e.g. SO_x and NO_x emissions) are expected in the future. As noted earlier, the high capital costs increase the risks of such investments and the low load economics will be poor.

For pulverised coal plants the flue gas is richer in CO₂ (14% in contrast to 4% for the CCGT), making recovery easier, as increased concentrations increase the rate and loading capability of the solvent which reduces both capital and operating costs per tonne CO₂ captured. The flue gas also contains less oxygen (2% in contrast with 11% for the CCGT) causing less degradation of solvents. Hence coal has lower “acid gas removal” blower costs.

Of course coal is more carbon intensive than gas (per MJ) and the CCGT is more efficient than the supercritical boiler, resulting in CO₂ creation rates in abated PC plants being 2.3 times that of abated CCGT per MWh of clean electricity produced. One way of reducing carbon intensity

is to co-combust biomass which has been trialled for many years. The Drax plant in the UK has successfully retrofitted coal boilers to burn 100% biomass at scale, and has developed infrastructure to import biomass into the UK. The capture of CO₂ from boilers firing biomass seems a straightforward step, offering “negative emission” performance.

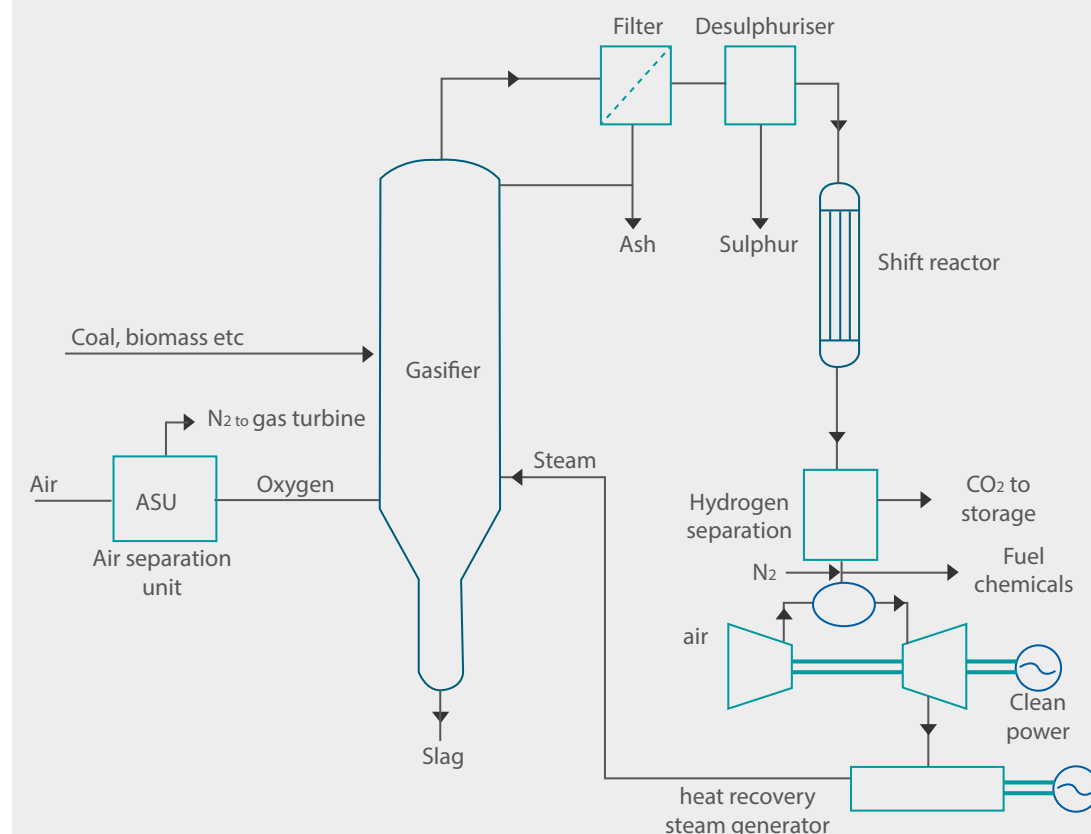
As in the case for CCGTs, there are opportunities to incrementally improve the amine process. Several companies have demonstrated their proprietary capture technologies at reasonable scale (MHI, Siemens and Alstom etc).

Following the 2014 start-up of the SaskPower coal plant in Canada, the technology is proven, and costs should come down due to scale, sharing and risk reduction. While coal may or may not take a role in low carbon power production in the UK, we must expect major coal using countries like China to adopt the technology. It may be deployed on biomass plants in the UK in the future.



PRE-COMBUSTION COAL AND BIOMASS - INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

Figure 12
An Integrated Gasifier Combined Cycle (IGCC)



Pre-combustion technology handles low-grade fuels (lignite, biomass, heavy oils) yet has a good environmental performance, and offers the potential to co-produce power, chemicals and flexible low carbon fuels (e.g. hydrogen). A sketch is shown in figure 12.

The technology is flexible in terms of co-firing waste, biomass and coal, but is not responsive in terms of meeting daily load changes. As shown on page 29 this problem can be overcome by storage of the H₂ produced in salt caverns¹⁶. China has built several (without CCS), but uptake

for power outside the Far East has been slow, as the technology is more demanding to operate, had poor reliability early in its development and more recently severe cost overruns in projects under construction. There is also a significant range in the capital cost estimates for IGCC plants, given the limited experience of building them.

PRE-COMBUSTION COAL AND BIOMASS - INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

Continued

In Europe and more particularly in the US, significant research development and demonstration has improved the overall costs and efficiency of IGCC with capture. Much of this work is nothing to do with capture but improving the process and key machinery, such as the H₂ turbines. Like pulverised coal plant the intrinsic generator efficiency is improving as new alloys are deployed, reducing the CO₂ load, but the market has greater confidence in PC plants.

The largest potential gains can be found from savings in separation of H₂ and CO₂ by membranes. For example the European Cachet II project¹⁷ claims over 2% point energy savings from use of palladium membranes, but these have not yet been commercialised. The ETI contracted Costain to engineer a process

which instead used cryogenic cooling to do this separation, which saved just under 2% in energy penalty without use of novel materials.

Although the high operating pressure and high CO₂ partial pressures set the stage for cheap capture, these benefits are offset by losses in other areas of the process, that are not easy to mitigate.

OXY-FUELLED COAL COMBUSTION

In this technology pulverised coal is combusted with pure oxygen from an air separation unit (ASU). The technology can be retrofitted to existing air-fired boilers, making this a retrofit option. Use of oxygen rather than air means that the flue gas is rich in CO₂, making separation relatively easy. As with the NET Power process (which also has a coal burning version based on pre-combustion) this cheap and energy efficient CO₂ separation comes with an expensive and energy intensive air separation unit to generate oxygen. Overall, the economics of the process is similar to other coal CCS processes, but it has advantages in terms of flexibility, for example at night it can use low cost power to focus on O₂ production, which can be stored for daytime use. The technology has not been demonstrated at full scale, but has been extensively tested at 20-40MW scale, and uses designs similar to conventional boilers. The White Rose project in the UK would have been the first commercial plant but the funding competition has been cancelled.

17 Forsyth, J., Song, B. (2013) Cachet 2: Carbon Capture and Hydrogen Production with Membranes. Energy Procedia 37.



Chapter Summary

- Abatement costs are slightly higher for pulverised coal than for gas on a “per MWh of low carbon power” basis, even though abatement cost per tonne of CO₂ is lower (£45/te c.f.£85/te)
- Combustion of biomass in coal boilers is proven, and a supply chain has been established
- Innovation and demonstration units show continuous improvement to pre-combustion technologies, and the technology is being demonstrated at Kemper County in the USA, commissioning in 2016. Cost overruns in this, and other contemporary IGCC construction projects, may detract private investors until the technology is further derisked
- Pre-combustion technology is flexible in its fuel source offers hydrogen to the refining, heat & fuel markets and, when combined with hydrogen storage, can respond effectively to daily changes in power and heat demand

FLEXIBILITY

Gas fired power stations have successfully operated in base load, load following and “peaking” roles, usually in competition with coal units. By way of example, Figure 13 (page 30) shows the UK’s power demand over 19 days in April 2015, using 5-minute data from Gridwatch¹⁸. The demand line is shown at the top of the chart in red. The daily cycling is satisfied by constant operation of nuclear plants, intermittent power supplies from our growing wind fleet, and supply by coal and gas power stations, which are currently not fitted with CCS technology. A portion of this demand, between 10,000 MW and 22,000 MW is there throughout the month and could be met by running CCS plants flat out, but there is clearly a portion of around 40% of the total capacity which needs the fossil fleet (or some very large energy storage system) to respond to varying loads. Fitting this with CCS abatement technology economically is more challenging, due to higher capital costs per MWh (due to lower average output) and additional variable costs due to frequent start-ups, running at suboptimal efficiency at low rates and high maintenance costs associated

with this type of operation. Nevertheless, system level modelling carried out at the ETI shows that abatement of the responsive sector of the power fleet is on the lowest cost pathway to meeting our climate change targets by 2050.

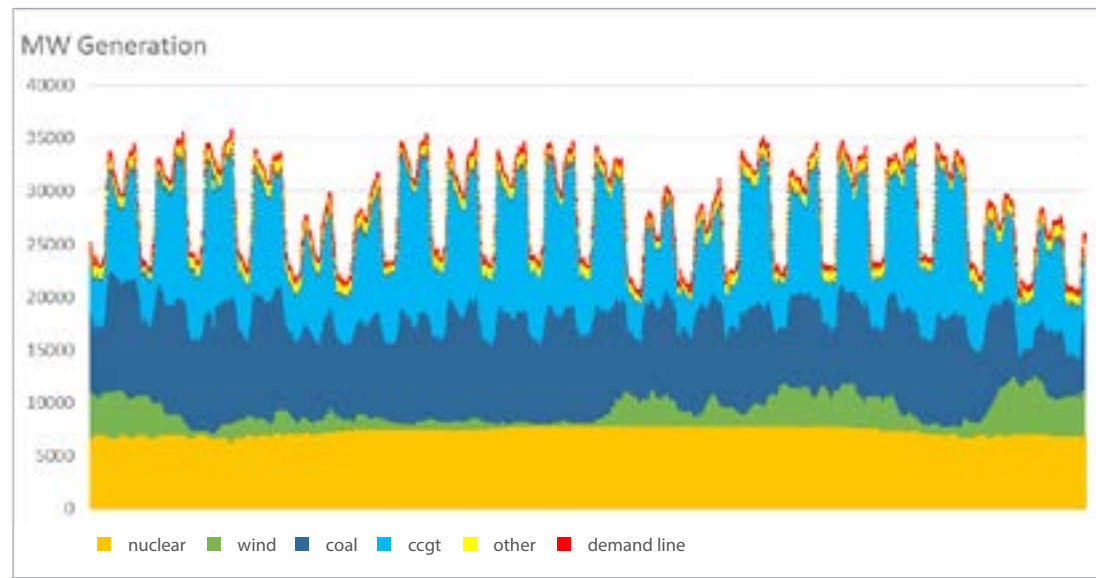
Both nuclear and wind power are deployed or “despatched” when available as they have low variable costs. Both these fleets are expected to grow between now and 2030 in order to help the UK meet its climate change targets. Consequently a shrinking fossil fleet will need to retain agility, good turndown and stop/start characteristics into the 2030s and beyond.

18 G.B National Grid Status. [online]. Available at <http://www.gridwatch.templar.co.uk/>

FLEXIBILITY

Continued

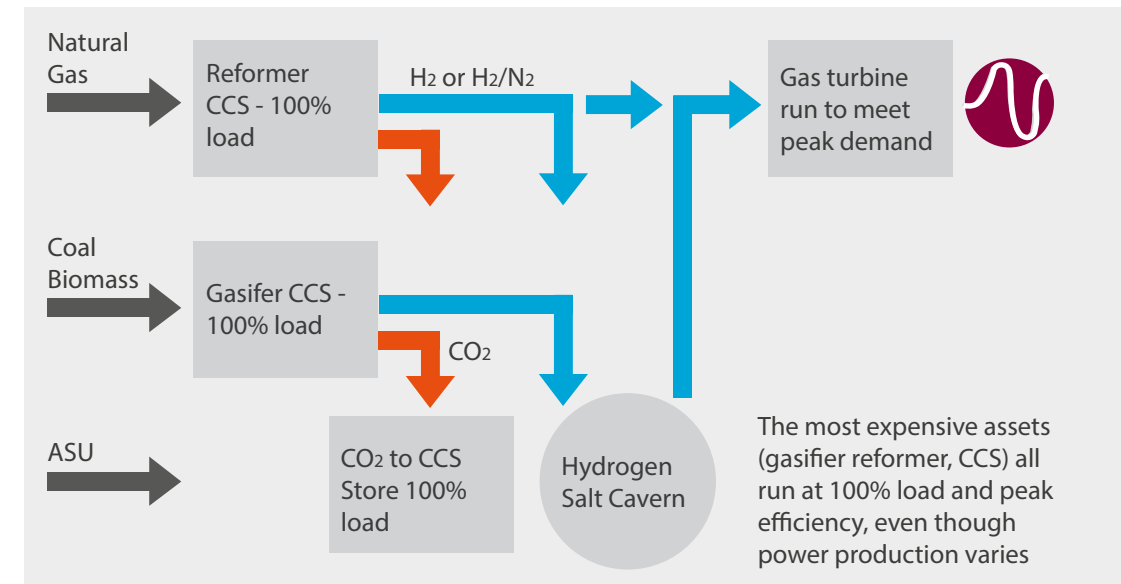
Figure 13
19 days of the UK's power demand profile, April 2015



Peak ramp rates in the April period exceeded 120MW/min, and the required increase in duty is around 7000MW, requiring about 20 large CCGTs. The combined ramp rate possible with these is more than sufficient for today's needs. Looking out to the future, more nuclear and renewables capacity may squeeze the amount of "base load" (high load factor) operation available for fossil generation. The latest gas turbines (e.g. GE, Siemens) are rated at 500MW and can ramp at 35-50 MW/min, much faster than most current UK machines and so will be effective in the marketplace. Despatch studies by the ETI have shown that although fitting CCS slows down CCGT response times, the ability of abated plants when running to follow actual market demands is not significantly impaired. The ability of the capture plant to shut down or start up quickly (or "park" economically) will be important, and independent operation of the generator is an advantage should CCS be shut down for any reason.

One way of minimising the cost of building and operating CCS abated power plants at low load is shown in Figure 14, page 31. In this scheme the main investment in CO₂ capture, transportation and storage runs at full load all the time and feeds H₂ storage in salt caverns. These pressurise during periods of low power demand and depressurise to generate electricity at peak demand times.

Figure 14
A plant configuration which minimises cost of low load operation of CCS equipment



Conclusions

The ETI has evaluated capture technologies based on process, economic and system level modelling. In the early years of CCS, costs will reduce quickly due to economies of scale, sharing infrastructure and risk reduction. Sask Power claim a subsequent capture plant will be 30% cheaper than the first, including savings from lower research costs¹⁹. Incremental improvements to demonstrated plant is to be expected. Deeper technology improvements will not be as impactful as reducing costs by deployment. Combined with the low growth rate of CCS and the absence today of a commercially ready game-changer this means amines and pre-combustion technologies will continue to be the technology of choice in power production for several years.

Key demonstration projects are either complete or are under way and there may be temporary technology lock-in, as the financial markets will be reluctant to invest in unproven capture technology because CCS projects are already perceived as high risk. After 2030 innovation should play an increasing and welcome role in cost reduction.

It is important that technologies offering breakthrough performance are funded through to demonstration level so they can enter the market when other aspects of risk have been reduced.

By the mid-2030s CCS plants may have to respond to daily demand changes, and therefore operate at lower load. Technologies which reduce capital costs may be more attractive than energy saving initiatives. In ETI system modelling, new investments for this market will favour gas turbines due to cost and biomass gasification due to the value of negative emissions.

¹⁹ Monea, M. (2015). Mike Monea on Carbon Capture and Storage. Financial Review. Available at <http://www.afr.com/business/energy/saskpowers-mike-monea-on-carbon-capture-and-storage-20150519-gh4q8d>

Appendix

Summary of economic indices and data used in the Figures

1. Figure 1: Uses 2014 undiscounted costs. Capital cost are +/-40%
2. Figure 2 : Thermodynamic data from NIST chemistry web-book 2008
3. Figure 3&7: 2010 costs. Discounting at 10%, with a 20 year lifetime for gas plant and 30 years for coal plant. Costs are for mature "nth of a kind" plant and include a contingency of 25%. Costs are +/- 40%. The plants run with an 85% load factor. Gas at £265/te, coal at £65/te and CO₂ at £0/te.
4. Figure 5: Levelised costs are in UK£ 2013, capital costs are +/- 40% (EPC x1.4), discount rates are adjusted for risk (range 9-16%). Gas £24/ MWht and CO₂ emission £31/te. All plants other than first demonstration plant are 860MW net output.

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Further reading:


>The role of hydrogen in a low carbon energy system

>A picture of CO₂ Storage in the UK

>Potential for CCS in the UK

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