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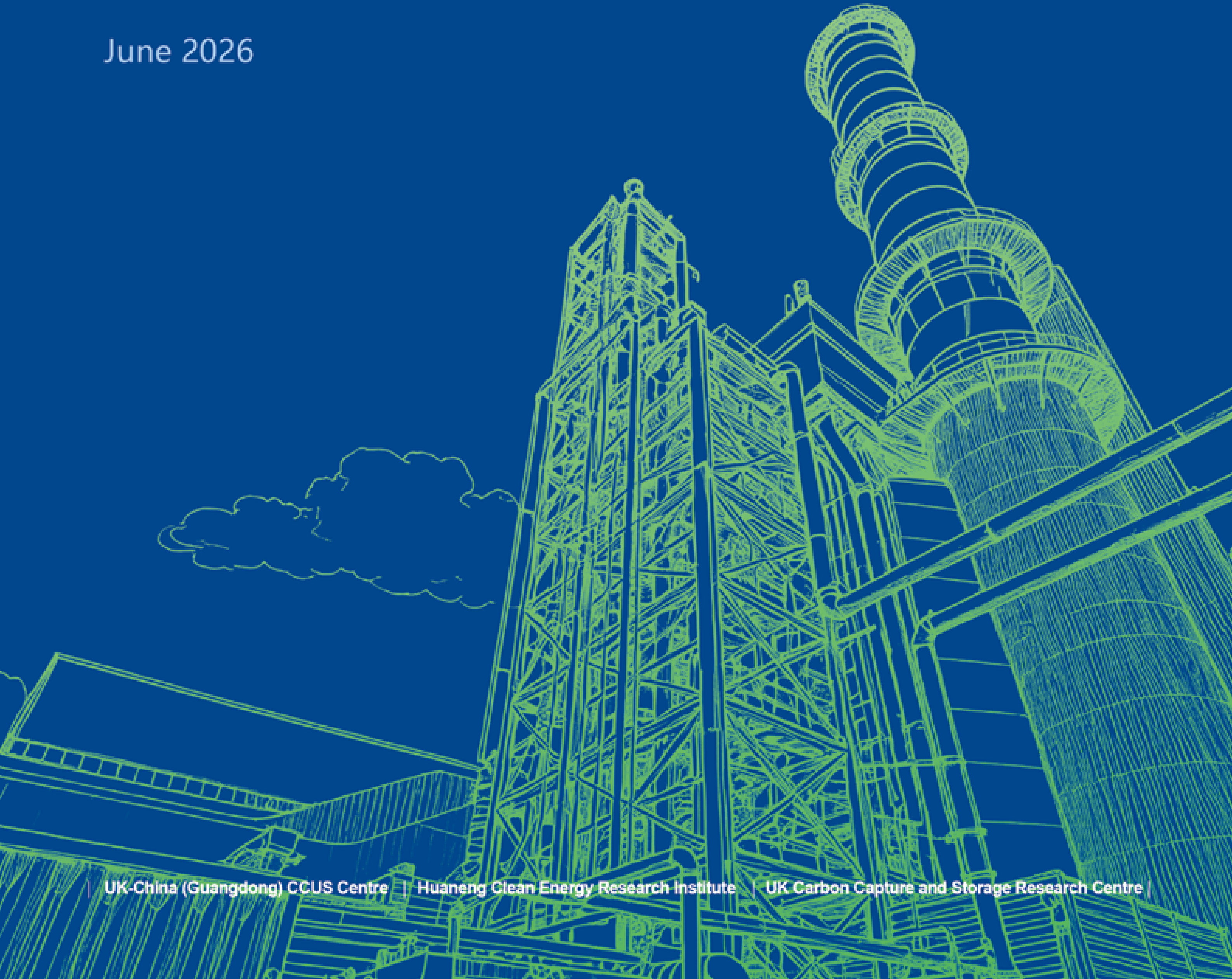
Towards Net-Zero Gas Power:

CO_2 Capture in NGCC Plants – Status, Challenges, and Outlook

June 2026



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Acknowledgement

This report was prepared under the “Road to Net Zero – UK-China Partnership Initiative on Carbon Capture, Utilisation, and Storage (CCUS)” project, funded by the UK Foreign, Commonwealth and Development Office (FCDO) through the British Embassy Beijing. The authors gratefully acknowledge the financial support of FCDO and the collaborative framework that made this work possible.

On 17 March 2025, China’s National Energy Administration (NEA) and the UK’s Department for Energy Security and Net Zero (DESNZ) held the Eighth China–UK Energy Dialogue in Beijing, jointly signing the Memorandum of Understanding on the China–UK Clean Energy Partnership. The work presented in this report represents a CCUS-specific deliverable under this bilateral cooperation framework.

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Executive Summary

Natural Gas Combined Cycle (NGCC) power plants play a pivotal role in the global energy transition, providing essential flexibility and reliability to grids with increasing shares of variable renewable energy. However, their continued operation is only compatible with net-zero climate goals if their CO_2 emissions are effectively eliminated. This report assesses the status, challenges, and pathways for deploying carbon capture, usage, and storage (CCUS) on NGCC plants.

While hydrogen blending represents a potential long-term solution, amine-based post-combustion capture (PCC) remains the only technologically mature and scalable option for near-term NGCC decarbonisation. Alternative technologies, such as the Allam Cycle or solid adsorbents, are currently unsuitable for large-scale application due to technical immaturity or limitations with low CO_2 concentration flue gases. Despite the technical feasibility demonstrated in Front-End Engineering Design (FEED) studies, no commercial-scale NGCC+PCC plant is yet in operation, leaving critical uncertainties regarding long-term performance and costs.

The assessment reveals several critical insights regarding the economic and technical landscape for NGCC+CCS:

Technology & Economics:	Amine-based PCC is the sole ready pathway, but costs are highly sensitive. Capture costs vary significantly depending on the plant load factor, with recent estimates ranging from approximately \$80/t CO_2 at high load factors to over \$212/t CO_2 at low load factors. Furthermore, macroeconomic conditions from 2020 to 2024 drove a significant increase in unit capture costs due to inflation and rising interest rates.
Capture Rates:	Industry expectations for capture rates are evolving. Research demonstrates that achieving ~100% “added CO_2” capture (returning flue gas to ambient CO_2 levels) is feasible, moving beyond the traditional 90-95% benchmark.
Operational Flexibility:	As NGCC plants in renewable-heavy grids must cycle frequently, the FOCUSS project demonstrates that solvent storage systems can maintain high capture rates during start-up, shutdown, and transient loads.
Solvent Performance:	Comparative analyses suggest marginal performance differences between advanced solvents and benchmark MEA. The greater differentiator and risk lie in long-term stability and degradation management, where early projects have seen costs exceed forecasts.

The strategic importance of NGCC+CCUS is underscored by the parallel trajectories of China and the UK. China's gas power capacity is projected to reach 200-400 GW by 2030. The Huaneng Yangpu NGCC Carbon Capture Pilot Unit (~2,000 t/a), operational since 2023, represents China's first international testing platform for natural gas-fired CO_2 capture, demonstrating the integration of carbon capture with flexible peak-shaving operations. The UK, targeting a net-zero power system by 2035, is advancing flagship projects like Net Zero Teesside. In both contexts, decarbonised gas power is a system-critical asset for grid stability.

To accelerate the deployment of reliable, high-performance, and cost-effective NGCC+CCS, the report recommends a focus on five strategic priorities:

1.Validate through Long-Duration Testing:	Operate integrated pilot projects for a minimum of two years to gather reliable data on solvent longevity and operational costs.
2.Engineer for Flexibility:	Implement advanced solvent management and control strategies, such as solvent storage, to guarantee high capture performance during all operational modes.
3.Adopt 95~100% Capture Rate Standards:	New projects should target a minimum capture rate of 95%, with a design goal of ~100% "added CO_2" capture to align with net-zero emission pathways.
4.Drive Down Capital Expenditure:	Pursue cost reduction through modularisation, optimised heat integration, and right-sizing for flexible duty cycles.
5.Enhance Policy and Market Support for Early Deployment:	Until economies of scale drive down costs, public support is critical. Governments and regulators should provide targeted financial mechanisms (e.g., grants, low-cost loans, or contracts-for-difference for captured CO_2) and strengthen carbon market signals to create a viable revenue stream and de-risk early commercial NGCC+CCS investments.

In conclusion, deploying CCUS on NGCC plants transcends an end-of-pipe abatement tactic. It represents a fundamental system-level investment in energy security and transition resilience. Through sustained collaboration, targeted innovation, and enabling policies, NGCC+CCUS can fulfil its crucial role as a bridge to a secure, reliable, and net-zero energy future.

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1 Introduction

The global energy system is undergoing a profound transition towards decarbonisation.

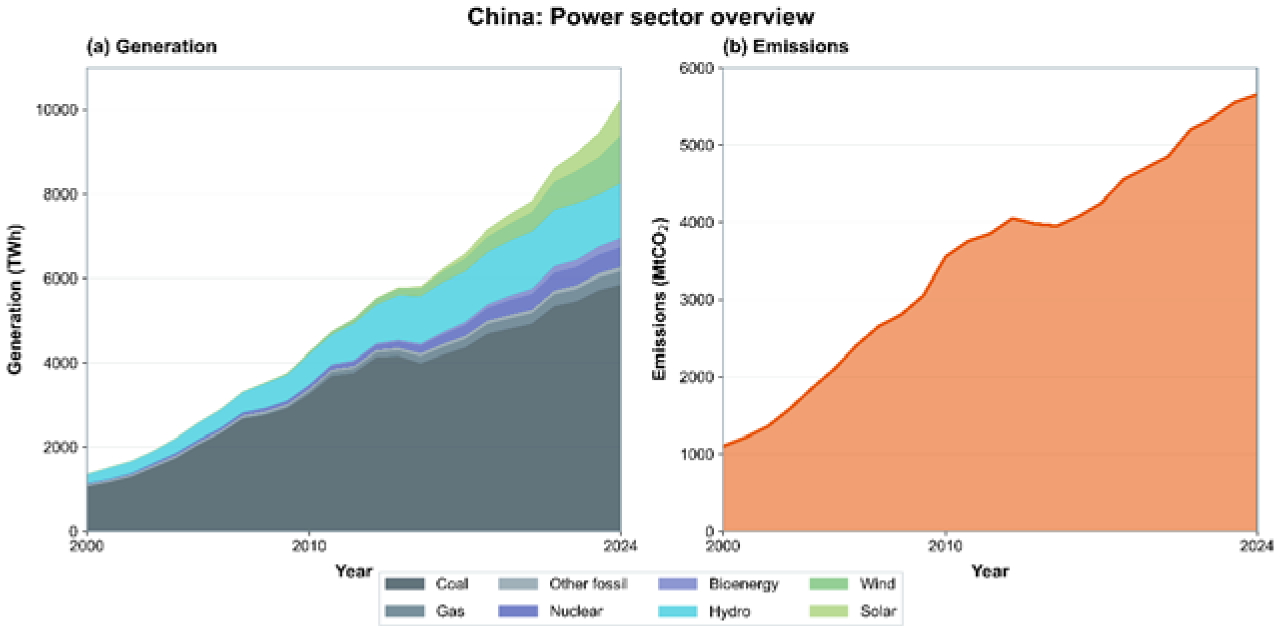
Within this shift, natural gas-fired power generation, particularly Natural Gas Combined Cycle plants, assumes a critical dual role: serving as a cleaner alternative to coal and, more importantly, as an essential flexibility provider for integrating variable renewable energy sources. However, the climate benefits of gas power are relative. A typical NGCC plant still emits approximately 350-450 kg of CO_2 per MWh, about 40-50% of the emissions from a comparable coal-fired plant[1]. Therefore, as gas power expands to support deeper decarbonisation, addressing its own carbon footprint becomes an urgent imperative.

This expansion is particularly evident in China.

In 2024, China's natural gas consumption grew by **7.3% year-on-year**, accounting for **8.8% of primary energy use**. Gas consumption for power generation rose by 9.5%, representing 18% of total gas use, with annual additions to gas-fired power capacity hitting a record high[2]. NGCC plants are increasingly recognised as a **"crucial supporting force in building a new-type power system,"** vital for peak-shaving and ensuring grid reliability. Projections suggest China's gas power capacity will reach **200-400 GW by 2030**, potentially retaining **200-300 GW even by 2060**[3]. Consequently, deploying CCUS on these assets is not merely an option but a necessary and urgent task for the deep decarbonisation of China's power sector, representing a substantial potential market for the technology.

The experience of the UK provides a compelling parallel.

In 2024, the UK achieved a historic milestone: renewables supplied 50.4% of electricity, while fossil generation fell to a record low of 31.8%[4]. With coal fully phased out by September 2024, virtually all remaining fossil generation is gas-fired, constituting 30.4% of total electricity supply4. Recognising that flexibility cannot come at the cost of long-term climate goals, the UK government has committed to a "net zero carbon power system by 2035" and explicitly identifies decarbonised gas—via **CCUS and hydrogen blending**—as a critical transitional asset[5]. This demonstrates that developing low- or zero-carbon gas power technologies is a strategic priority for any nation seeking a secure and reliable transition to a renewables-dominated grid.



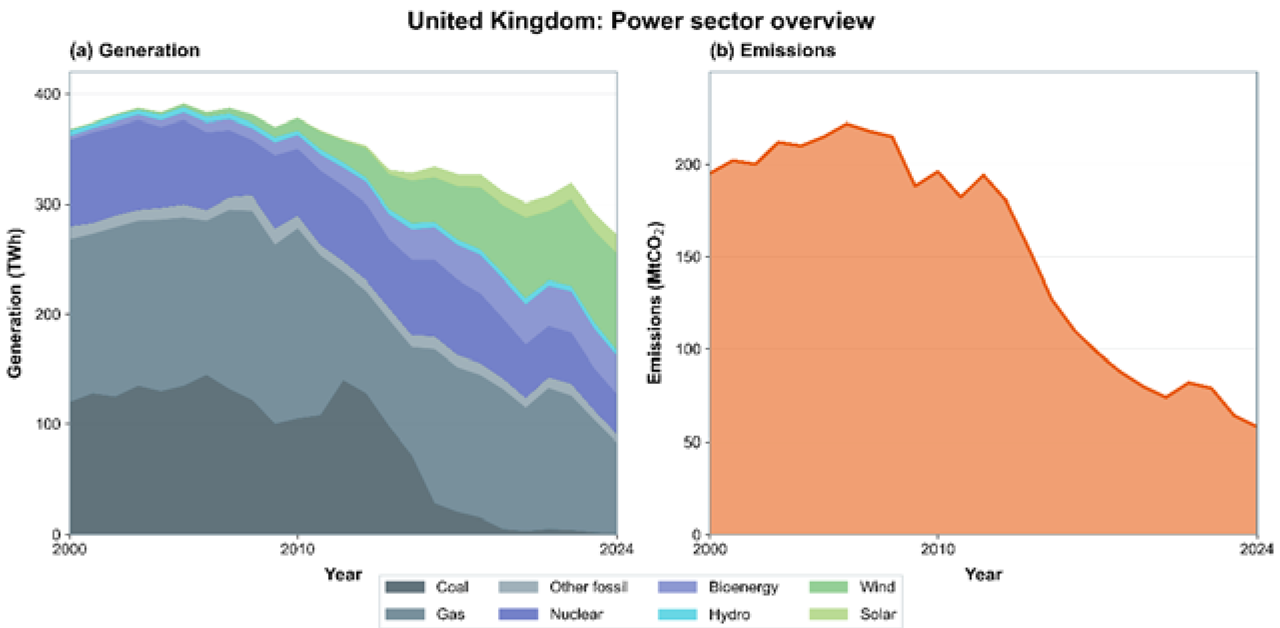


Fig. 1 China and UK electricity generation mix in 2024[6,7]. In China, gas-fired generation reached approximately 303 TWh in 2024, representing ~3.2% share of the country's total electricity output[8]. In the UK, gas generation amounted to around 84 TWh, accounting for over 30% of national electricity supply. The substantial absolute scale of gas use in China and UK's power sector suggests significant potential for CCUS deployment on natural gas power plants.

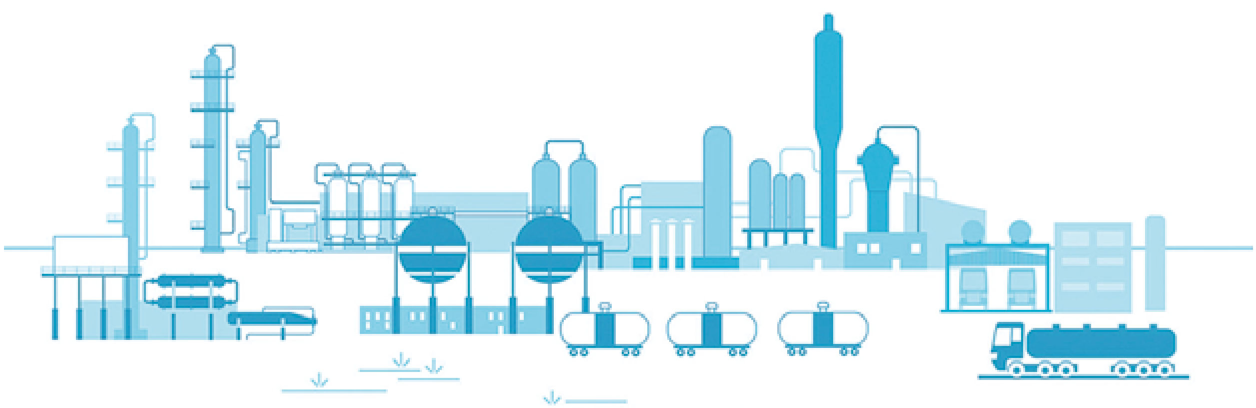
Two primary technological pathways lead to net-zero gas power:

1. Fuel decarbonisation	(e.g., hydrogen blending, progressing toward 100% H2 combustion; or the use of biomethane from anaerobic digestion; for biomethane, the associated CO_2 from the digester should be permanently stored or beneficially used)
2. Flue gas decarbonisation	(applying CCUS to existing or new NGCC plants).

While hydrogen represents a potential long-term zero-carbon solution, its widespread adoption faces significant hurdles, including technical challenges for high-level blending or pure hydrogen combustion in existing turbine designs, alongside the need for major cost reductions and supply chain scaling. The combustion of renewable methane, while resource-constrained, presents a near-term, drop-in fuel solution. When coupled with CCUS, it can achieve net-zero or even net-negative emissions, offering a highly actionable demonstration of the fuel decarbonisation pathway. In contrast, **applying CCUS (flue gas decarbonisation) offers a broader, near-term pathway to achieve deep emissions reductions from the existing and new NGCC fleet**, providing a crucial and bankable bridge in the energy transition.

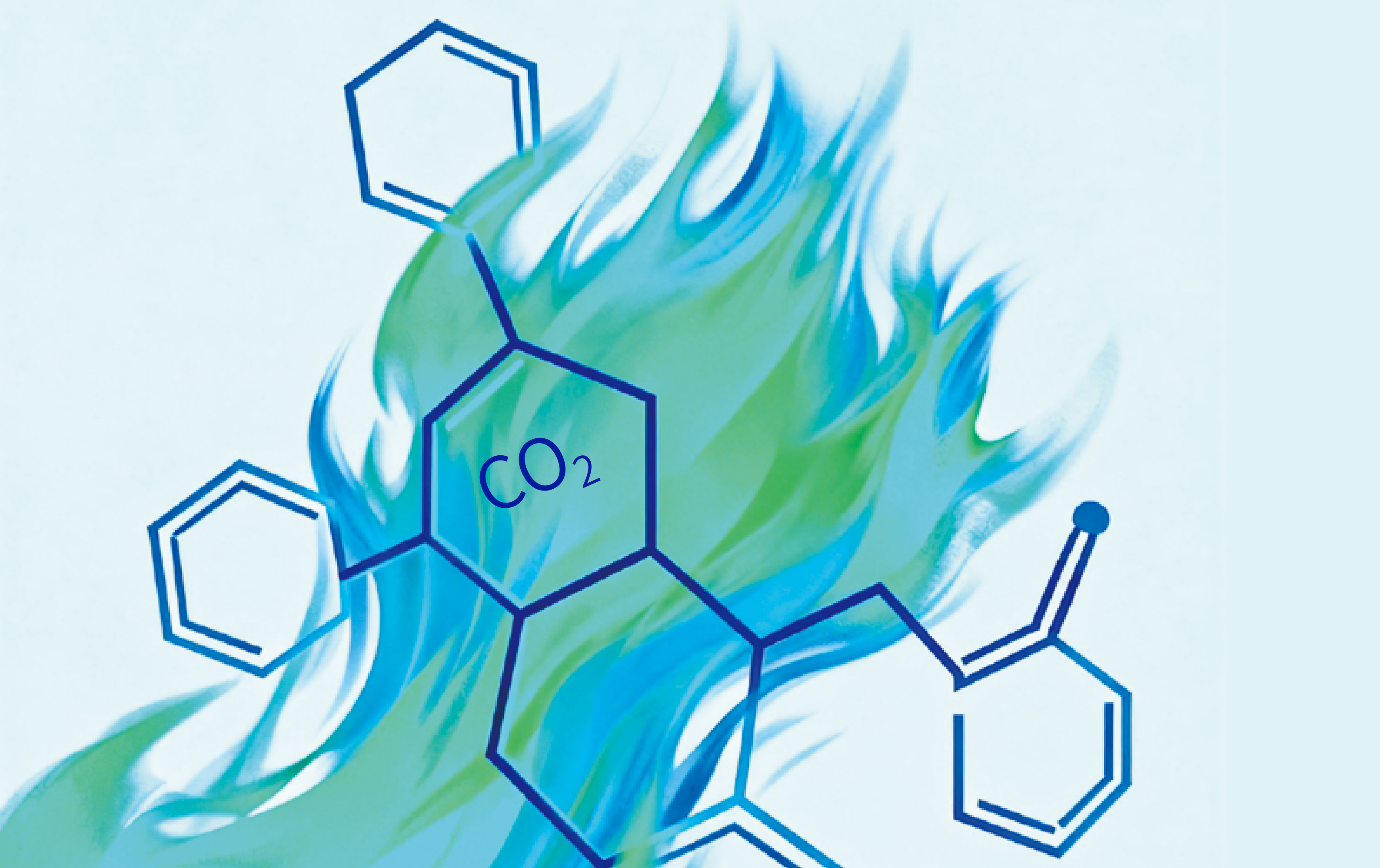
Applying CCUS to NGCC plants, however, presents distinct engineering challenges compared to coal-fired applications. NGCC flue gas is characterised by a **low CO_2 concentration (~3-5% without supplementary duct firing), giving a high volumetric flow for the amount of CO_2 captured, and high oxygen content (13-18%).** These features place higher demands on capture technologies regarding separation efficiency, energy penalty minimization, and solvent degradation resistance, representing key focal points for current research and development.

This report provides a comprehensive analysis of carbon capture technology for NGCC plants, systematically reviewing its current status, core technical and economic challenges, and future development pathways. It posits that deploying CCUS on NGCC is more than a mitigation measure; it constitutes a system-level solution integral to ensuring energy security, building a modern, resilient power system, and ultimately achieving carbon neutrality for the entire energy system.



2

Why Amine Post-combustion Capture is the Only Viable Option for Large-scale NGCC Decarbonisation



At present, amine-based post combustion capture remains the only credible technology for large-scale, point-source commercial CO_2 capture from NGCC power plants. This conclusion is reinforced by the current status of alternative approaches, none of which are yet ready or suitable for deployment at scale on typical NGCC units.

The immaturity or inapplicability of alternative technologies is illustrated by the following examples:

Allam Cycle:	Despite being under development for over a decade9F9F, the Allam Cycle is not yet ready for commercial service. Even its proprietors acknowledge this limitation; recent business updates indicate a strategic shift towards offering amine-based post-combustion capture using a proprietary solvent (Entropy Inc.) as a near-term solution (see Box 1).
Solid Adsorbents (Svante):	Svante's metal-organic framework (MOF) solid adsorbent technology, though under development for nearly two decades, is stated by the company to be non-competitive for flue gases with CO_2 concentrations below 12%. Since typical gas turbine flue gases contain only 3~5% CO_2, this technology is currently unsuitable for NGCC applications. Furthermore, even at higher concentrations, there may be fundamental thermodynamic limits on the minimum exit CO_2 levels achievable, which constrains the maximum capture rate. Consequently, Svante also offers amine-based post-combustion capture using BASF's OASE® blue solvent as their primary solution for gas power (see Box 2).
Potassium Carbonate (Capsol):	Capsol Technologies offers a process where flue gas is pressurised and moderately warmed to enable capture using potassium carbonate, with the CO_2-depleted gas subsequently expanded to recover mechanical work. However, this technology is currently only offered for retrofits to relatively small open-cycle gas turbines (OCGTs). The process utilizes turbine exhaust heat to warm the depleted flue gas and excludes a steam boiler; in effect, this adds an indirectly-heated gas turbine bottoming cycle rather than integrating with the steam cycle of a conventional combined-cycle gas turbine (CCGT; see Box 3).

Given these constraints, amine-based post-combustion capture is currently the only realistic, sufficiently mature, and adaptable option for rapid, large-scale decarbonisation of the existing and forthcoming NGCC fleet. The following chapter reviews the state of the art for amine-based NGCC+PCC systems, examining current design standards, solvent performance, and achievable capture rates.

Box 1: Net Power's statements on the status of the Allam Cycle

"Non-cash impairment of other intangible assets[10]:	During the quarter, the Company completed a market analysis of its oxy-combustion technology, identifying slower than anticipated acceptance and deployment relative to previous expectations. The value engineering efforts on Project Permian identified significant cost reductions and performance improvements, but not to a level that is economically competitive in the current market. These events resulted in an impairment of the carrying value of the technology and associated assets on the Company's balance sheet."
"Optimizing capital allocation to deliver clean firm power[11]:	The Company views its oxy-combustion technology as a viable, long-term solution for low-carbon intensity power generation. The Company will prudently invest capital to maintain its leadership position in oxy-combustion technology, including engineering efforts and testing at its demonstration facility, but may opportunistically invest a greater portion of its available capital in near-term power projects with Entropy."

"Net Power's recent press release announced a signed letter of intent with Entropy to deploy Entropy's post-combustion capture (PCC) technology for clean firm power projects in the United States. Additionally, Net Power shared its plans to deploy this solution on Net Power's existing sites, starting with its Project Permian location in West Texas, where it is targeting first clean power in 2028."[11]

"The addition of a post-combustion technology to Net Power's suite of solutions makes the company ready to deploy clean gas generation this decade, ahead of the competition."

Box 2: Svante MOF solid adsorbent capture status for gas power applications

“Svante’s Award-Winning Solid Sorbent-Based Filters for Carbon Capture”

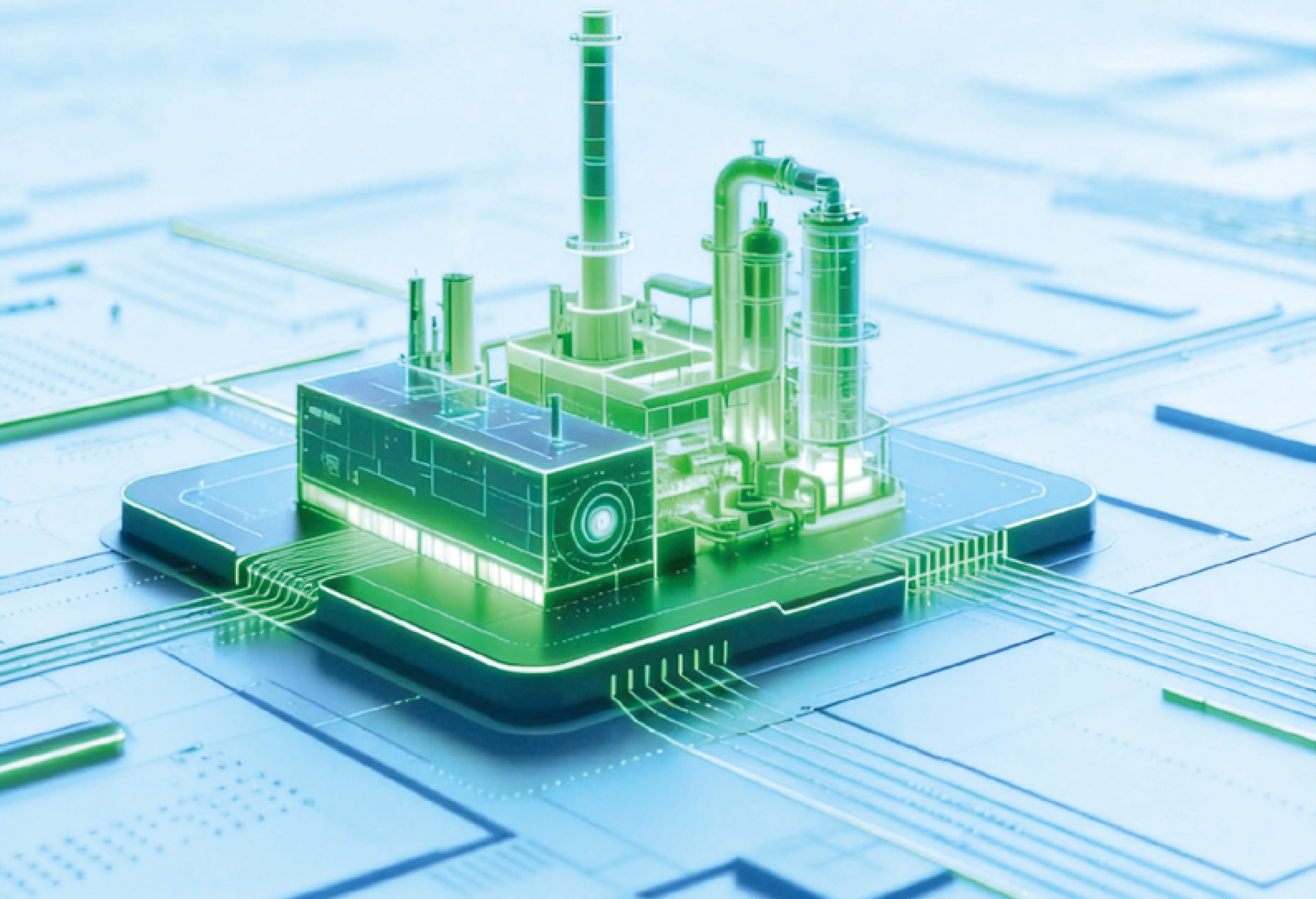
We’ve built our name in the industry for our world-class second-generation carbon capture technology: solid sorbent-based filters. This technology has an edge over other technologies such as liquid amines for a number of reasons, including being more environmentally responsible, efficient, and robust in the face of flue gas contaminants. Svante’s solid sorbent, CALF-20 is best suited for CO_2 concentrations 12% and higher.[12]

“OASE® blue offers Svante customers a commercially available carbon capture solution with high capture rates up to 99+%, low energy and amine consumption. OASE® blue is the paramount technology for use in flue gas liquid amine carbon capture from sources such as natural gas power plants.”[13]

Box 3: CapsolGT for open cycle GT

This technology is being applied to smaller installations based on open-cycle gas turbines (order tens of MW vs 100’s of MW for combined cycle gas turbine power plants). It captures CO_2 from a gas turbine’s hot exhaust. The approach requires all of the flue gas to be cooled and recompressed after it has been expanded to around atmospheric pressure in the gas turbine, so that the CO_2 capture by potassium carbonate will function with a high enough partial pressure of CO_2[14]. After capture, the depleted flue gas is heated and then expanded back to atmospheric pressure to drive the flue gas compressor and generate power[15].

3 Review of the State of the Art for Gas Power Plant CO_2 Capture



3.1 Current Status of NGCC Plants with Amine-Based Post-Combustion Capture

Public domain information on the latest state of the art for NGCC post-combustion carbon capture deployment arises mainly from U.S. Department of Energy (DOE)-funded Front-End Engineering Design (FEED) studies, as summarised in Table 1. In the UK, a FEED study and a subsequent detailed design exercise have been undertaken for the Net Zero Teesside project; however, no detailed public reports are available yet. Information is currently limited to accounts such as conference presentations, videos[15, 16, 17] and web articles[18, 19, 20]. Other important information has appeared in the public domain through NGCC post-combustion carbon capture permitting applications in the UK, which discuss specific plant design aspects and emissions to the atmosphere. Key details from these applications are also reflected in Table 1.

It is important to note, however, that none of these sources represent actual operating experience. A commercial plant design does not guarantee performance as predicted. Until multi-year operational data from commercial-scale NGCC post-combustion carbon capture plants become available, the current “state of the art” remains largely theoretical. Furthermore, many of the available sources are authored by parties with a commercial interest in the technologies described, which may introduce bias into their evaluations.

Table 1 synthesises recent FEED studies and public disclosures, revealing several key design features:

Capture Rates:	Rates of 90~95% are commonly targeted, although some studies (e.g., Bechtel-Panda) consider 85%.
Deployment Pathway:	Retrofitting existing NGCC units is the dominant deployment pathway in the USA. In the UK, while there are significant retrofit projects (e.g., VPI Immingham), current flagship deployment plans favour new builds (e.g., Net Zero Teesside, Connah’s Quay).
Operational Flexibility:	Flexibility is recognised as essential, with some designs (e.g., Mustang Station) specifying parallel capture trains to accommodate it.

Economic viability varies significantly depending on scale, load factor, and integration strategy. For example, the Polk Unit 2 CCGT with PCC targets costs at or below \$80/t CO_2, while the GE-Linde-Southern Company NGCC+CCS FEED Study estimates costs around \$100/t CO_2. Data from the Mustang Station carbon capture FEED study (Piperazine Advanced Stripper, PZAS™) further illustrate the impact of load factor: capture costs were approximately \$85/t CO_2 at an 85% load factor but rose to \$166/t at 52%[21]. Beyond the examples in Table 1, estimates from Stanford University for an NGCC retrofit show the levelized capture cost to be about \$123/t CO_2 at an 85% load factor, increasing sharply to roughly \$212/t at a 40% load factor—a range that better reflects the actual operating patterns of many gas-fired power plants[22]. **Compounding these technical sensitivities, macroeconomic conditions have significantly shifted the cost baseline**. An analysis of recent FEED studies indicates that from late 2020 to mid-2024, inflation combined with rising interest rates drove a 59% increase in the unit cost of carbon capture for NGCC power plants, with energy price volatility adding a further 10~15% to operational expenses[23]. Consequently, static cost estimates from earlier FEED studies may require upward adjustment to reflect current market realities.

The projects in Table 1 collectively represent the most advanced pre-commercial understanding of NGCC+PCC, but real-world validation remains pending.

Table 1 NGCC+PCC FEED studies and other recent published information on the state of the art (Data as of March 2026)

Name	Plant Configuration[a]	Capture scale	Design Capture Rate (%)	Status	Remarks
United States					
1. EPRI-Fluor Elk Hills NGCC Carbon Capture FEED Study[24]	Retrofit of existing 550 MWe NGCC + New Boiler for steam	~1.46 $MtCO_2$/yr	N/A (Fixed Mass Capture)	FEED Completed (Project End: Feb, 2022)	Uses Fluor Econamine FG Plus® solvent; Est. Cost $748M; Located in Tupman, CA
2. Bechtel-Panda Sherman NGCC Carbon Capture FEED Study[25]	Retrofit of existing 758 MWe NGCC (2x2x1 duct-fired facility with F class turbines)	~0.645 $MtCO_2$/yr	85%	FEED completed (Mar 2022)	Uses 35 wt% MEA solvent; ~$114.50/t$CO_2$ capture cost; Located in Sherman, Texas
3.Piperazine Advanced Stripper (PZAS™) FEED Study[26]	Retrofit of existing 464 MWe NGCC (Mustang Station)	~0.85 $MtCO_2$/yr	90%	FEED completed (Mar 2022)	Two parallel capture trains preferred for operational flexibility.
4. Linde-BASF PCC at Southern Company Mississippi Power Plant[27]	Retrofit of 525 MWe NGCC (2×7FA GT + HRSG)	~1.63 $MtCO_2$/yr	90%	FEED completed (Sep 2022)	Uses OASE® blue solvent; 725M capex estimate.
5. GE-Linde-Southern Company NGCC+CCS FEED Study[28]	Retrofit of existing 2×1 7FA.04 NGCC (Barry Plant, AL)	~1.63 $MtCO_2$/yr	95%	FEED completed (Jun 2024)	Capture cost ~$100/t CO_2 (2023 USD, excl. transport & storage)
6. Polk Unit 2 CCGT with PCC (FEED Study)[29]	Retrofit of 1,190 MW (1,168 MW net) 4×4×1 CCGT	~3 $MtCO_2$/yr	95%	FEED completed (Dec 2024)	Uses ION Clean Energy ICE-31 solvent; cost target ≤ $80/t CO_2
United Kingdom					
1. VPI Immingham CHP Plant CCS Project[30]	Retrofit of existing GTs & Auxiliary Boilers with two parallel PCC plants	Up to 3.3 $MtCO_2$/yr	95%	FEED Completed (2023); Awaiting FID	Uses Shell Cansolv DC-103 solvent; CO_2 compressed for pipeline storage.
2. Net Zero Teesside (NZT)[31]	New-build 742 MWe NGCC with CCS (GE Vernova 9HA.02)	Up to 2 $MtCO_2$/ yr	95%	FEED Completed (Q2 2024); FID Reached (Sep 2024)	1. New-build facility. 2. Uses Shell CANSOLV® solvent. 3. Commercial operation planned for 2027.
3. Connah's Quay Low Carbon Power Project	New-build NGCC with carbon capture (Two phases, up to 690 MW each)	up to 1.2 $MtCO_2$/yr for 550MW single unit	N/A	FEED Commenced (Dec 2024)	Connected to HyNet CO_2 infrastructure; Uses Technip Energies Canopy™ (Shell CANSOLV®).
Other Regions					
1. Genesee Carbon Capture Facility FEED Study[32]	Retrofit of NGCC plant (MHI KM CDR™ process)	~ 3 $MtCO_2$/ yr	95%	FEED completed (Oct 2023)	Located in Warburg, Alberta, Canada; Uses KS-21™ solvent.

a. Indicates capacity (MWe), and whether the plant is a retrofit or new-build.

3.2 Differences between Solvents for NGCC+PCC Applications

Various proprietary and non-proprietary amine solvents are currently proposed or commercially available for NGCC+PCC applications. These are currently often being described as separate 'technologies' but in fact the underlying technology appears to be very similar in all cases, with relatively minor differences in the arrangements that are stated to improve the efficiency or environmental performance.

Limited public disclosure hinders objective comparisons between solvents. However, one such exercise was undertaken in 2016 for the World Bank by independent consultants[33]. Based on information provided by solvent suppliers at the time, normalized to a common balance-of-plant design and cost assessment methodology, the analysis concluded that there was negligible difference in overall costs among the commercial amines examined. Furthermore, the analysis indicated no substantial advantage over a standard 30% w/w Monoethanolamine (MEA) baseline. This finding implies performance comparable to the 35% w/w MEA referenced in recent NGCC FEED studies[26].

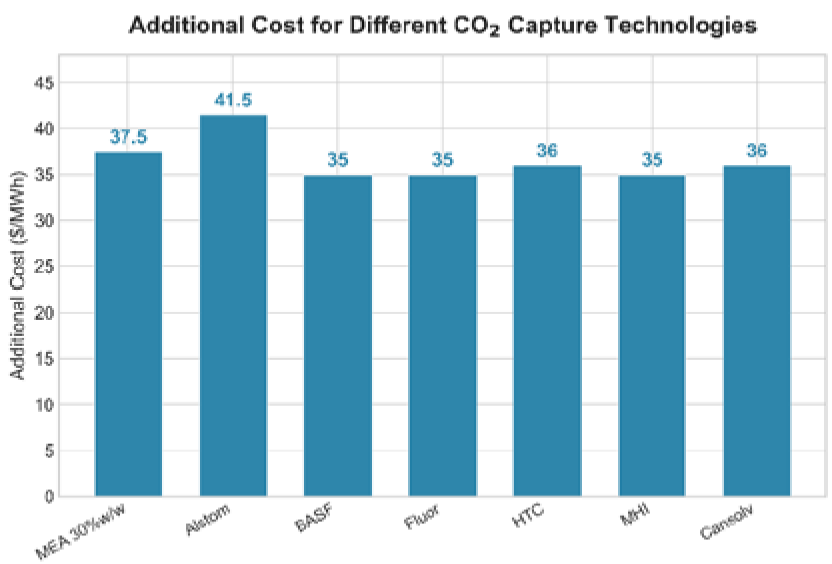


Fig. 2 Estimated variation in additional electricity cost for retrofitting a natural gas combined cycle power plant using MEA and various proprietary solvents[32]

It must again be emphasised, though, that there is no operational evidence confirming that the performance implied by the estimated costs in Fig. 2 will actually be realised in practice. Significant deviations from predicted solvent performance and associated costs are evident in Fig. 3, which reports data from two early large-scale operational projects, Boundary Dam and Petra Nova[34]. At these facilities, solvent management costs were reported to be 2~4 times higher than pre-deployment predictions, at least for periods of several years in the case of Boundary Dam[35].

For Boundary Dam, which captures less than 1 $MtCO_2$/yr, annual costs for solvent replacement alone were stated by the SaskPower chairman as $17.3M in 2015, $14.6M in 2016[35], and reported to a government committee as $13.6M in 2017[36], against initially-predicted costs of $5M. These solvent replacement costs are consistent with the elevated levels of variable operation and maintenance (O&M) costs shown in Fig. 3.

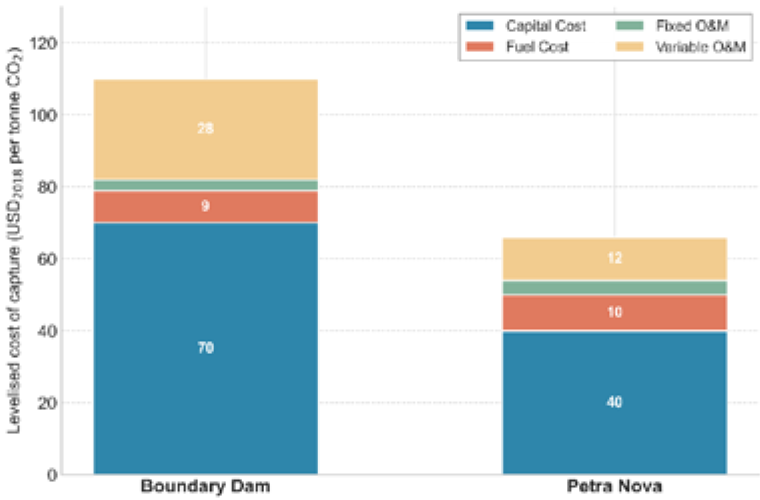


Fig. 3 Reported capture costs for Boundary Dam Unit 3 and Petra Nova[33]. This bar chart compares the levelised cost of capture (USD$2018 per tonne of CO_2) for the two carbon capture projects. Stacked bars illustrate cost components: capital cost (blue), fuel cost (red), fixed O&M (green), and variable O&M (purple). Variable O&M costs are predominantly attributed to solvent management and replacement. Cost data have a stated accuracy range of -10% to +15%. Proprietary solvents used: Boundary Dam 3 employed Cansolv DC-103[37], while Petra Nova used MHI KS-1[38].

3.3 Maximum Achievable Capture Rates

In the past, capture rates specified in standardised assessment studies of NGCC+PCC have been as low as 85% of the CO_2 in the flue gas stream[39].This lower target was often justified by the typically low CO_2 content in gas turbine flue gas (order 3~5% CO_2 v/v). However, IPCC scenarios that avoid dangerous climate change (see Fig. 4) require net global emissions to be net-negative for extended periods. This implies that any residual emissions to the atmosphere from fossil fuel use must be recaptured using carbon dioxide removal (CDR) techniques with equally permanent CO_2 storage, such as Biomass Energy with CCS (BECCS) or Direct Air Capture with CO_2 Storage (DACCS). PCC technologies deployed today will likely still be operating in 2050 and must serve as exemplars for further deployment. Therefore, the highest reasonable capture rates should be deployed. Evidence now suggests this is at or close to 100% of added CO_2 (i.e., CO_2 derived from fuel combustion), meaning the flue gases leave with around the same amount of CO_2 as was present in the atmospheric air used for combustion. For gas turbine flue gases, this corresponds to around 99% of the total CO_2 in the flue gas stream.

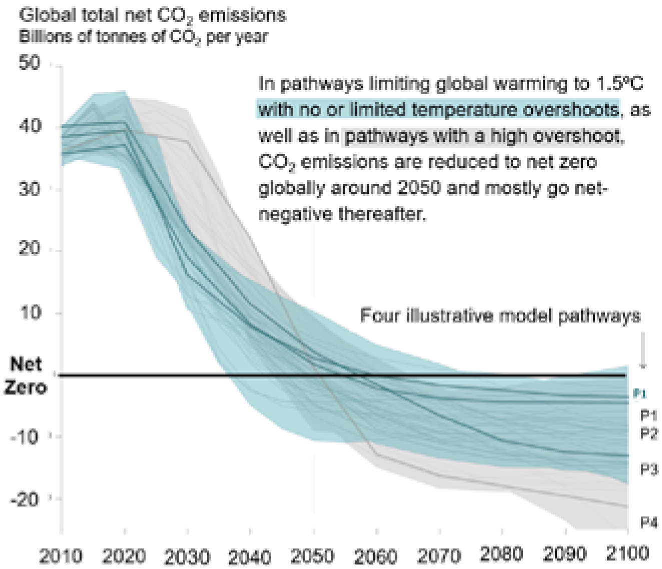


Fig. 4 Global CO_2 emission pathways from the IPCC special report ‘Global Warming of 1.5°C[40]. Virtually all 1.5°C pathways involve net-negative global emissions after 2050, as well as a rapid fall in global emissions.

Public-domain evidence for near-100% added CO_2 capture on gas turbine flue gases arises principally from the tests at the Technology Centre Mongstad (TCM) on MEA and CESAR1 (a non-proprietary piperazine/AMP blend thought to have some similarities to some proprietary solvents), as shown in Table 2.

Table 2 Tests on TCM CHP flue gas [41,42,43,44,45]

TCM run series	%w/w MEA	Capture rate	Packing height (m)	SRD (GJ/tCO_2)
MEA				
MEA-3	43%	86%	18	3.6
F2	36%	90%	18	3.8
B3-rep	37%	91%	18	3.6
D3-rep	36%	97%	24	3.7
CESAR-1				
K		85%	18	3.5
C		90%	18	3.4
D		98%	18	3.9
K		85%	24	3.3
AA		90%	24	3.5
BB		98%	24	3.75
Hume (2021)		~96%	24	~3.45*

*Minimum Specific Reboiler Duty.

The fundamental principles for achieving high capture rates in PCC capture are described by Michailos and Gibbins[46]. The desorber is operated to produce solvent with the lowest possible lean loading that does not incur excessive energy consumption (the inflection point), and the flow of lean solvent to the absorber is carefully controlled to give the maximum possible rich loading at the required capture rate. This theoretical analysis confirms the need for approximately 24 m of packing to achieve the highest capture rates, as demonstrated by the actual testing in Table 2. In 2024, a test campaign at the Guangdong Carbon Capture Test Platform, confirmed the viability of using desorber temperatures to ensure controlled operation at the inflection point, achieving associated high capture rates without excessive energy consumption[47]. This work was recently extended (December 2025) with 75 hours of continuous operation demonstrated at around 100% added CO_2 capture on coal flue gas. Further work at the Guangdong Carbon Capture Test Platform is envisaged, using air dilution to give CO_2 levels typical of those found in NGCC applications. The expectation is to achieve close to 100% added CO_2 capture (i.e. exit CO_2 levels equivalent to the CO_2 present in the air entering an NGCC power plant, in the region of 470 ppmv in the flue gas).

Clearly, though, while 100% added CO_2 capture is feasible, there is almost no scope to overperform at times to compensate for impaired performance over other periods, as would be the case for a lower target capture rate (e.g. 95%). This means that the maximum possible capture rate must be pursued at all times, including start-up and shutdown, as discussed in Section 3.4. It also means that the availability of the capture plant must be very high, or the power plant operation must be suspended if the capture plant (or CO_2 transport and storage system) is unavailable for use. Regulations also have to strike a balance between encouraging the best available technical approach of achieving these very high capture rates and recognising that, in practice, because there is no scope to overperform, 100% added CO_2 capture at source cannot be an absolute requirement. In this case, as already discussed, carbon dioxide removal technologies, such as BECCS and DACCS, would need to be used to recapture any uncaptured CO_2 to deliver net zero. Biomethane from anaerobic digestion, used in NGCC+PCC plants, would be one such BECCS option.

3.4 Flexibly-Operated Capture Using Solvent Storage: A Summary of the FOCUSS Project

The UK's Department for Energy Security and Net Zero funded the FOCUSS project (Flexible Operation of Capture Using Solvent Storage) under its Net Zero Innovation Portfolio[48]. This initiative specifically addresses a critical operational gap: maintaining high CO_2 capture rates during plant start-up, shutdown, and part-load operation—key challenges for flexibly operated NGCC plants.

This section summarises a recently completed project investigating the use of solvent storage to maintain full CO_2 capture rates during NGCC start-up and shutdown (SUSD). The information is based on the most recent public domain material prepared for the IEAGHG PCCC8 conference[49]. All project reports will be released as Key Knowledge Deliverables (KKDs) on the DESNZ website in due course.

The FOCUSS project was delivered by a consortium consisting of SSE Thermal (project lead), the University of Sheffield and AECOM. It aimed to accelerate the time to market for technology that enables amine post-combustion capture plants to achieve 95~99% CO_2 capture levels at all times, including during start-up, shut-down, and other transients. The project progressed rapidly from conceptual engineering predictions to de-risked technology, delivering new solutions to support UK targets of 15~30 GW of gas power with near net-zero CO_2 emissions by 2050.

Modifying the amine CO_2 capture process to utilise solvent storage involves separating the absorption and stripping processes via two inline solvent holding tanks (Fig. 5). This enables the independent production of lean and rich solvent. In this way, the desorber can always be operated under conditions that produce the optimum lean solvent loading—or not be operated at all—while the absorber can always be supplied with the precise amount of lean solvent required to achieve design CO_2 capture rates. This simultaneously maximises rich loading in order to minimise regeneration energy requirements. In particular, this approach allows high CO_2 capture rates during start-up events for NGCC plants, with the absorber drawing lean solvent from storage while the solvent regeneration system reaches operational pressure and temperature. Typically, a dispatchable NGCC plant with CCS in a renewables-heavy system might experience of the order of 200 warm starts and 50 cold starts per year; maintaining capture rates during these events is therefore essential to achieve high overall annual capture rates.

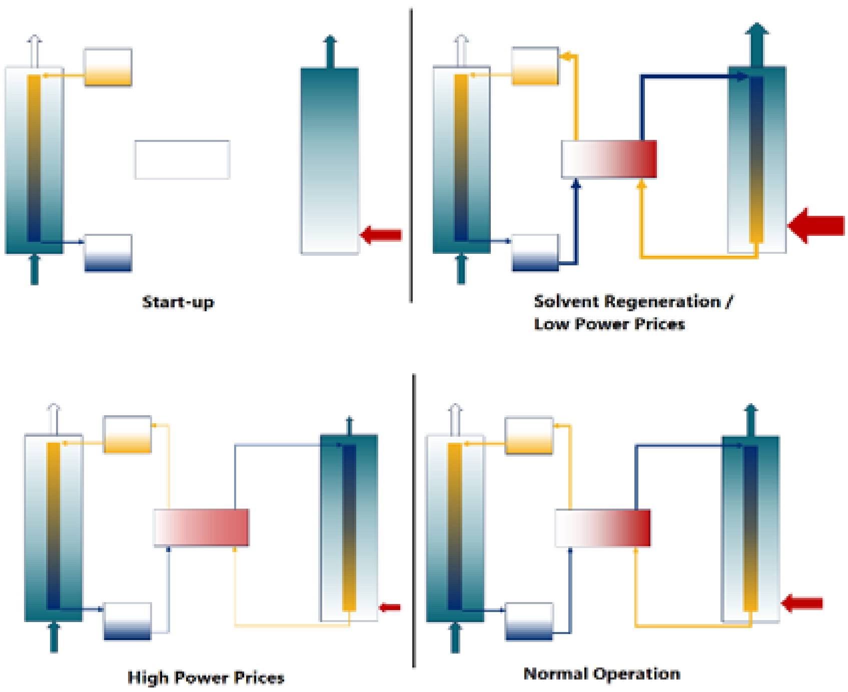


Fig. 5 Solvent storage operational modes

FOCUSS demonstrated that the design CO_2 capture rate can be achieved throughout all operational modes, including start-up, shut-down, and transient periods, provided there is sufficient stored lean solvent and that solvent inventory is appropriately managed. Incorporating solvent storage also provides additional benefits, such as the ability to respond promptly to changes in NGCC flue gas flow rate or composition by monitoring the absorber performance envelope and supplying adequate lean solvent to match flue gas changes without the delay inherent in the stripping process. Solvent storage is also anticipated to enhance the flexibility and grid stabilisation potential of NGCC plants by allowing rapid modulation of the low-pressure (LP) steam flow to the reboiler—and hence a very rapid increase or decrease in electricity output—without affecting the CO_2 capture rate.

The FOCUSS project used extensive testing on the 1 tonne per day (tpd) amine CO_2 capture plant at the Translational Energy Research Centre (TERC) at Sheffield to demonstrate the use of solvent storage. Capture rates of 95 - 99+% of incoming CO_2 were achieved during all plant operational modes (Fig. 6). Tests have also been conducted at the larger Guangdong Carbon Capture Test Platform (40 tpd), showing rapid start-up using an industry-standard once-through thermosyphon reboiler configuration combined with desorber inventory circulation.

In addition to the test campaigns, this work utilised real-world data from an operational NGCC plant to highlight and quantify the potential for enhanced CO_2 abatement during start-up using previously wasted 'early steam' (Fig. 7). This is steam generated during the NGCC start-up sequence that is normally rejected to the condenser due to low steam quality. Its use in the reboiler can lead to a step change in the cost of CO_2 abatement during start-up and an increase in the net thermal efficiency of the sequence. This is achieved by both avoiding any electricity output penalty associated with solvent storage and significantly reducing the solvent inventory required.

Practical approaches were also developed to achieve pipeline-quality CO_2 purity as soon as possible and to accommodate heating-rate restrictions on the large heat exchangers used for crossflow lean–rich heating and reboilers.

Costs for implementing solvent storage were estimated in a previous study to be a relatively modest £11 million (2018 prices) for an 850MW NGCC plant[50]. However, this will depend on the specific solvent cost for the additional inventory. The solvent used must also be capable of withstanding the initial stages of gas turbine operation, when there may be elevated levels of NOx.

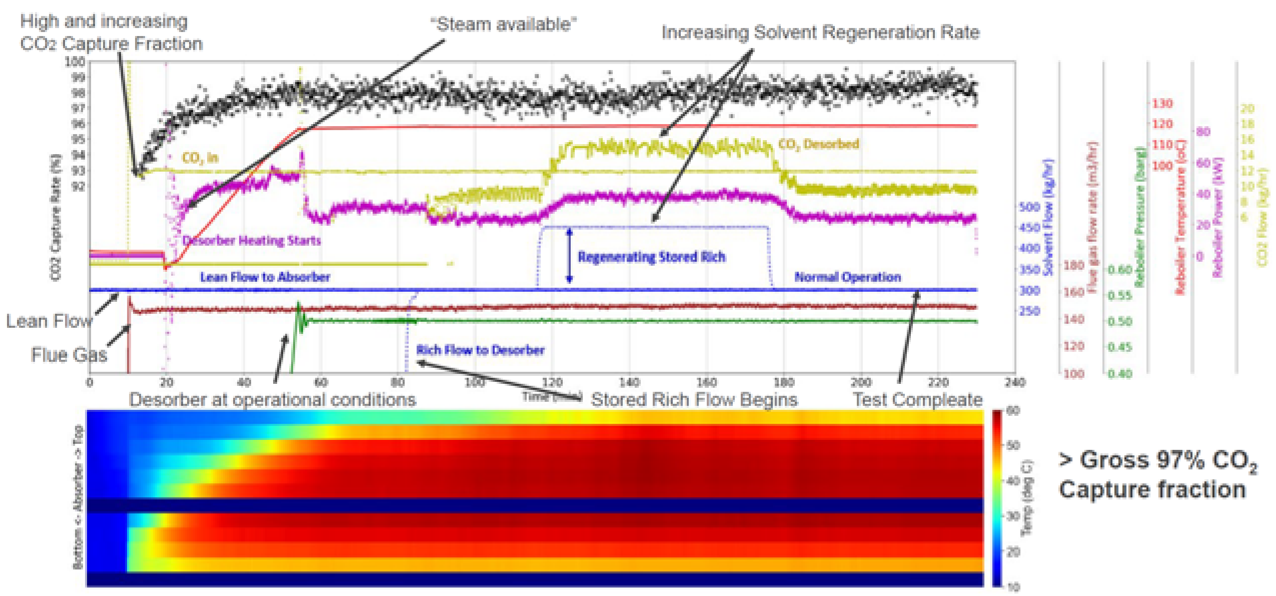


Fig. 6 A start-up sequence using lean and rich solvent storage shows high capture from the outset, rising as the absorber temperatures increase, and also subsequent regeneration of the stored rich solvent in parallel with normal plant operation (mimicking the availability of excess 'early steam').

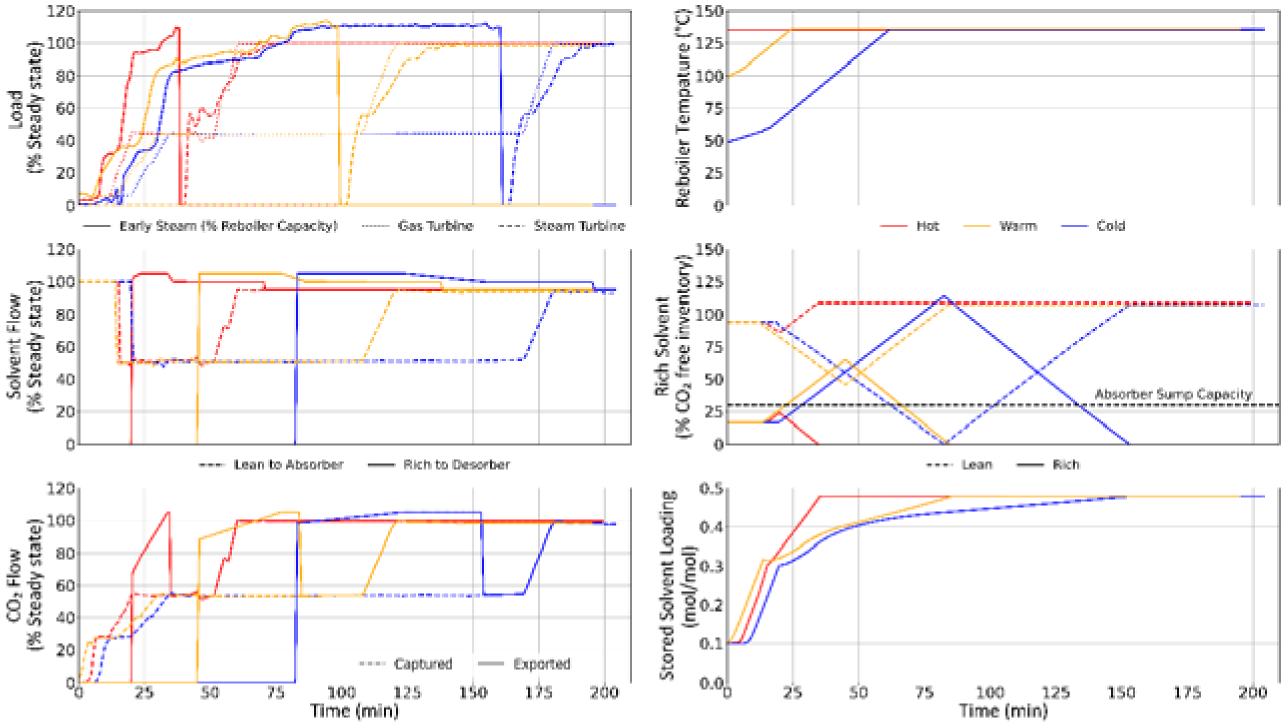


Fig. 7 An NGCC start-up sequence produces steam that cannot be admitted into the steam turbines; this is normally by-passed and dumped into the condenser. However, using this “early steam” and “late steam” in the reboiler allows solvent to be regenerated at an early stage during start-up, minimising the amount of solvent storage required.

4

Case Study of Representative Chinese NGCC Plant: the Yangpu Carbon Capture Pilot Unit

4.1 Plant Overview and Operational Context

In China, natural gas-fired power primarily serves as a peak-shaving power source for regions with high electricity demand. Due to substantial energy demand, stringent environmental protection requirements, and supportive policies, eastern China has become the primary region for gas power development. From a regional distribution perspective, China's NGCC plants exhibit a spatial imbalance pattern characterised as "east-heavy, west-light, and concentrated", primarily located in economically developed areas such as the Yangtze River Delta, the Pearl River Delta, the Beijing-Tianjin-Hebei region, and the Sichuan-Chongqing region.

To illustrate the technical and operational considerations for deploying carbon capture on NGCC plants in China, this chapter presents a case study based on the Huaneng Yangpu Thermal-Gas Cogeneration Power Plant in Hainan Province. This facility exemplifies several key characteristics relevant to NGCC+CCS deployment, including its role in grid peak-shaving, flexible operation requirements, and the integration of a carbon capture testing platform.

The Huaneng Yangpu Thermal-Gas Cogeneration Power Plant is located in Hainan Province, featuring 2×495 MW 9F gas-steam combined cycle cogeneration units. The plant supplied 124,800 tonnes of heat in 2025, with a temperature of 308°C and a pressure of 10.9 bar. It is designated for peak-shaving and flexible operation to support Hainan's renewable energy integration. A summary of key plant parameters is provided in Table 3. The general layout of the plant, indicating the location of the CO_2 capture testing platform, is illustrated in Fig. 8.

Table 3 Key parameters of the Huaneng Yangpu NGCC Plant

PARAMETER	VALUE
Unit configuration	2×495 MW, 9F gas-steam combined cycle
Commissioned	2022
Heat supply (2025)	124,800 tonnes (308°C, 10.9 bar)
GHG emissions (2023)	882,762 tCO_2
Unit 1 annual operating hours (2025)	~1,300 h (high-load: 18%)
Unit 2 annual operating hours (2025)	~2,400 h (high-load: 6.5%)

Fig. 8 General layout of Huaneng Yangpu NGCC plant, showing the location of the CO_2 capture platform (red highlighted area). The platform was designed in conjunction with the power plant.

Due to daily and seasonal temperature variations, combined with abundant intermittent renewable energy resources in Hainan, electricity demand in the province exhibits significant peak-valley differences. Gas-fired units can rapidly respond to grid load changes and perform timely peak-shaving duties, typically demonstrating extended operation during summer months and reduced operation during winter. Typical peak-regulation characteristics for Unit 2 during the off-peak season (winter) are shown in Fig. 9. The Huaneng Yangpu Plant is required to operate in peak-shaving mode to ensure grid security and meet the power system's demand for flexibility and stability.

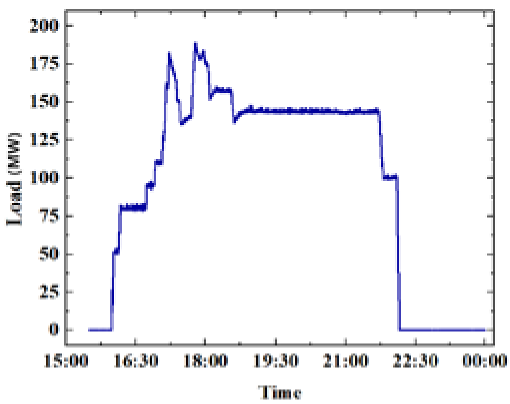


Fig. 9 A Typical Peak-regulation characteristics for Unit 2 in off-peak season (winter)

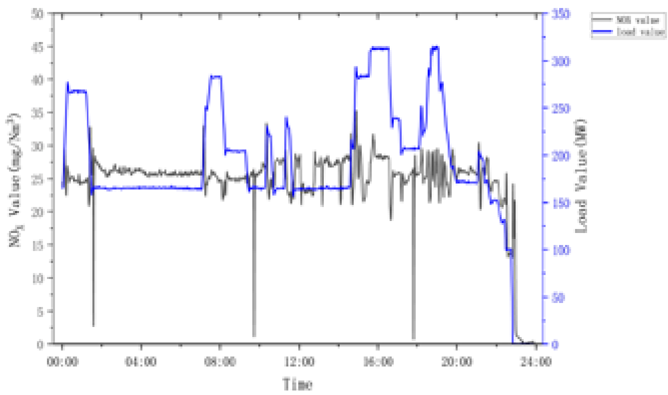


Fig. 10 A Typical peak-regulation characteristics for Unit 2 during summer, showing load and outlet NOx (after DeNOx system) variations in real time

During the summer peak electricity demand period, NGCC units must rapidly respond to grid dispatch instructions. The summer peak-regulation characteristics, including the correlation between unit load and NOx emissions, are shown in Fig. 10. The units typically maintain high-load operation for extended periods from afternoon to evening to meet baseload power supply demands. NOx emission concentrations show a strong positive correlation with load variations; when load increases, the combustion chamber temperature rises, intensifying thermal NOx formation and resulting in increased emissions. However, during stable high-load phases, combustion optimisation and efficient DeNOx system operation enable NOx emissions to stabilise or even exhibit controlled reductions within compliance limits. Furthermore, elevated summer air temperatures may cause gas turbine operating conditions to deviate from design parameters, triggering transient fluctuations in NOx emissions. Overall, the load and NOx curves exhibit dynamic characteristics of synchronised increases and coordinated suppression.

Based on 2025 operational statistics, Unit 1 of the Yangpu Thermal Power Plant recorded a cumulative annual operating time of approximately 1,300 hours, of which high-load operation (>80% of rated load) accounted for only 18% of the operating period. Unit 2 recorded a cumulative annual operating time of approximately 2,400 hours, with high-load operation accounting for 6.5% and low-load operation accounting for 93.5% of the operating period. The plant determines the daily start-up and shutdown schedule for each unit based on grid dispatch instructions.

4.2 Carbon Capture Testing Platform Design

The carbon capture testing platform, illustrated in Fig. 11, represents China's first natural gas-fired post-combustion CO_2 capture testing platform at an approximately 2,000 t/yr scale. It is being developed to serve as an international testing platform for natural gas-fired CO_2 capture.

Fig. 11 Huaneng Yangpu NGCC Carbon Capture International Testing Platform

The capture project involves a retrofit to Units 1 and 2 of the plant, utilising chemical absorption technology independently developed by CERI. The facility has an overall height of 28 meters and a floor area of 300 m². The CO_2 capture testing platform commenced operation on 30 June 2023, achieving coordinated control and operation between the carbon capture unit and the peak-shaving power plant. A summary of key platform parameters is provided in Table 4.

Table 4 Key parameters of the Yangpu CO_2 capture testing platform

PARAMETER	VALUE
Scale	~2,000 t/a
Design flue gas flow rate	3,500 m^3/h
Design CO_2 content	~4%
Design capture rate	90%
Actual capture rate	Up to 99%
Absorber dimensions	Diameter 0.48 m; packing height 15.2 m
Regenerator dimensions	Diameter 0.22 m; packing height 12.2 m
Packing type	Raschig RSP 250 (316 stainless steel)
Flue gas composition	3.5~4.5% CO_2, 12~17% O_2, < 50 mg/Nm^3 NOx

The CO_2 capture system takes slipstream flue gas and utilities, including steam, electricity, and process water, from Units 1 and 2. In most operating conditions, only one unit is in service, and the choice of unit is determined by grid dispatch requirements. The pilot-scale CO_2 capture unit is connected to the flue gas ducts of both units; by switching valves, flue gas can be drawn from either unit as needed. Given the high temperature and pressure of the steam supply for solvent regeneration, depressurising and desuperheating are performed to meet the required conditions for the reboiler inlet. The conditioned steam then flows into the reboiler, which is connected to the bottom of the regeneration column and serves as a heat exchanger to transfer heat to the rich solvent. An overview of the process configuration, illustrating the integration of the CO_2 capture system with the NGCC plant, is presented in Fig. 12.

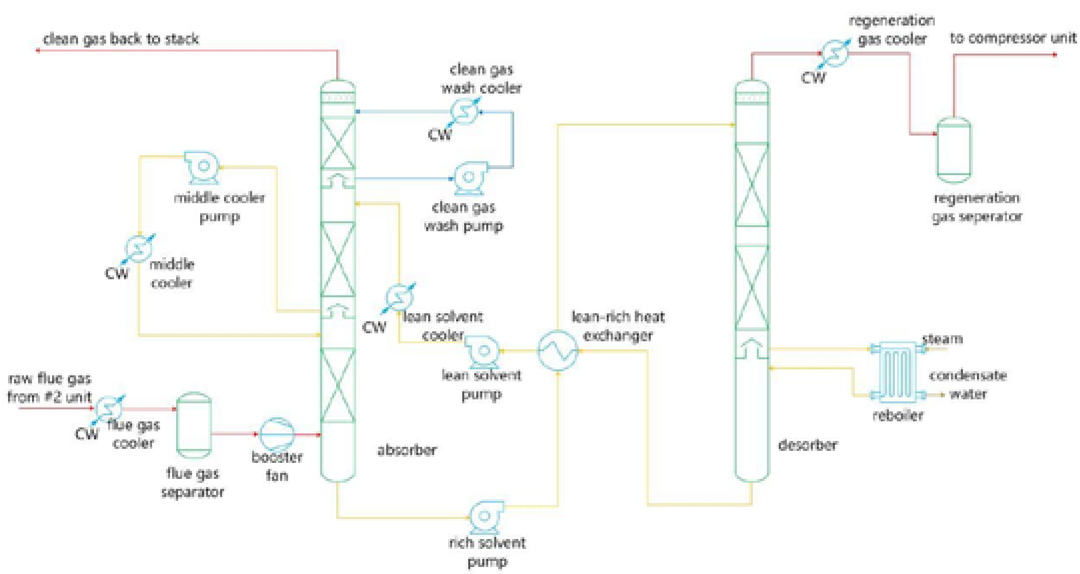


Fig. 12 Overview of Process Configuration (showing single-train operation)

Raw flue gas is pressurised by a booster fan and is then fed into one or both of the two parallel absorbers. Inside each absorber, CO_2 is removed as the gas flows countercurrent to the lean solution. The cleaned flue gas from both absorbers is combined and discharged. The rich solvent from the bottom of each absorber is pumped to the rich–lean heat exchanger. After being heated, the solvent is split again into two parallel regenerators. The high-concentration CO_2 streams from the top of the two regenerators are combined into a single outlet. The lean solvent from the bottom of both regenerators is collected in a common reboiler for thermal regeneration. After cooling through the heat exchanger, the regenerated lean solvent is split once more and returned to the two absorbers, completing the closed-loop solvent cycle.

The platform employs a dual-train parallel configuration, which offers several operational advantages:

Steady-state operation:	The load is evenly distributed between the two trains, allowing each absorber to achieve near-design capture efficiency.
Single-train operation:	By closing the flue gas and solvent valves of one train, the entire load can be directed to the other, enabling seamless transition between maintenance and online operation.
Future expansion:	The parallel design accommodates increased flue gas flow rates for capacity expansion.
Cost efficiency:	The shared use of key equipment with adequate turndown capability (reboiler and heat exchanger) controls capital investment and operating energy consumption.

Since the Yangpu test platform is a pilot-scale facility, the operation of the CO_2 capture system takes into account the associated testing costs. Therefore, in practice, when the plant is being used for solvent performance assessments rather than operability tests, one absorber-regenerator train is typically put into service. This approach effectively controls operating expenses while still allowing key solvent performance parameters to be evaluated.

The tower packing internals consist of Raschig ‘Super Pak’ RSP 250 structured packing. This has a high specific surface area, 250 m2/m3, and an open corrugated geometry, which promotes efficient gas-liquid contact while maintaining a low pressure drop. Manufactured from 316 stainless steel, the RSP 250 is suitable for CO_2 capture from high O2 content natural-gas fired flue gas, where oxidative degradation is a concern.

4.3 Research Capabilities and Future Outlook

As a key collaborative partner within the International Test Center Network for CCUS (ITCN), CERI's Yangpu test facility enables research across multiple domains, including absorbents, process engineering, solvent management, and dynamic operations. It provides a testing environment for carbon capture researchers, both domestically and internationally, and serves to attract cutting-edge overseas technologies for cross-testing validation. The Global CCS Institute report "CCS State-of-the-Art Technologies 2025" describes the Yangpu testing platform as "It is developed to the first international testing platform for solely natural gas-fired CO_2 capture globally... The platform verified Huaneng's HNC-7 hybrid carbon capture solvents and process intensification technologies, as well as the flexible operation strategies. It has established coordinated control and operation between carbon capture unit and peak shaving power plants.

By adjusting operating conditions and parameters, the platform can achieve a CO_2 capture rate of up to 99%, while the dry-basis concentration of CO_2 desorbed from the regeneration tower can exceed 98%. These results demonstrate the feasibility of achieving near-complete CO_2 removal from low-concentration NGCC flue gas under flexible operating conditions. The detailed equipment layout of the testing platform is shown in Fig. 13.

Fig. 13 Testing Platform Equipment Layout

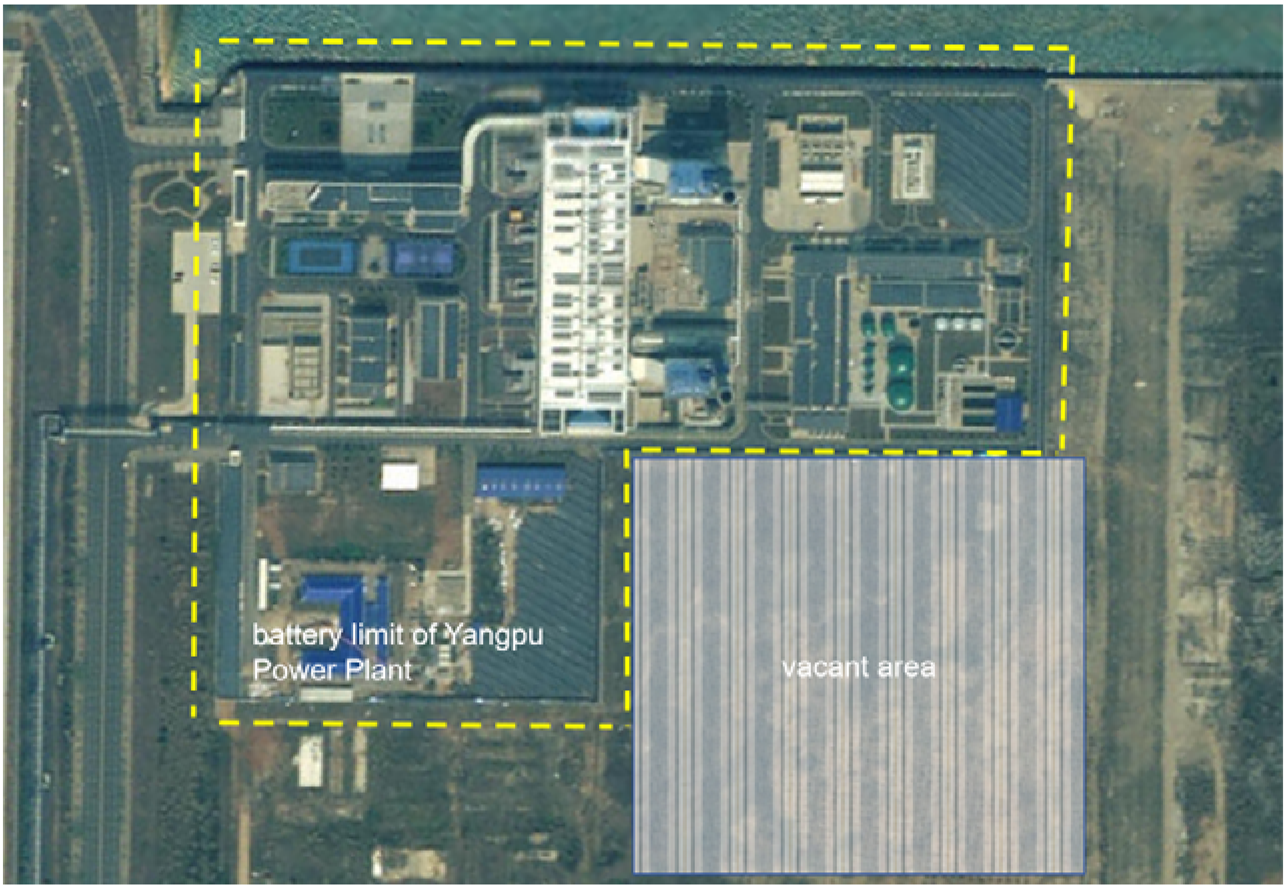
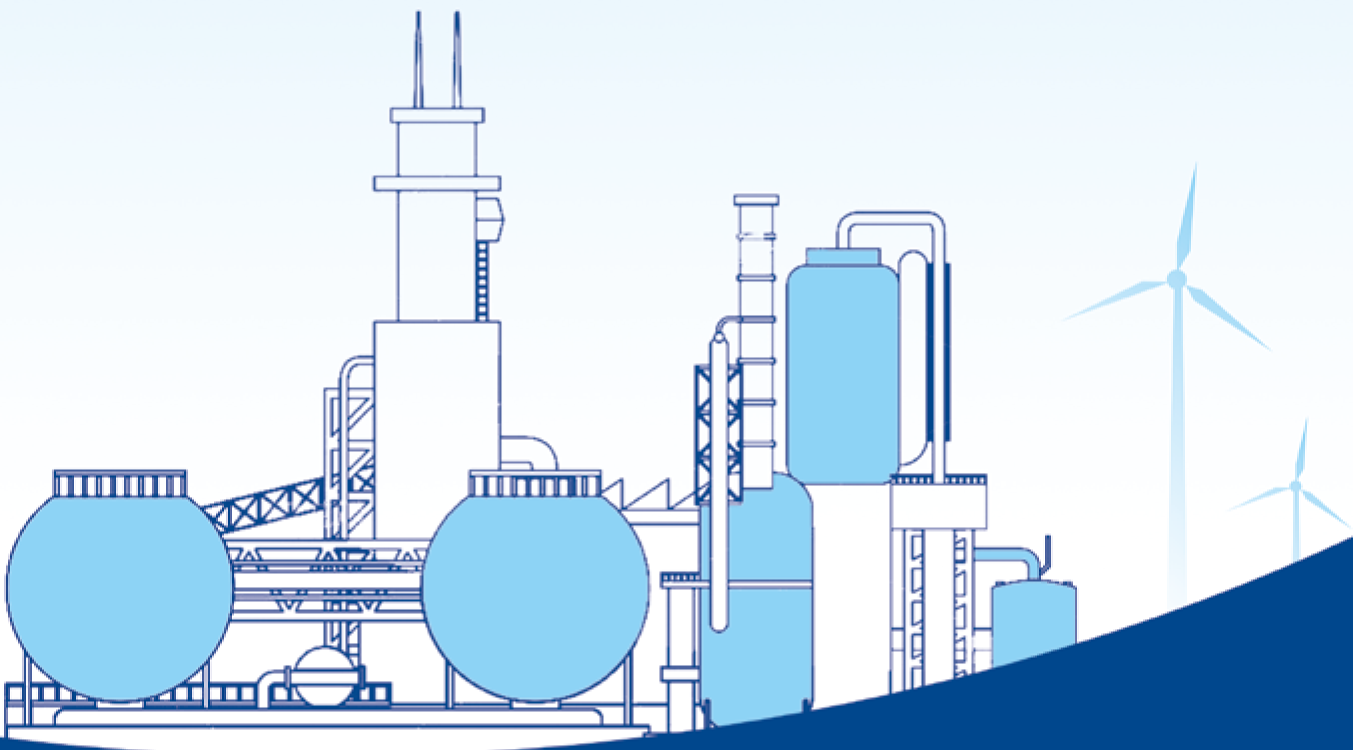


Fig. 14 Overall Layout of Yangpu Thermal Power Plant and potential vacant area near the plant

Due to the existing spatial layout and land use planning within the Yangpu Thermal Power Plant site, there is insufficient vacant land available for constructing a full-scale CO_2 capture facility. However, outside the plant site, there remains an area of flat land. Should the addition of such a facility be required in the future, it will be necessary to apply for land use permission from the local government in accordance with relevant laws and regulations, and to complete the corresponding land approval procedures.

5
Synthesis and Strategic Pathways



5.1 Conclusions

The analysis presented in this report confirms that amine-based post-combustion capture stands as the only technologically ready pathway for the near-term, large-scale decarbonisation of NGCC power plants. This conclusion is underpinned by the following key findings:

1.Technological Maturity vs. Alternatives:

In the demonstrated absence of commercially viable alternatives for NGCC applications, amine-based PCC—with decades of industrial and pilot-scale development—is the sole option capable of achieving the high capture rates (90~100%) required for deep decarbonisation today. Alternative pathways, such as the Allam Cycle or solid adsorbents, remain either pre-commercial or unsuitable for the low CO_2 concentrations typical of NGCC flue gas.

2.Established but Unproven at NGCC Scale:

FEED studies provide a detailed blueprint, indicating that both retrofitting PCC to existing NGCC plants (dominant in the USA) and constructing new-build facilities (favoured in the UK) are technically feasible. However, these remain pre-commercial estimates. Recent data indicates that levelised capture costs are highly sensitive to load factor, ranging from approximately \$80/t CO_2 at high load factors to over \$212/t CO_2 at low load factors. Furthermore, macroeconomic shifts from 2020 to 2024 drove a significant increase in unit capture costs due to inflation and interest rates. The absence of long-term operational data from a commercial-scale NGCC+PCC facility means that real-world performance, solvent management costs, and operational flexibility under grid dynamics remain critical uncertainties.

3.High Capture Rates:

A Feasible and Necessary Target: Pilot and research projects have shifted the paradigm on capture rates. Initiatives like the UK's FOCUSS project address the critical challenge of maintaining high capture rates including during flexible operation with perhaps hundreds of starts and stops over a year. More fundamentally, work by the COGENT-Capture project at the Guangdong Carbon Capture Test Platform has demonstrated that through optimised process control (e.g., operating at the "inflection point"), achieving ~100% "added CO_2" capture (i.e., returning flue gas CO_2 to ambient air levels) is technically feasible without incurring a large increase in specific reboiler duty or capital cost. This makes pursuing the highest possible capture rates not just an environmental imperative but a technically and economically sound design goal for new projects.

4.Solvent Choice:	A Question of Risk, Not Radical Advantage: Independent comparative analyses suggest that the energy performance and cost differences between proprietary solvents and benchmark MEA for NGCC applications may be marginal when evaluated within a standardised framework. Moreover, energy consumption becomes progressively less important relative to capital cost as the load factor of the power plant decreases. The greater differentiator may lie in long-term solvent stability, degradation management, and environmental footprint—factors that can only be validated through sustained commercial or fully representative pilot operation. The experience from early coal-based projects cautions that actual solvent management costs can significantly exceed initial projections, at least at times.
5.Operational Flexibility is Critical:	For NGCC plants serving in a renewables-heavy grid, flexibility is not optional. The FOCUSS project demonstrates that solvent storage systems can maintain high capture rates during start-up, shutdown, and transient loads by decoupling absorption and stripping processes. Utilising wasted "early steam" during start-up sequences can further reduce the required solvent inventory and avoid electricity output penalties. Without such measures, the frequent cycling required for peak-shaving (e.g., hundreds of starts per year) would severely compromise annual capture performance.
6.A System-Critical Enabler, Not Just an Add-on:	For China and the UK, and indeed for any power system with high renewable penetration, decarbonised NGCC plants are not merely an option but a strategic necessity. They provide the critical firm, dispatchable capacity to ensure grid reliability alongside variable renewables. Therefore, deploying PCC on NGCC is not merely an end-of-pipe emission reduction tactic; it is a system-level investment in energy security and transition resilience.

5.2 Recommendations for Future Work

To accelerate the deployment of reliable, high-performance, and cost-effective NGCC+CCS, strategic efforts are recommended to focus on the following priorities:

1.Conduct Long-Duration Integrated Testing Prior to Commercial Scale-Up:	Before full-scale commercial deployment, dedicated pilot or demonstration projects should operate for a minimum of two years under realistic conditions. This extended testing period is essential to validate long-term solvent stability, capture system performance, and real-world O&M costs.
2.Enhance Operational Flexibility through Advanced Solvent Management and Control Strategies:	Develop integrated solutions to maintain high capture performance during plant start-up, shutdown, and rapid load changes. This includes: 1) Implementing a solvent storage system to improve capture efficiency during low-load or offline periods. 2) Establishing an advanced control system that enables real-time coordination between the NGCC and PCC units, allowing simultaneous optimisation of power output, heat integration, and CO_2 capture rate in response to grid signals.
3.Adopt 95~100% Capture Rate as the Performance Standard for New Projects:	New NGCC+CCS projects are advised to target a minimum capture rate of 95%, with a design goal of ~100% "added CO_2" capture (i.e., flue gas CO_2 concentration returned to near-ambient levels). This standard aligns with net-zero emission pathways.
4.Drive Down Capital Costs through Targeted Pilot-Scale Projects:	Significant opportunities remain to reduce the capital expenditure. Dedicated research through pilot projects should focus on modularisation, heat integration, alternative construction materials, and process intensification. Learning-by-doing and supply chain development from initial projects will be key drivers for cost reductions. More fundamentally, right-sizing capture equipment for expected operating ranges, duty cycles and electricity system fluctuations may also offer significant cost reductions through taking advantage of the special nature of the applications that are opening up for system balancing.
5.Enhance Policy and Market Support for Early Deployment:	Until economies of scale drive down costs, public support is critical. Governments and regulators should provide targeted financial mechanisms (e.g., grants, low-cost loans, or contracts-for-difference for captured CO_2) and strengthen carbon market signals to create a viable revenue stream and de-risk early commercial NGCC+CCS investments.

Acronyms

Acronym	FULL FORM
AECOM	AECOM (company name)
BASF	BASF (company name)
BECCS	Bioenergy with Carbon Capture and Storage
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CDR	Carbon Dioxide Removal
CERI	Clean Energy Research Institute (China Huaneng Group)
CHP	Combined Heat and Power
COGENT	COGENT-Capture (project name)
DACCS	Direct Air Carbon Capture and Storage
DESNZ	Department for Energy Security and Net Zero (UK)
DOE	Department of Energy (US)
FEED	Front-End Engineering Design
FOCUSS	Flexible Operation of Capture Using Solvent Storage
GE	General Electric
GHG	Greenhouse Gas
GW	Gigawatt
H_2	Hydrogen
HNC	HNC-7 (proprietary solvent)
IEAGHG	International Energy Agency Greenhouse Gas R&D Programme
IPCC	Intergovernmental Panel on Climate Change
ITCN	International Test Center Network for CCUS
LP	Low Pressure
MEA	Monoethanolamine
MHI	Mitsubishi Heavy Industries
MOF	Metal-Organic Framework
MW	Megawatt
MWe	Megawatt (electrical)
MWh	Megawatt-hour
NGCC	Natural Gas Combined Cycle

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