Capturing the value of LNG

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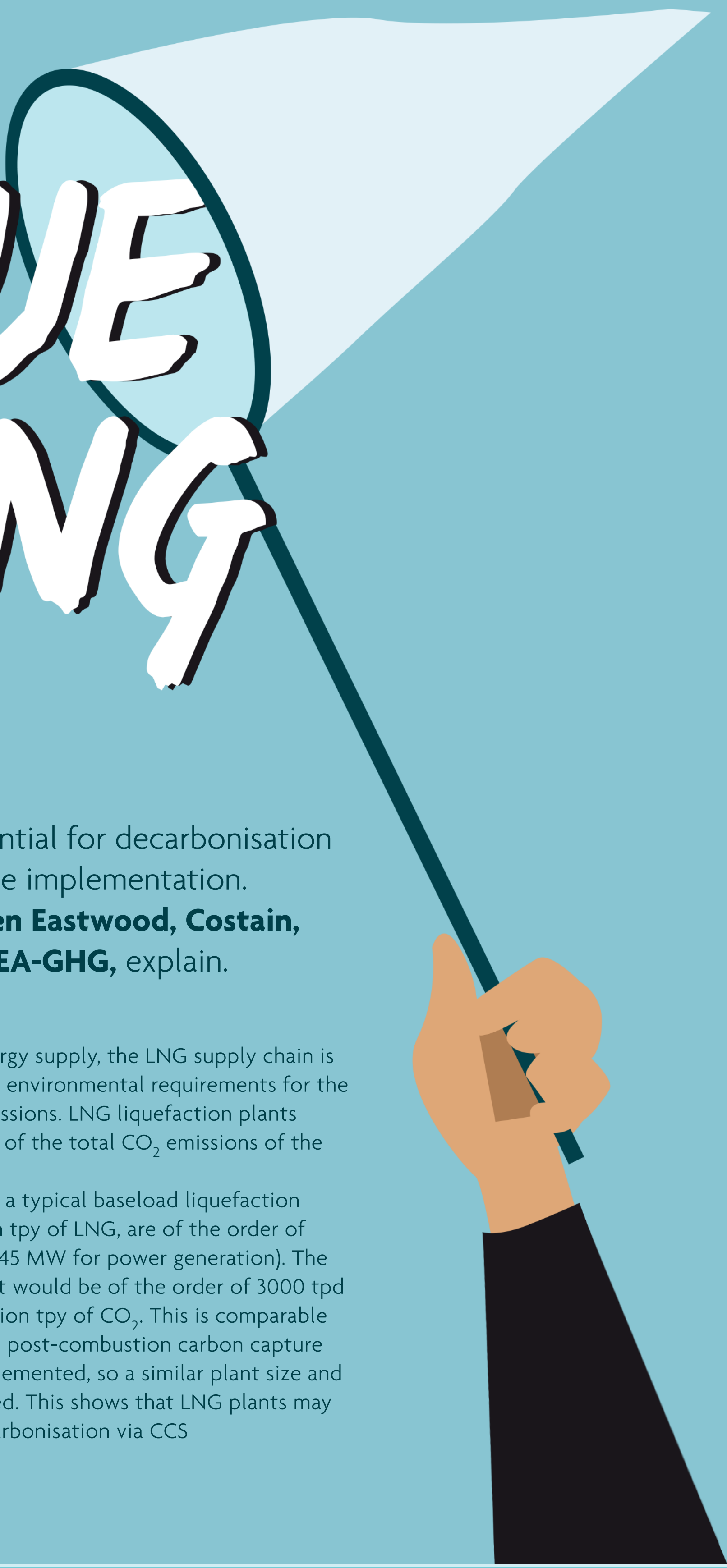

LNG plants may provide potential for decarbonisation via carbon capture and storage implementation. **Jorge Arizmendi-Sanchez, Ben Eastwood, Costain, along with Jasmin Kemper, IEA-GHG,** explain.

As a key contributor to global energy supply, the LNG supply chain is expected to be subject to global environmental requirements for the reduction of greenhouse gas emissions. LNG liquefaction plants produce a significant proportion of the total CO_2 emissions of the LNG supply chain.

Representative power requirements of a typical baseload liquefaction plant, with a nominal capacity of 5 million tpy of LNG, are of the order of 230 MW (~185 MW for mechanical drive, ~45 MW for power generation). The required capacity of the CO_2 capture plant would be of the order of 3000 tpd of CO_2, equivalent to approximately 1 million tpy of CO_2. This is comparable to existing full-scale capture plants where post-combustion carbon capture and storage (CCS) projects have been implemented, so a similar plant size and associated investment could be anticipated. This shows that LNG plants may provide an opportunity for potential decarbonisation via CCS implementation.

CO_2 sources and emissions

The gas turbines driving the refrigerant cycle compressors and in power generation service are typically the major emmiters of CO_2. Based on the typical range of baseload liquefaction specific power of 0.3 – 0.4 kWh/kg and the performance of gas turbine drives, CO_2 emissions for LNG plants are typically 0.2 – 0.28 t of CO_2/t of LNG for industrial heavy-duty gas turbines. The emissions can be reduced by approximately 25% if aeroderivative gas turbines are used.

CO_2 is separated from the feed gas in an acid gas removal unit (AGRU) to avoid solidification in the liquefaction process. Infrastructure for sequestration of CO_2 is potentially limited to compression and purification (mainly dehydration) of the low-pressure CO_2 that is otherwise vented. This assumes a low proportion of H_2S and sulfur compounds. Otherwise, the acid gas stream from the AGRU may need to undergo incineration, resulting in high levels of oxygen and SO_2 and requiring additional processing to purify the residual CO_2 stream.

Reservoir gas fed to liquefaction terminals typically contains around 2 mol% of CO_2. Higher CO_2 content in feed gas will result in substantially larger volumes of CO_2 being vented, providing a good basis upon which a case for CCS implementation can be built.

Combined emissions are in the approximate range of 0.3 – 0.4 t of CO_2/t of LNG for typical plants with relatively low CO_2 content in feed gas (<2 mol%) and up to approximately 0.7 t of CO_2/t of LNG for plants with a high CO_2 content (14 mol%, representative) in feed gas (Figure 1).

Table 1. Economic evaluation summary

		2 mol% CO_2 in feed gas	14 mol% CO_2 in feed gas
CO_2 emissions (million tpy)	From AGRU	0.27	1.86
	From fuel gas combustion	1.09	1.09
	Total LNG plant	1.35	2.95
	Associated to capture plant	0.18	0.18
	Captured and stored	1.24	2.84
	Emitted[1]	0.29	0.29
	Avoided	1.06	2.66
CO_2 capture from AGRU and post-combustion	Capital cost[2]	€755 million	€872 million
	Operating cost[3, 4]	€567 million	€783 million
	Specific capture cost	€42.5/t of CO_2	€23.3/t of CO_2
CO_2 capture from AGRU only	Capital cost[2]	€30 million	€144 million
	Operating cost[3, 4]	€68 million	€384 million
	Specific capture cost	€14.7/t of CO_2	€11.3/t of CO_2

Notes:
[1] CO_2 emission costs excluded in this estimate.
[2] Engineering, equipment, bulk materials, construction, contingency, fees, interest, capital spares, chemicals, start-up costs, owner's costs.
[3] Lifetime costs (25 years) including insurance, taxes and fees, operation and maintenance, power, steam, chemicals, waste disposal, CO_2 transport and storage.
[4] Assumed gas price is €6/GJ and discount rate of 8%. For other assumptions, refer to IEA-GHG study reference IEA/CON/16/235.

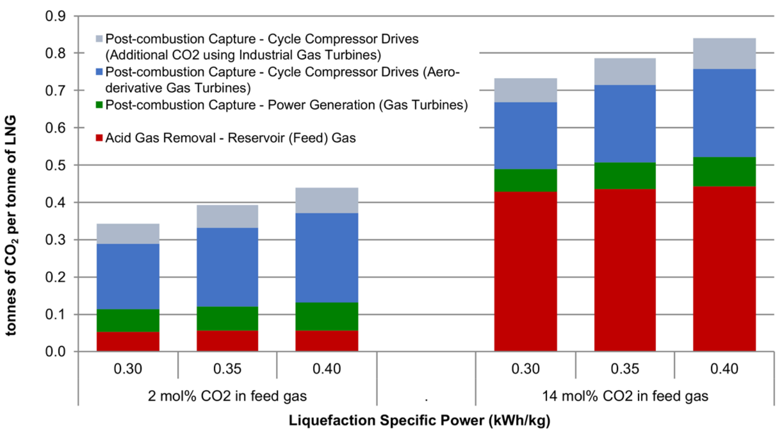

Figure 1. Representative CO_2 emissions from an LNG liquefaction plant.

CO_2 capture routes and technology

Based on the nature of the LNG industry, only well-proven technologies are expected to be considered for CO_2 capture in LNG plants, with schemes that minimise risk of disruption to LNG production.

Post-combustion capture is considered to provide comparable performance to other routes (i.e. oxyfuel and pre-combustion), with reduced technical risk and process complexity. Post-combustion capture can be installed without affecting the availability of the liquefaction process. This route requires a minimum number of modifications to the liquefaction plant – mainly consisting of the installation of tie-ins, and potentially the installation of additional waste heat recovery (WHR) on gas turbine exhausts – hence reducing risk. This makes post-combustion capture appropriate for new LNG plants or as a retrofit to existing plants.

The technologies with the highest potential for immediate implementation are chemical absorption processes. These are proven technologies, with the main disadvantage being the energy requirements to regenerate the solvent. However, the heating duty could be provided by WHR, which should be available in excess in an LNG plant. Perceived operational challenges, such as solvent degradation, solvent volatility and losses, corrosion, etc., can be managed within acceptable limits using solvent formulations that are commercially available.

CO_2 capture plant integration

In a post-combustion capture scheme, an interface between the gas turbines' flue gas exhaust ductwork and the inlet to the CO_2 capture plant is required. Considerations include the installation of tie-ins and large interconnecting flue gas ductwork, which may require substantial modifications to pipework and structures on existing plants or considerable space allowance for new build 'capture-ready' plants.

Experience with full scale post-combustion capture plants shows that the footprint required by the capture plant and associated systems (e.g. cooling, power generation or ducts) is significant and comparable to the core processes. For new build applications, issues associated with the layout and configuration of the plant can be tackled by considering the location of emission sources relative to the capture plant, the selection of gas turbine type, etc. Nevertheless, these factors will add complexity and costs to the LNG plant design when compared to the design of a conventional LNG plant.

If additional WHR units need to be installed, the plant design must consider the increased backpressure in the gas turbine outlet, which will impact the performance and efficiency of the liquefaction process and reduce plant capacity.

The design (machinery selection) and operation of shared power generation facilities at part load, during periods when the capture plant is not operated, needs to be considered.

The expected size of the CO_2 capture plant for a typical baseload liquefaction train is comparable to the largest CO_2 capture plants currently operating, with equipment near physical construction limits (particularly the cross-sectional area of columns). Therefore, a scheme in which a single CO_2 capture plant processes the full volume of flue gas from multiple LNG trains is not anticipated.

Economic evaluation

Cost estimates have been developed for capture and compression of the CO_2 separated from feed gas (by AGRU) and flue gases (post-combustion capture) for a 4.6 million tpy LNG plant based on a C3MR process using two Frame 7 gas turbines as refrigerant compressor drives, (as being representative of baseload LNG train designs). Power generation is assumed to be 25% of the cycle power. All process heating is supplied by WHR from gas turbines.

Cost estimates do not include the capital cost associated with the transport and storage infrastructure (assumed existing), but a specific operating cost of €10/t of CO_2 is included. This cost can differ substantially as transport and storage schemes vary depending on factors such as the proximity and nature of storage sites, opportunity for enhanced oil recovery, etc.

Estimated emissions and costs are summarised in Table 1. A reduction in specific capture costs for increased CO_2 in feed gas is due to the contribution of significant volumes of CO_2 from the AGRU (Figure 1) with lower specific costs associated to compression and purification. The specific capture cost can be significantly reduced if the scheme only considers compression and purification of CO_2 from the AGRU.

LNG costs for a range of CO_2 emission costs (i.e. CO_2 tax) are shown in Figure 2. On the basis of emission costs, implementation of CCS would only be financially attractive for minimum CO_2 emission costs of the order of €120/t of CO_2 for a representative LNG plant with 2 mol% CO_2 in the feed gas. Considering feed gas with 14 mol% CO_2 shows increased potential, as the minimum CO_2 emission cost that justifies capture is of the order of €60/t of CO_2 due to the emission cost savings associated with the significant volumes of CO_2 vented from the AGRU.

Current world emission policies set CO_2 tax at a relatively low value (if any), with most emissions currently priced at less than approximately €10/t of CO_2. Implementation of post-combustion CCS would only occur for either significant CO_2 tax increases or by drivers other than plant economics, such as environmental regulations dictating the requirement for CO_2 capture.

When the CCS scheme only considers sequestration of the CO_2 from the AGRU, the minimum emission cost required to justify the scheme is of the order of €30/t of CO_2. This level of CO_2 tax is within current environmental policies in some regions (such as Norway and Finland), which shows the potential of this route for the implementation of CCS.

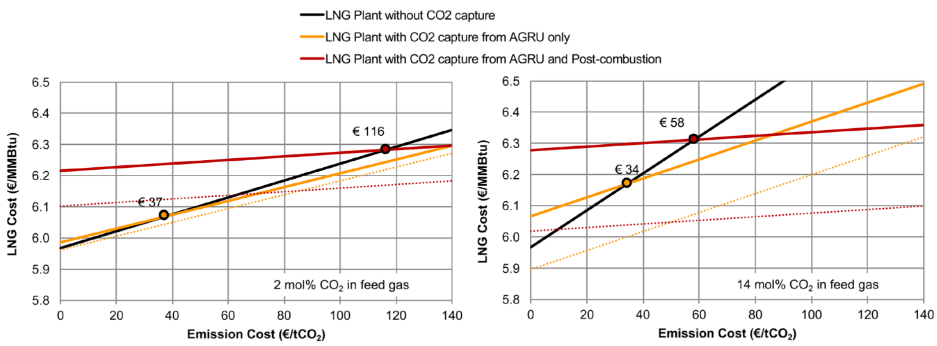

Figure 2. LNG production cost based on representative CAPEX of US$1200/tpy of installed LNG capacity, annual OPEX equal to 3% of CAPEX, and a nominal cost of US$6/million Btu (€4.8/million Btu) to cover transportation, regasification and profit. The dotted lines show the benefit of a tax credit of US$50/t of CO_2 (€40/t of CO_2) for 12 years.

The prospects of CCS could also be benefited by CO_2 tax credits, such as the US 45Q tax incentive offering US$50/t (€40/t) of CO_2 captured in underground storage. This would potentially make the economics of CCS of CO_2 from the AGRU feasible, regardless of emission cost (Table 1).

Potential for CO_2 capture

Despite incremental performance improvements being delivered by capture technologies, CO_2 capture remains an energy-intensive process. LNG plants have significant potential in this regard as there is usually scope for additional WHR at the exhaust of gas turbines in mechanical drive or power generation service that would provide the required process heating at minimal cost (assuming WHR is installed).

Sequestration of CO_2 vented in the AGRU will play a major role in the implementation of CCS in LNG plants having potential in terms of technical feasibility, footprint, cost and impact on overall project feasibility, particularly on financing, compared to post-combustion capture. Project costs (excluding transport and storage infrastructure) are one order of magnitude lower than the full scale post-combustion capture costs.

New build plants are expected to have greater potential for CCS due to the ability to optimise the plant design to facilitate the incorporation of the CCS scheme. While permitting reduction in costs, capture-ready plants will also encourage implementation of CCS by providing design allowances (such as tie-ins, allocated plot space and spare power generation capacity) to facilitate installation of future CO_2 capture plants. Implementation of CCS schemes as retrofits on existing (non-capture ready) plants appears to be difficult due to technical challenges and the impact on the LNG production economics.

In addition to the demonstration of technical feasibility, a number of drivers would need to be present for a CCS scheme to be realised, including the need to comply with environmental regulations, penalties on emissions (i.e. CO_2 tax), the availability of local storage, availability of funding and financial incentives, and other conditions contributing to the commercial feasibility of the overall scheme.

The technical and commercial feasibility, leading to successful implementation of a CCS scheme, should be considered early, when the economics of the LNG production scheme are developed. The potential implementation of CCS in LNG plants could be realised by a phased development, with sequestration of CO_2 vented from the AGRU being a precursor to full scale CCS, to make financing feasible and to manage technical and commercial risks. Post-combustion CCS would then be implemented via capture-ready plant designs.

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