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Cost of small-scale dispatchable CO_2 capture: techno-economic comparison and case study evaluation

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Abstract:

Dispatchable power sources are crucial for electricity system stability and security of supply. Currently, the United Kingdom uses small-scale (<50 MWe) gas turbines to provide this function. To ensure we reach Net-Zero emissions by 2050, these small-scale dispatchable generators will require CO_2 abatement; however, limited studies focus on these forms of power generation.

In this work, we use process models developed in our previous studies, to calculate the levelised cost of electricity (LCOE) for a small-scale gas turbine equipped with Carbon Capture and Storage (CCS). The results show that the inclusion of CCS for these dispatchable generators increases the LCOE from 172 £/MWh to 514 £/MWh, almost tripling the cost of electricity. This is due to economies of scale and the low capacity factor. As these generators operate for less than 20% of the year, the levelised cost is drastically higher than other forms of low-carbon power. Dispatchable power is usually more expensive due to the small plant size and transient operation, and including CCS exacerbates this issue. Future work should focus on alternative forms of CO_2 capture (designed specifically for small-scale gas turbines) and different dispatchable power generation, i.e., hydrogen and energy storage.

Key Words: Post-Combustion Capture; CO_2 Adsorption, CO_2 Absorption; CCS, Techno-economic assessment

1. Introduction

With the new targets for the United Kingdom (UK) to reach Net-Zero greenhouse gas emissions by 2050, all forms of power generation will need to be low/zero/negative carbon. Whilst nuclear and renewables are a clear way to avoid anthropogenic CO_2 emission, these types of generators are inflexible and intermittent [1]. For system security and reliability of electricity supply, it is important to have dispatchable and quick-response generators. Dispatchable power refers to generators that can be started up and shutdown quickly, to balance the supply and demand of electricity [2]. The relatively simple design, quick start-up times, comparatively low CO_2 emissions, and high operational flexibility of open-cycle gas turbine (OCGT) power plants has made them attractive options for providing system security [3, 4]. National Grid (NG) has the Short-Term Operating Reserve (STOR) which holds OCGT capacity, readily available for when there are imbalances on the system [5]. Alternate technologies such as energy storage and hydrogen turbines will increase in capacity over the coming decades, as they can consume an oversupply of renewable energy and resupply when capacity is needed; however, NG states there is still the need for dispatchable thermal generation via Gas-CCUS irrespective of the energy pathway taken [6]. As the UK energy system transitions to using more renewable energy sources, OCGT capacity is expected to increase to provide stability and security of supply [7, 8]. They will also play an important role in other international energy markets, such as Australia [9, 10], Germany [11], Saudi Arabia [12], and South Korea [13]. In order to meet the emission reduction targets, the UK's Committee on Climate Change (CCC) has recommended that unabated gas power generation should be phased-out by 2035 [1]. With the expected growth of small-scale OCGTs, it is imperative to investigate CO_2 capture for these systems. Currently, sources less than 50 MW, covered by the Medium Combustion Plant Directive (MCPD), are not required to be Carbon Capture and Storage (CCS) ready [14]. Thus, limited sources have studied small-scale CCS. However, an expansion of the Carbon Capture Readiness (CCR) requirements could see these generators also encompassed in the Industrial Emissions directive (IED) [15].

Danaci et al. [16] showed the cost of capture as a function of gas composition and flowrate, in which they highlighted the higher cost of capture when dealing with low flowrate (<10 kg/s) and low CO_2 composition (<10 mol % CO_2) systems; unfortunately, this is precisely where OCGTs operate. To the best of the authors' knowledge, no studies within the literature have analysed the cost of small-scale CO_2 capture for OCGTs.

Hence, we combine the process models developed in our previous works: Monoethanolamine (MEA) absorption [17], vacuum-pressure swing adsorption (VPSA) [18], and CO_2 compression [19], to investigate the cost of small-scale CO_2 capture. All of these studies have focused on CO_2 capture for OCGT power generators with a high degree of transient operation Amine absorption using 30 wt.% MEA is considered the benchmark CO_2 capture technology for post-combustion capture (PCC); hence, it forms the basis of this techno-economic assessment. Adsorption using zeolites is chosen for comparison as it is close to commercialisation with a large quantity of research supporting its development [20]. Herein, the process models are used within the economic framework of levelised cost of electricity (LCOE) to calculate the cost of the major pieces of equipment and the utility requirements. The main objectives are to:

- Analyse historical OCGT generation data.
- Develop an economical model for OCGT power generation with CCS.
- Compare MEA and VPSA for OCGT+ PCC.
- Compare OCGT+PCC against other low-carbon energy generators

The purpose of this paper is to highlight the cost of including CO_2 capture on small-scale fossil-based power generation. These generators are commonly overlooked when discussing pathways to Net-Zero; therefore, this study includes a comparison to other low-carbon and dispatchable generators, in order to highlight the feasibility and worthwhileness of incorporating these generators in future energy systems.

1.1. Power Generation

Gas turbines typically combust natural gas, producing a flue gas containing 1-5 vol.% CO_2 [21]. In order to be considered a low-carbon power source, the gas turbine requires PCC and downstream conditioning, transportation, and storage [2].

It is important to analyse the real world behaviour of OCGT power generation, and a potential trend for future generation can be further extrapolated. The Balancing Mechanism Reporting Service (BMRS) provides operational data for power generation and demand in Great Britain (GB). Figure 1 shows the contour plots for OCGT generation each day in January from 2017 to 2022 [22]. OCGTs on the GB electricity grid have highly sporadic operation and mainly operate in the evenings and during the colder months, coinciding with the peak demand on the system. January is typically the busiest month for OCGT power plants. Wilkes et al. [17] showed the daily OCGT generation between 2016-2019, which provided comparable results and easily explainable operational patterns. Interestingly, between 2020 and 2022, OCGT operation becomes even more irregular. The majority of the time OCGTs contributed <100 MWe to the grid, however, over brief periods almost 1 GW of OCGT power was dispatched. The data shows that OCGTs are mainly dispatched during peak periods (green zones on Figure 1), but they also come on infrequently during the rest of the day. This implies that the 'worst-case scenario' used in [17] and [18] might be a regular occurrence for future OCGT plants.

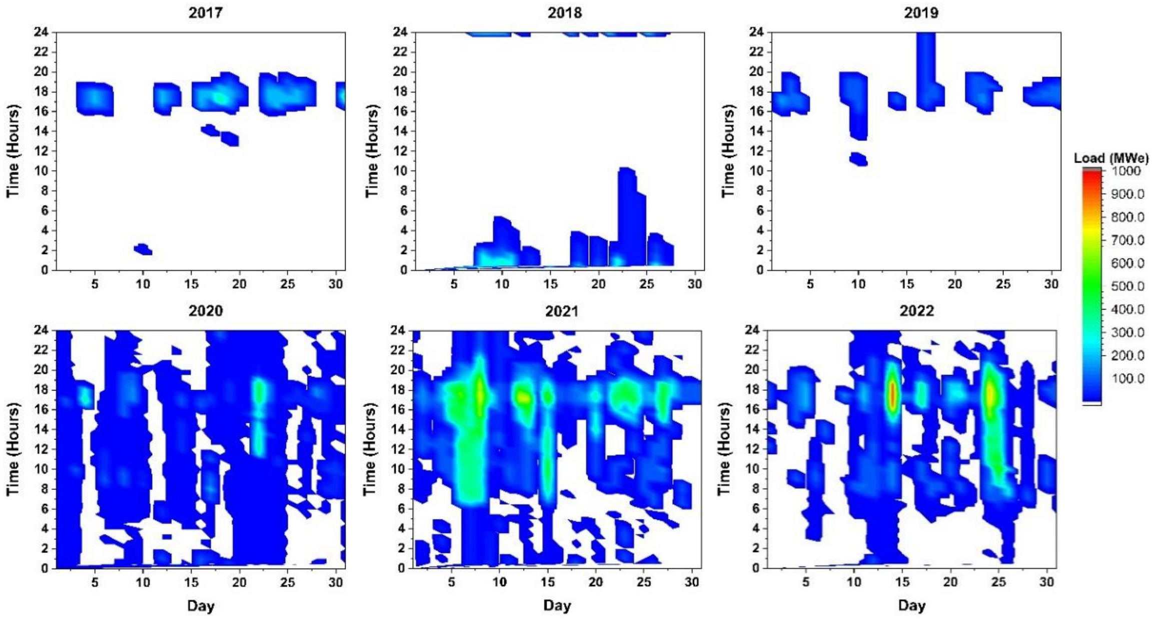

Figure 1: Daily OCGT generation for January between 2017-2022, raw data sourced from [22].

The total amount of energy generated each January by OCGT power plants in GB varies annually. Figure 2 shows there is no pattern to OCGT generation, which ranged between 3580-25897 MWh over the past 6 years. The maximum half-hourly OCGT load decreased from 390 MWe in 2017 to 164 MWe in 2019, which then steadily increased to 949 MWe in 2022. Other studies have highlighted the possibility of OCGT growth [7], but not at this rapid rate. On the 14th of January 2022, OCGT power plants provided 949 MWe or 2.21% of the total electricity generated during that settlement period in GB. Although this might seem insignificant, it indicates a potential bottleneck for the energy system to reach Net-Zero targets by 2050. Currently, small-scale fossil power plants are not required to be carbon capture ready; but in the future, it is highly likely small CO_2 emitters will also require abatement. Yet, to the authors' knowledge there are no studies that look at the cost of incorporating CO_2 capture on these small-scale emitters.

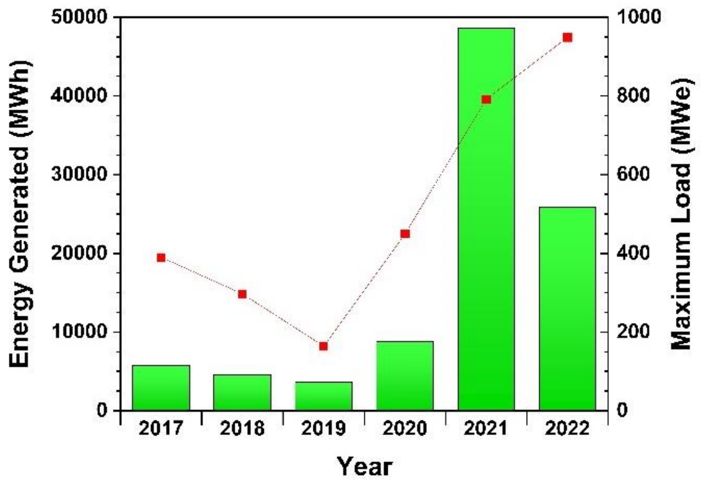

Figure 2: Total amount of energy generated and maximum load of OCGT power plants in January between 2017 and 2022, raw data sourced from [22]

1.2. Post-Combustion Capture

In order to prevent changing the combustion dynamics of the gas turbine, the CO_2 needs to be removed post-combustion. Thus, flue gas from the gas turbine enters the capture plant and the captured CO_2 is then conditioned ready for pipeline transportation. An MEA plant, shown in Figure 3, consists of an absorption column to remove CO_2 from the flue gas using MEA as the solvent, a stripping column to desorb the captured CO_2, a condenser to produce CO_2, a reboiler to ensure the stripping temperature is maintained, and a heat-exchanger to maximise the process efficiency. More information on the scaled MEA process model can be found in our earlier work [17] and in the reference case study used for model validation [23]. The VPSA plant, shown in Figure 4, consists of two stages each with two adsorption columns packed with Zeolite 13X, two flue gas blowers to pressurise the columns to 1.5 bar, and four vacuum pumps to depressurise and desorb CO_2. More information on the scaled VPSA process model can be found in our earlier study [18]. Both of the capture plants are based on pilot studies, which showed exceptional performance in terms of capture rate and product purity.

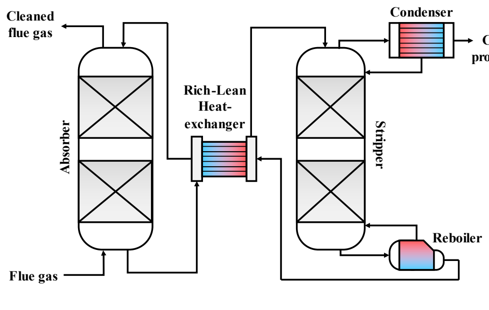

Figure 3: Simple MEA capture plant diagram

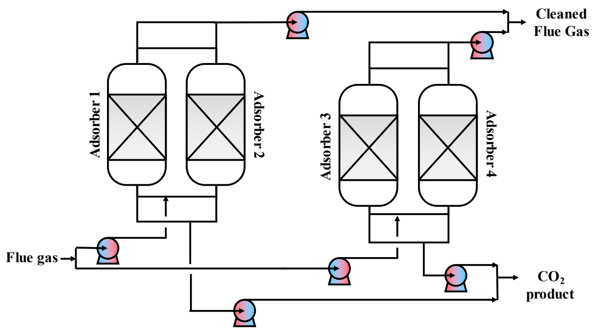

Figure 4: Simplified VPSA capture plant diagram

The conditioning train, shown in Figure 5 includes four compression stages that raises the CO_2 stream pressure to 111 bar, four knock-out drums and one dehydration unit which ensure the moisture content is 50 ppm, and four interstage coolers that decrease the CO_2 stream temperature prior to each compression stage to maximise the compressor efficiency. More information on the conditioning train can be found in our previous work [19] and the reference case study used for model validation [24].

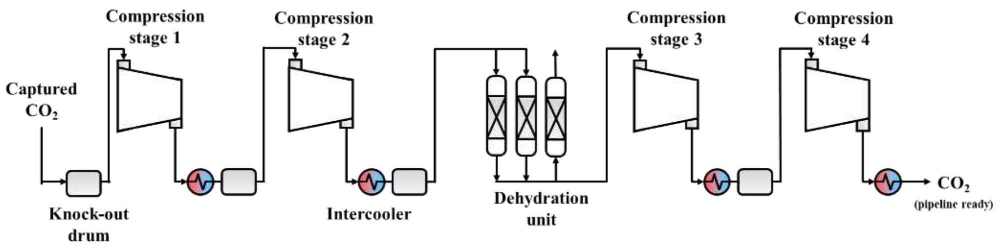

Figure 5: Simplified CO_2 conditioning plant diagram

2. Economic Model

In order to economically evaluate the power generation asset, several plant characteristics and analytic metrics need to be defined. Included in the economic comparison is the cost of generating electricity from an OCGT power plant, capturing the CO_2 from the flue gas, and conditioning the captured CO_2 stream ready for pipeline transportation. The cost of CCS for power generation plants can be defined as the difference in cost between a plant without CCS (subscripted with 'ref') and a plant with CCS (subscripted with 'CCS') [25]. The main capture metric used is the cost of CO_2 avoided (CCA), as we include the compression and conditioning train into the cost model.

$$CCA = \frac{(LCOE)_{ccs} - (LCOE)_{ref}}{\left(\frac{CO_2}{MWh}\right)_{ref} - \left(\frac{CO_2}{MWh}\right)_{ccs}} \qquad 1$$

Where the CO_2/MWh ratio is the carbon intensity of the process, i.e., the amount of CO_2 (tonne) released into the atmosphere per unit power generated (in MWh). The levelized cost of electricity (LCOE), calculated using Equation 2 [26], is the discounted lifetime cost of constructing and operating a power generation asset. It is the sum of the net present value (NPV) of costs divided by the NPV of electricity generated and then sold.

$$LCOE = \frac{\text{NPV of total costs}}{NPV\ of\ electricty\ generation} = \frac{\sum_t \left(\frac{\mathrm{TCC_t}}{(1+r)^t} + \frac{\mathrm{FOM_t}}{(1+r)^t} + \frac{VOM_t}{(1+r)^t}\right)}{\sum_t \frac{(\text{net electricty generated})_t}{(1+r)^t}} \qquad 2$$

Where TCC is the total capital cost, FOM is the fixed operating and maintenance cost, VOM is the variable operating and maintenance cost, r is the discount rate, and t is the time period.

To enable a comparison with sources that do not include the cost of compression in their analysis, the cost of CO_2 capture (CCC) metric is also used [27]:

$$CCC = \frac{(LCOE)_{cc} - (LCOE)_{ref}}{\left(\frac{CO_2}{MWh}\right)_{cc}} \qquad 3$$

Where the subscript 'CC' only includes the capture technology in the LCOE calculations. Assumptions required to calculate the LCOE, CCA and CCC are:

- Plant location – Yorkshire, England.
- Plant lifetime – 25 years.
- Construction time – 2 years.
- Start of construction – 2019.
- Discount rate – 7.8% for the proven conventional technologies and 8.9% for higher risk novel technologies [28].
- Capacity factor – 17.14 % (based on 1500 hours annual operating time [29]).
- Carbon price - £21.70/tCO_2 (set price for 2021 from [28]).

Within BEIS's report benchmarking state-of-the-art and next generation technologies for electricity supply [28], the carbon price increases from £21.6/tCO_2 in 2017 to £233.3/tCO_2 in 2050. For simplification of the net present value (NPV), the carbon price is set at the 2021 price at £21.70/tCO_2, i.e., the first year of operation.

2.1. Total capital cost

The TCC is the cost of designing, constructing, and installing the plant. To estimate the major equipment cost, the most accurate method is a direct quotation from original equipment manufacturers (OEMs) [30], however, this is difficult to obtain and requires in-depth and accurate equipment sizing for all major components. From Towler & Sinnott [31] the capital investment consists of:

- Inside battery limits (ISBL) investment, the direct and indirect equipment costs.
- Offsite battery limits (OSBL) investment, the modifications, and improvements to site infrastructure.
- Engineering and construction costs.
- Contingency costs.

As an alternative to directly contacting equipment suppliers, equipment sizes (based on the scaled process models) are used with cost correlations to work out purchased equipment cost (PEC) delivered but not installed:

$$PEC = \sum_{1}^{total} E_i \qquad \forall i = 1 \ldots \ldots total \tag{4}$$

Where the individual equipment cost (E_i) is based on Equation 5 from Towler and Sinnot [31]:

$$E_i = a + bS^n \tag{5}$$

Where S is the sizing factor specific to each piece of processing equipment, and a, b, and n are cost factors found in Towler & Sinnot [31]. The calculated prices ($) are for 2010, and to scale to the current day the following equation is used [32]:

$$E_{\mathrm{i}}^{2019} = E_{\mathrm{i}}^{2010}\left(\frac{F^{2019}}{F^{2010}}\right) \tag{6}$$

The Chemical Engineering Plant Cost Index (CEPCI) for 2010 is 551 (F^{2010}) and for 2019 is 607.5 (F^{2019}) [33]. The purchased equipment cost requires an installation cost from Couper et al. [34]. Chauvel et al. [35] proposed a method that uses observed relationships of process unit investments, summarised in Table 1. The method uses the ISBL, which is the cost of the main process equipment and their installation. This method was used by Le Moullec and Kanniche [36], Abu-Zahra et al. [37] and Alhajaj et al. [38] for the techno-economic analysis of absorption-based CO_2 capture.

Table 1: Capital cost relationships [35]

Capital cost factor	Code	Relationship	
Purchased equipment cost (PEC)	C_1	See Equation 4	
Instrument cost (I)	C_2	$C_2 = \sum_i^n I_i$	7
Direct equipment cost (DEC)	C_3	$C_3 = \sum_i^n \mathrm{E}_i F_E + \sum_i^n I_i F_I$	8
Indirect equipment cost	C_4	$C_4 = \mathrm{C}_3 \times 0.31$	
Inside battery-limits investment (ISBL)	C_5	$C_5 = C_3 + C_4$	
Off sites	C_6	$C_6 = C_3 \times 0.31$	
Process unit investment (PUI)	C_7	$C_7 = C_5 + C_6$	
Engineering	C_8	$C_8 = C_7 \times 0.12$	
Paid-up royalties	C_9	$C_9 = C_5 \times 0.07$	
Process book	C_{10}	$C_{10} = 265{,}000\ US\$\ in\ 2004$ [a]	
Facility capital cost (FCC)	C_{11}	$\mathrm{C}_{11} = C_7 + C_8 + C_9 + C_{10}$	
Initial charge of feedstock's	C_{12}	$\mathrm{C}_{12} = Feedstock\ required \times Cost$	
Interest during construction	C_{13}	$\mathrm{C}_{13} = \mathrm{C}_{11} \times 0.07$	
Start-up costs	C_{14}	$\mathrm{C}_{14} = 1\ month\ of\ operating\ costs$ [a]	
Working capital (WC)	C_{15}	$\mathrm{C}_{15} = 1\ month\ of\ operating\ costs$ [a]	
Total capital cost (TCC)	C_{16}	$\mathrm{C}_{16} = \mathrm{C}_{11} + C_{12} + C_{13} + C_{14}$	

[a] [38]

The TCC calculations vary depending on the literature referenced and are directly linked to their respective FOM and VOM calculations. VOM is based on process requirements, and FOM uses factors to calculate depreciation, maintenance, taxes, insurance, and overhead [39].

2.2. Fixed and variable operating and maintenance costs

Similar to the TCC, the FOM and VOM can be calculated using a factorial approach. Sinnott [39] explained that the division between FOM and VOM is subjective and particular to an organisation's practice. The operating cost calculation used in Chauvel et al. [35] is shown in Table 2. In the absence of actual data, the labour costs are based on the number of personnel required, assumed to be 4.5 people + 20% for supervision. The utilities cost is dependent on the process requirements, and the local cost of those utilities. Electricity costs incorporate the energy demand from primary process equipment (boilers, heat exchangers, pumps, blowers, compressors, etc.) and are based on energy balances and flow diagrams [39].

Table 2: Operating costs relationships [35]

Operating cost factor	Code	Relationship
Raw materials	O_1	Based on process flow diagram
Electricity	O_2	Based on process requirements
Fuel	O_3	Based on process requirements
Cooling water	O_4	Based on process requirements
Steam	O_5	Based on process requirements
Utilities	O_6	$O_6 = O_2 + O_3 + O_4 + O_5$
Variable operating and maintenance cost (VOM)	O_7	$O_7 = O_6 + O_1$
Labour	O_8	$O_8 = Cost\ of\ 4.5\ \mathrm{people/day} + 20\%$
Maintenance	O_9	$O_9 = C_7 \times 0.04$
Taxes and insurance	O_{10}	$O_{10} = C_7 \times 0.02$
Overhead	O_{11}	$O_{11} = C_7 \times 0.01$
Financing working capital	O_{12}	$O_{12} = C_{15} \times 0.09$
Fixed operating and maintenance cost (FOM)	O_{13}	$O_{13} = O_8 + O_9 + O_{10} + O_{11} + O_{12}$

For the calculation of VOM, several utilities are required. The prices of these are shown in Table 3. The steam supplied to the MEA stripping column (solvent regeneration), is calculated as a water and electricity demand. The electricity demand is calculated from the specific energy demand (kWh/ tCO_2 or GJ/tCO_2) for each process (including conditioning), which is then multiplied by the quantity of CO_2 captured annually. The raw materials for the MEA and VPSA cases are replaced annually for ease of VOM cost calculation. The OCGT does not have a heat-recovery steam generator (HRSG), therefore, there is no steam demand included in Table 3. The OCGT plant cost is calculated using the same costing method as the capture plants, and is based on the cost per unit power generated. Parson Brinckerhoff [40] states the OCGT unit cost ranges between 533-719 £/kW; as such, this study assumes the OCGT unit cost is 628 £/kW.

The level of detail within the cost model determines the classification of the cost estimates, and classes have been defined by the Electrical Power Research Institute (EPRI) and Association for the Advancement of Cost Engineering (AACE). This economic model used within this study can be classified as an EPRI Class II, similar to AACE Class 3. This work is not considered EPRI Class I (simplified) as it includes general site conditions, geographic location, plant design, material flow, and major equipment specification. The equipment sizes are based on validated process models with up-to-date utilities and purchasing costs. Therefore, the project contingency range is 15-30% [41].

Table 3: Utility prices

Raw material/utility	Process	Price [a]	Source
Natural gas	OCGT	0.033 £/kWh	[42]
Electricity	MEA and VPSA	0.14 £/kWh	[43]
Cooling water	OCGT and MEA	1.39 £/m3	[44]
MEA solvent	MEA	5.0 £/L	[45]
Zeolite 13X sorbent	VPSA	1.5 £/kg	[46]

[a] prices are for 2020/2021

Both capture systems have the same flue gas input and end-point characteristics, creating a black-box in which the economic evaluation occurs. A Direct Contact Cooler (DCC) is used to reduce the temperature of the flue gas to the suitable inlet temperature for the capture systems. The transportation and storage costs of the captured CO_2 is assumed to be 19 £/tCO_2 [28]. Table 4 shows the system characteristics for the two systems. For more information on the individual unit operations please see the respective articles for the MEA [17] and VPSA plants [18].

Table 4: System characteristics for OCGT power generation with MEA or VPSA CO_2 capture.

	MEA	VPSA
Power generation	10.4 MWe OCGT	10.4 MWe OCGT
Fuel source	Natural gas	Natural gas
Gross heat rate (kJ/kWh)	10173	10173
OCGT thermal efficiency(%)	35.4	35.4
CO2 capture technology	Amine-based absorption	Vacuum-pressure swing adsorption
Solvent/Sorbent	30 wt.% MEA	Zeolite 13x
Capture rate (~%)	92.5	97.1
Flue gas flowrate (kg/s)	33.8	33.8
Flue gas CO_2 concentration (vol.%)	4.27	4.27
Specific energy demand (kWh/tCO_2)	1480	1460
Energy penalty for CO_2 capture and compression (%)	12.4	12.9
Power output (MWe)	9.12	9.06

Gibbins and Lucquiaud [47] highlight the importance of not artificially constraining capture level thresholds, as this then becomes the de facto maximum capture rate, i.e., there should be incentives to capture as much CO_2 as possible and not just meet regulatory guidelines. Hence, the capture rates shown in Table 4 are based on scaled process models designed to deliver similar operating conditions as their respective pilot studies.

3. Results

A major aspect of the TCC is the PEC, shown in Figure 6 for the MEA plant and Figure 7 for the VPSA plant, both include the cost for the conditioning train. The costs are for the total quantity of each process equipment. The breakdown of OCGT+PCC PEC is shown in Figure 8. The total PEC for both the MEA and VPSA plants excluding and including conditioning is 1.14 M£ and 3.87 M£, respectively. CO_2 conditioning accounts for 70.6% of the total PEC for both capture systems. The energy demand for the conditioning train significantly increases at low flowrates [19]. Similarly, the cost of the equipment per mass of fluid process is significantly higher at low flowrates. For the compressors, the cost is a function of the power requirement (kW) that is calculated in the conventional multistage compression model and depends on the flowrate of the CO_2 stream coming from the capture plant. All pieces of equipment are assumed to be made from stainless steel (due to corrosion issues in high CO_2 environments [48]) with a density of 7,500 kg/m, and all column walls are 2.5cm thick.

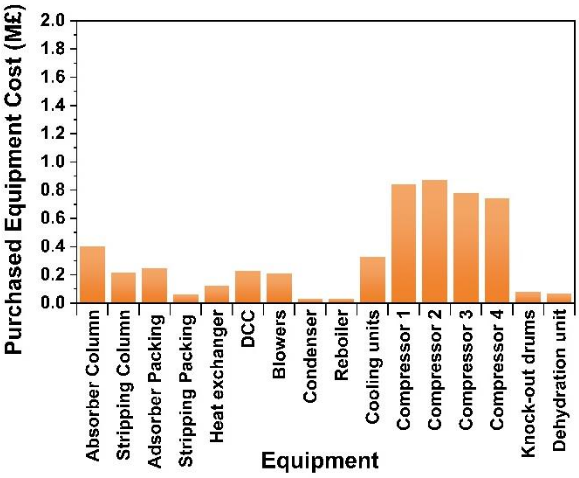

Figure 6: Purchased equipment cost for the MEA capture plant and conditioning train.

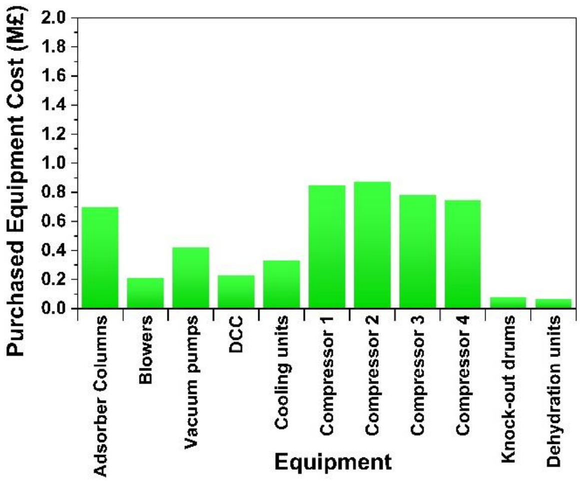

Figure 7: Purchased equipment cost for the VPSA capture plant and conditioning train.

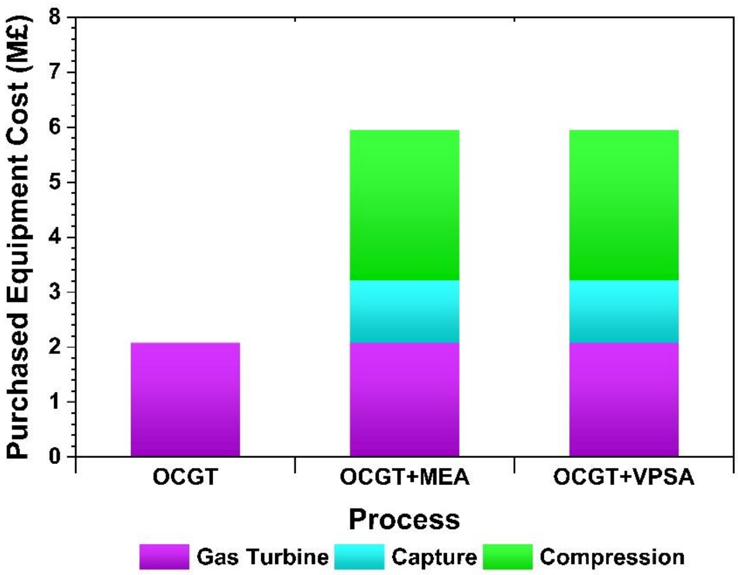

Figure 8: Purchased equipment cost breakdown for the OCGT, OCGT+MEA, and OCGT+VPSA plants.

Calculating the TCC requires the PEC for the main pieces of equipment. The CAPEX breakdown for the OCGT, MEA, and VPSA systems is shown in Table 5. Despite the MEA plant consisting of more processing equipment, the overall capture plant cost is cheaper than the VPSA plant. The contributing factor to the VPSA case is the vacuum pumps, which need to process large volumes of gas. In total, there are 2 blowers (for the flue gas) and 4 vacuum pumps (for the blowdown and evacuation steps) assumed for the large-scale system. Both cases have a similar PEC, but the instrumentation costs are higher in the VPSA case due to the high installation multiplier for blowers and vacuum pumps; from Couper et al. [34] the installation multiplier for blowers and vacuum pumps is 1.4 and 2.0, respectively. As there are multiple pumps in the VPSA system this increases the DEC and TCC.

Included in the MEA and VPSA plant costs are the costs associated with compressing and conditioning the CO_2 stream ready for pipeline transportation. The TCC for the OCGT is 6.53 M£, equating to 628£/kW.. Figure 9 shows the comparison between the OCGT, OCGT+MEA, and OCGT+VPSA plant costs, with and without CO_2 conditioning. Including CO_2 capture for small-scale OCGTs almost triples the initial capital investment. Although, half of the additional costs are associated with the conditioning train; these systems would therefore benefit from sharing the conditioning load or directly utilising the CO_2 on-site. Similarly, the technical evaluation of the conditioning train in Wilkes et al. [19] showed the drastically higher specific energy demand of low capacity systems. Hence, future studies should develop integrated power generation (for dispatchable use) and CO_2 utilisation plants, thereby removing the necessity of costly CO_2 compression.

Table 5: CAPEX breakdown for the OCGT, MEA, and VPSA systems

CODE	CAPEX	Units	OCGT	MEA	VPSA
C1	Purchased Equipment Cost	M£	2.08	3.87	3.87
C2	Instrument cost	M£	1.04	2.04	2.16
C3	Direct equipment Cost	M£	3.12	5.90	6.03
C4	Indirect equipment Cost	M£	0.967	1.83	1.87
C5	Inside battery limit Investment	M£	4.09	7.74	7.90
C6	Offsite battery limit investment	M£	0.967	1.83	1.87
C7	Process Unit Investment	M£	5.05	9.57	9.77
C8	Engineering	M£	0.606	1.15	1.17
C9	Royalties	M£	0.286	0.541	0.553
C10	Process data book	M£	0.006	0.006	0.006
C11	Fixed Capital Cost	M£	5.95	11.3	11.5
C12	Initial feed stock	M£	0.002	0.002	0.002
C13	interest during construction	M£	0.416	0.788	0.804
C14	Start-up cost	M£	0.169	0.290	0.297
C15	Total Capital Cost	M£	6.53	12.3	12.6
C16	Working capital	M£	0.169	0.290	0.297
	TCC	**M£**	**6.53**	**12.3**	**12.6**

The OPEX for the OCGT, MEA, and VPSA plants is shown in Table 6. The calculation of VOM requires input data from the scaled process models. The fuel (natural gas) cost is the quantity of energy required per annum (kWh/yr) multiplied by the price of natural gas for UK businesses, 0.033 £/kWh in March 2021 [42], also bearing in mind the thermal efficiency of the gas turbine. It is worth noting that the steam cost for MEA regeneration is included in the electricity cost and water demand. The electricity cost for the capture technologies is as follows:

- **MEA** – The primary energy demand comes from the solvent regeneration. The baseload results highlighted in [17] shows the specific energy demand is 1300kWh/tCO_2. The compression energy requirement is 179 kWh/tCO_2 [19].

- **VPSA** – The energy demand comes from the flue gas blower and vacuum pumps. The baseload results highlighted in [18] shows the specific energy demand is 1,280 kWh/tCO_2. The compression energy requirement is 186 kWh/tCO_2 [19].

These values are used to calculate the annual electricity demand for each process, and therefore the overall cost. The water demand for the OCGT is set at 3 L/MWh [49] and for MEA it comes from the process model set at 300 L/h.

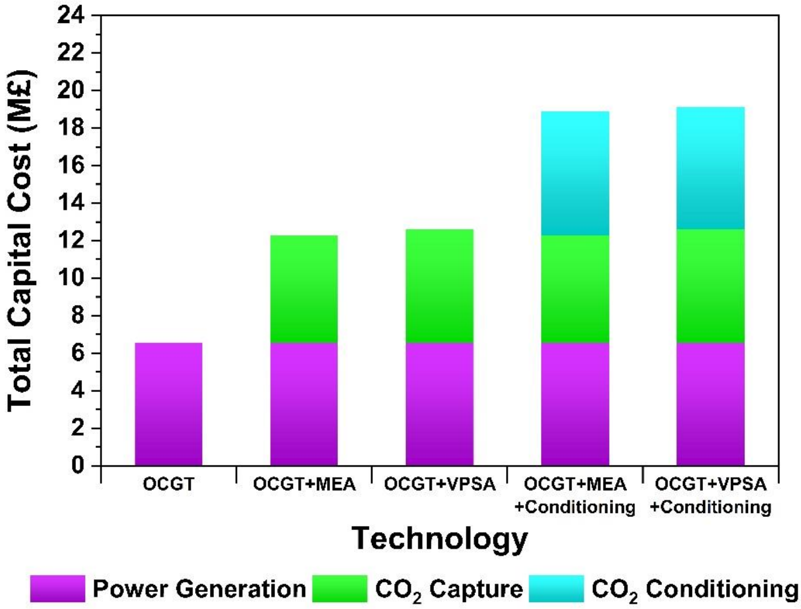

Figure 9: Total capital cost comparison for the OCGT, OCGT+MEA, and OCGT+VPSA plants, with and without CO_2 conditioning.

For the scaled MEA process, the quantity of solvent required is 44.8 t/yr, which costs £4.5/L at 1.02 kg/L [45]. For the scaled VPSA process, the quantity of Zeolite 13X is 131 t/yr, which costs 1.5 £/kg [46]. It is assumed that both capture materials require replacement each year, for simplification of the economic cash flows.

Table 6: OPEX breakdown for the OCGT, OCGT+MEA, and OCGT+VPSA systems

CODE	OPEX	Units	OCGT	MEA	VPSA
O1	Natural gas price	M£/yr	1.45	0.00	0.00
O2	Electricity price	M£/yr	0.00	2.37	2.46
O3	Steam cost	£/yr	0.00	0.00	0.00
O4	Water cost	£/yr	65.0	625	0.00
O5	Utilities	M£/yr	1.45	2.37	2.46
O6	Solvent/adsorbent	M£/yr	0.00	0.206	0.196
O7	Variable operations and maintenance	M£/yr	1.45	2.58	2.65
O8	Labour	M£/yr	0.200	0.200	0.200
O9	Maintenance	M£/yr	0.202	0.382	0.391
O10	Insurance	M£/yr	0.101	0.191	0.195
O11	Overhead	M£/yr	0.0505	0.0956	0.0976
O12	Financing working capital	M£/yr	0.0151	0.0261	0.0267

O13	Fixed operations and maintenance	M£/yr	0.569	0.896	0.910
	VOM	**M£/yr**	**1.45**	**2.58**	**2.65**
	FOM	**M£/yr**	**0.569**	**0.896**	**0.910**

3.1. Levelised cost of electricity

The LCOE for the OCGT, OCGT+MEA, and OCGT+VPSA plants, is shown in Figure 10. Included in the graph is the cost without CO_2 conditioning, to highlight the effect the compression train has on the cost of power. The LCOE for the OCGT plant (172 £/MWh) is comparable to sources in the literature, LeighFisher [50] showed LCOE ranges between 155-371 £/MWh for a 100 MWe plant, and BEIS [26] showed the LCOE ranges between 161-383 £/MWh for a 100 MWe plant. Including PCC for OCGTs drastically increases the LCOE. For an OCGT with MEA CO_2 capture (including conditioning, transport, and storage), the LCOE is 508 £/MWh. For an OCGT with VPSA CO_2 capture (including conditioning, transport, and storage) the LCOE is 514 £/MWh. Excluding the cost associated with CO_2 conditioning reduces the LCOE for the MEA and VPSA cases to 400 and 405 £/MWh respectively. These scenarios do not include a carbon price as the effect of carbon price (CP) is shown in Table 7. Both capture technologies are comparable in terms of cost; however, the VPSA system has a higher capture rate and thus the cost of capturing the CO_2 is lower (see Table 7).

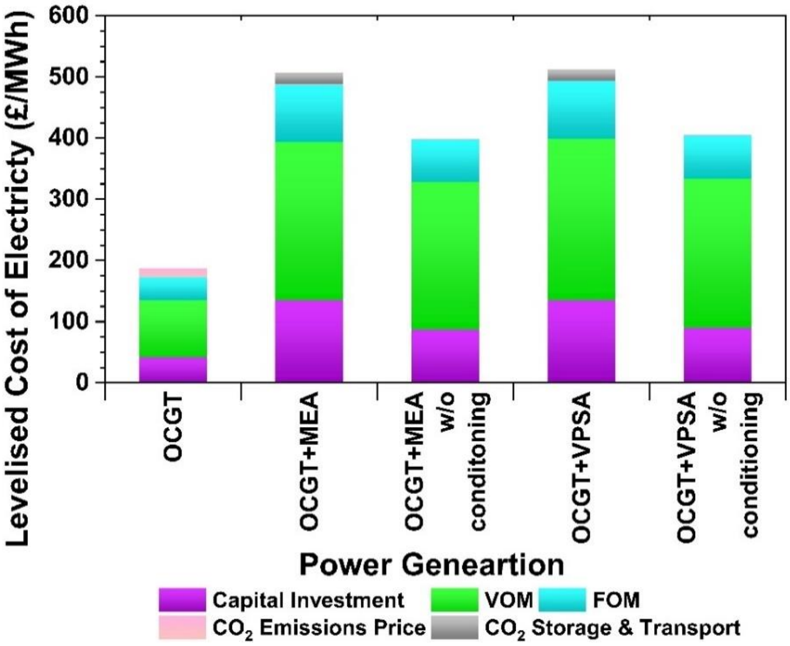

Figure 10: Levelised cost of electricity for the OCGT, OCGT+MEA, and OCGT+VPSA plants. Also included is the cost without CO_2 conditioning.

Table 7 highlights the key performance indicators (KPIs) for OCGT with and without carbon capture, without the costs associated with transportation and storage. Using VPSA to capture CO_2 results in slightly higher CAPEX and OPEX compared to the MEA case. Overall, the CCA (including CP) for OCGT+MEA is 448 £/tCO2 and for OCGT+VPSA it is 433 £/tCO_2. Using VPSA results in a lower cost of avoidance due to a higher capture rate achieved in the scaled process model. Excluding conditioning from the calculations (CCC rather than CCA), the OCGT+MEA case costs 316 £/tCO_2 and the OCGT+VPSA case cost 306 £/tCO_2. The energy penalty for including carbon capture is 12.4% for the MEA case and 12.9% for the VPSA (Table 4). Interestingly, the MEA case can use waste heat from the turbine to provide steam for solvent regeneration, potentially offsetting the energy penalty for this configuration;

however, including this analysis is beyond the scope of this project. Future work should investigate optimised process designs with heat integration, as this is a potential way to minimise the cost of CO_2 capture and make these types of generators more cost competitive.

Table 7: Key performance indicators for open-cycle gas turbines with and without CO_2 capture

KPI	OCGT	OCGT+MEA	OCGT +VPSA	Difference (%)
Net power output (Mwe)	10.40	9.11	9.06	-0.50
CO_2 capture rate (%)	-	92.5	97.1	4.96
CO_2 emitted (tCO_2/yr)	12400	981	363	-63.1
CO_2 captured (tCO_2/yr)	-	11400	12000	4.96
CAPEX (M£)	6.53	18.9	19.1	1.35
OPEX (M£/yr)	2.02	5.50	5.59	1.60
LCOE (£/MWh)	172	487	495	1.53
LCOE including CP (£/MWh)	188	508	514	1.35
CCA (£/tCO_2)	-	470	454	-3.35
CCA Including CP (£/tCO_2)	-	448	433	-3.51
CCC (£/tCO_2)	-	338	328	-2.86
CCC Including CP (£/tCO_2)	-	316	306	-3.05

3.2. Comparison to other energy generators

Figure 12 highlights the comparison between the CCA for the systems evaluated in this study (OCGT, OCGT+MEA, and OCGT+VPSA), compared to other power generation sources that include CCUS from BEIS [28]. The BEIS study investigated different forms of power generation: combined-cycle gas turbine (CCGT), integrated reforming combined cycle (IRCC), integrated gasification combined cycle (IGCC), supercritical pulverised coal (SCPC), and bioenergy with CCS (BECCS).

Within the BEIS study the plant availability or capacity factor was set at 100% (8760 hours), in this study the capacity factor is 17.12% (1500 hours). A lower capacity factor is disadvantageous as you cannot generate enough annual revenue to offset operating and maintenance costs. The CCA is much higher for the OCGT+PCC cases compared to the other power sources, except BECCS. Without the CP included, BECCS costs 617-661 £/tCO_2, whereas OCGT+PCC costs 448-470 £/tCO_2. With CP included, BECCS costs 524-572 £/tCO_2, whereas OCGT+PCC costs 433-454 £/tCO_2. The larger drop in CCA when including a CP for BECCS is due to the quantity of CO_2 captured and the variable CP used (21.6-223 £/tonne CO_2). The CCA for OCGT+PCC is comparable to BECCS sources, and both will be crucial in achieving net-zero emissions targets. The affect CP has on the LCOE and CCA is investigated in Section 3.3.

Danaci et al. [16] highlights the economies of scale for PCC and showed at smaller flue gas flowrates and low CO_2 feed concentrations, the cost of capture drastically increases. This has been further confirmed by the results presented and poses a real problem for future energy systems. The net power export range (356 -1,509 MWe) from the BEIS study is significantly higher than the 10 MWe power generator investigated in this study, highlighting the challenges with small plant size. As the move towards a net-zero power grid progresses, these small dispatchable generators that provide security of supply and system inertia will also require CO_2 capture; however, the cost to do so is higher than other power sources due to:

- **Economies of scale** – the power generation plant, capture plant and conditioning train suffer from their relatively small size**.**
- **Low-capacity factor** – as less CO_2 is captured due to less active annual operating hours, the overall cost per ton of CO_2 captured is much higher.

These small gas-fuelled dispatchable generators may therefore need government assistance to stay competitive in a future low/zero-carbon energy system, or they need to be removed from the capacity mix to ensure Net-Zero is achieved cost-effectively.

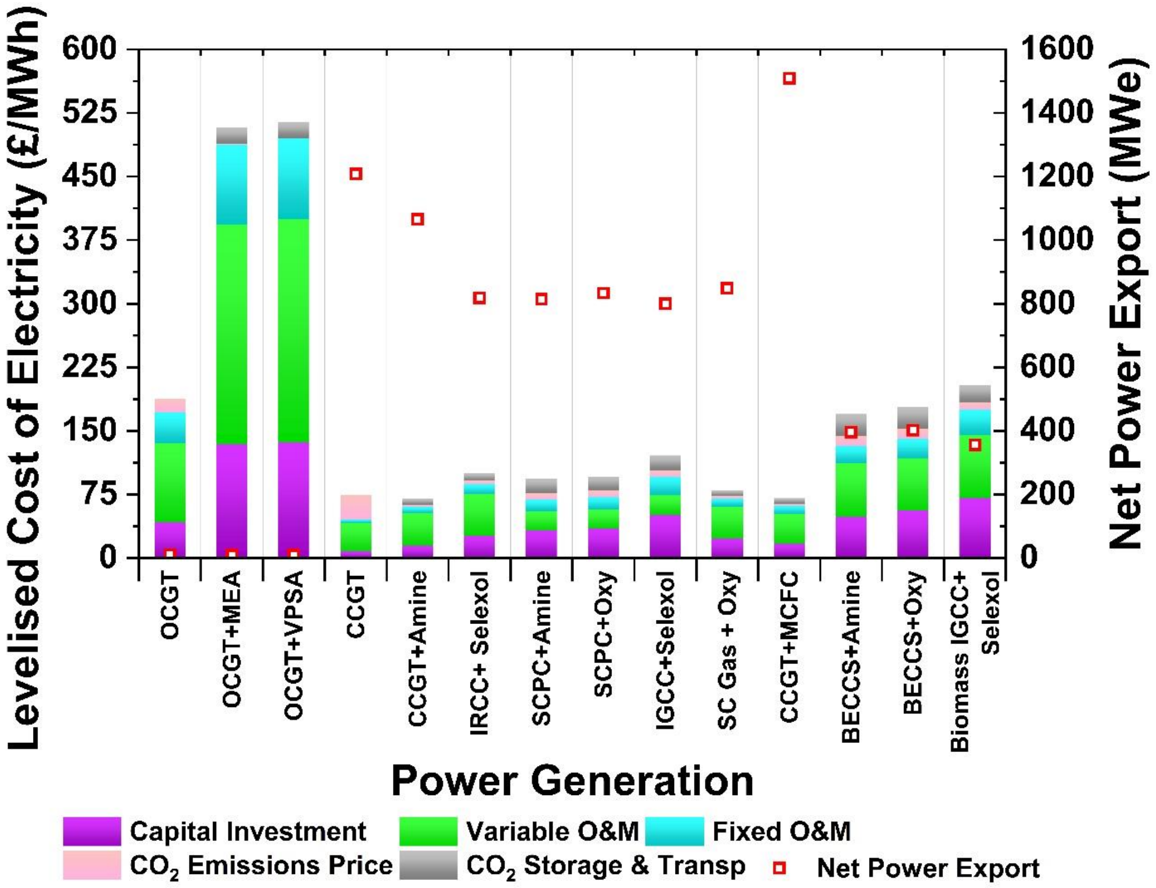

Figure 11: LCOE and net power export comparison between OCGT+PCC (this studies work) and other power generation sources that include CO_2 capture (BEIS [24])

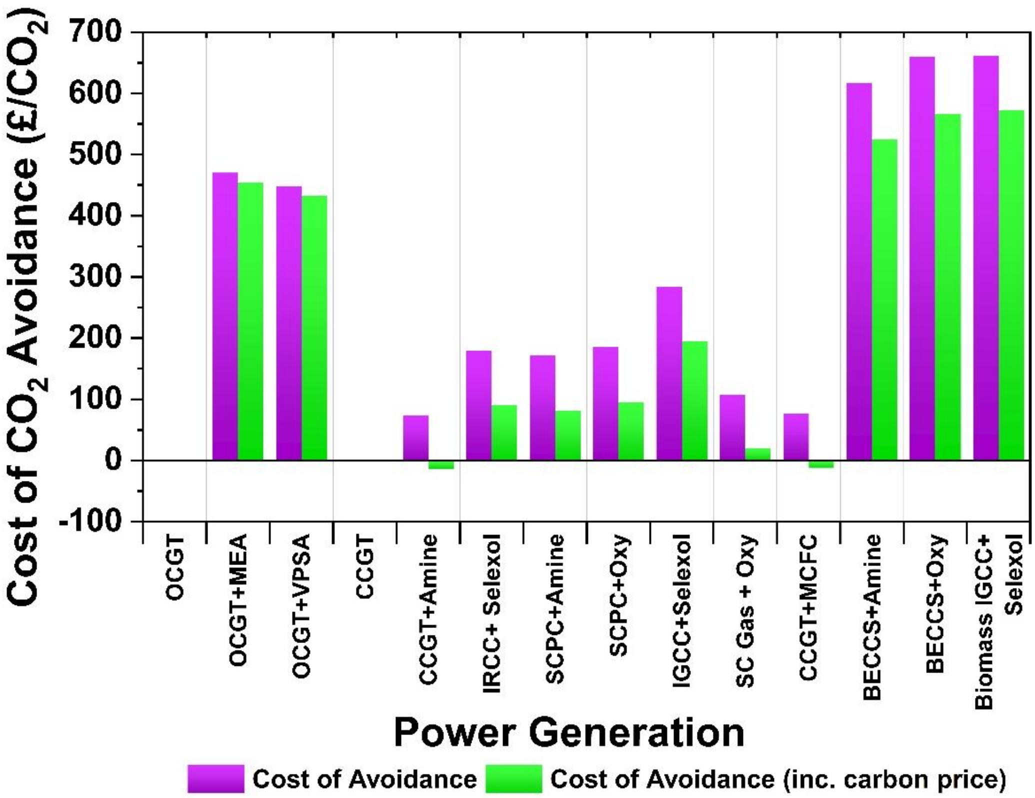

Figure 12: Cost of CO_2 avoidance comparison between OCGT+PCC (this studies work) and other power generation sources that include CO_2 capture (BEIS [24])

3.3. Sensitivity Analysis

As part of the economic assessment, a sensitivity analysis on different capacity factors is conducted. Figure 13 shows the LCOE for the OCGT, OCGT+MEA, and OCGT+VPSA systems at 250-8,000 total annual operating hours, i.e., at different capacity factors. Shockingly, there is a drastic increase in cost at <1,000 hours, as less power can be generated from the OCGT. From the BMRS data analysed in [17], OCGTs between 2016-2019 had an average annual operating time of 250 hours. This pushes the LCOE up to almost £1800/MWh, which is not competitive in any electricity market.

At 2000 annual operating hours, considered a peak capacity factor value [50, 26], the LCOE for an unabated OCGT is 153 £/MWh (169 £/MWh with CP). Including MEA or VPSA CO_2 capture increases the LCOE to 428 £/MWh (429 £/MWh with CP) or 434 £/MWh (435 £MWh with CP), respectively. At 8760 hours (100% capacity factor) the LCOE for an unabated OCGT is 108 £/MWh (124 £/MWh with CP). Including MEA or VPSA CO_2 capture increases the LCOE to 290 £/MWh (292 £/MWh with CP) or 290 £/MWh (297 £MWh with CP), respectively. At higher capacity factors, the cost of including CO_2 capture decreases. Interestingly, as the capacity factor increases more CO_2 is produced annually, therefore, it should become more costly due to the carbon price. However, the curves never cross, i.e., the carbon price is not high enough to counteract the cost of capture. Figure 14 shows the effect annual operating hours has on the CCA, where it can be seen to follow an identical profile as the LCOE and shows the rate at which the costs increase as the plant operates less. Small-scale OCGT with PCC has a high CCA even at maximum operating time. Therefore, future work should investigate economies of scale specifically for 1-100 MWe OCGTs, to identify the size at which these generators become comparable to other power generation sources.

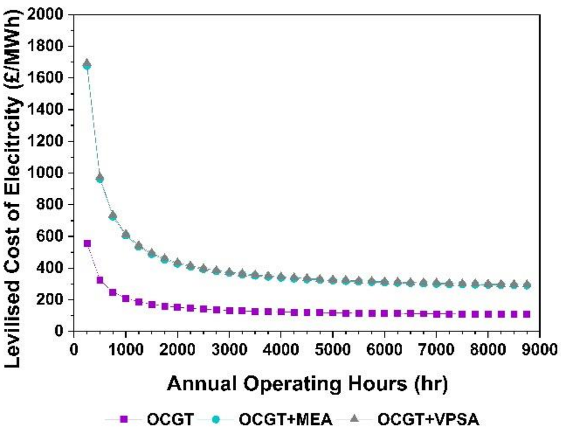

Figure 13: Levelised cost of electricity for OCGT, OCGT+MEA, OCGT+VPSA plants, at different total annual operating hours (capacity factor)

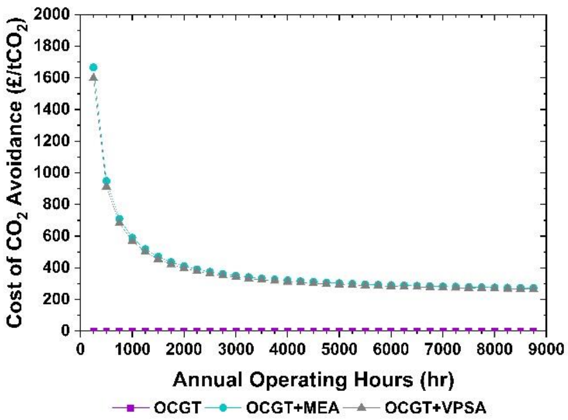

Figure 14: Cost of avoidance for OCGT, OCGT+MEA, OCGT+VPSA plants, at different total annual operating hours (capacity factor)

Contour plots showing the relationship between the LCOE, CP and capacity factor are shown in Figure 15, Figure 16, and Figure 17, for the OCGT, OCGT+MEA, and OCGT+VPSA plants, respectively. The LCOE range for the OCGT scenario is much lower than the OCGT+PCC scenarios; however, the OCGT plant is much more sensitive to carbon price (Figure 15). The OCGT+PCC technologies are mainly influenced by the total annual operating hours, hence the stacked colour flow. For each system, the highest LCOE range is <1000 annual operating hours. This is an issue for OCGTs as they usually operate within this region.

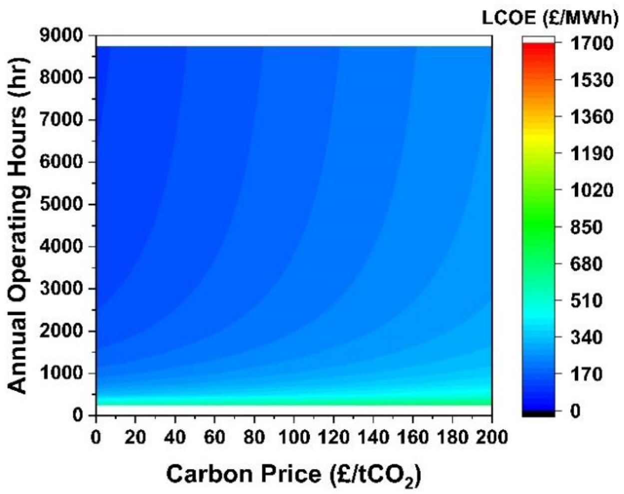

Figure 15: Contour plot showing the levelised cost of electricity at different carbon prices and annual operating hours for the OCGT scenario.

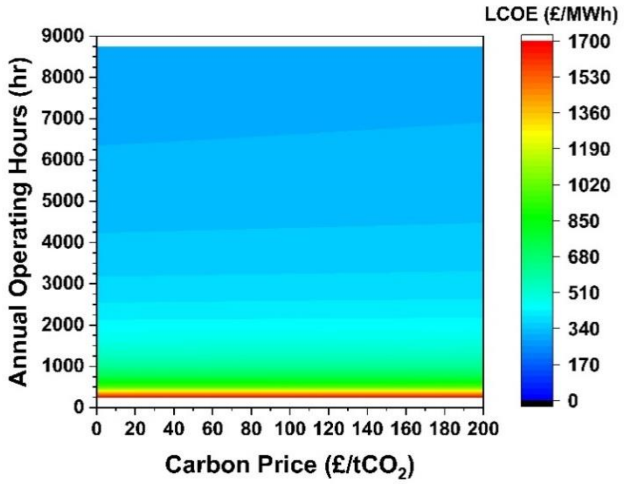

Figure 16: Contour plot showing the levelised cost of electricity at different carbon prices and annual operating hours for the OCGT+MEA scenario.

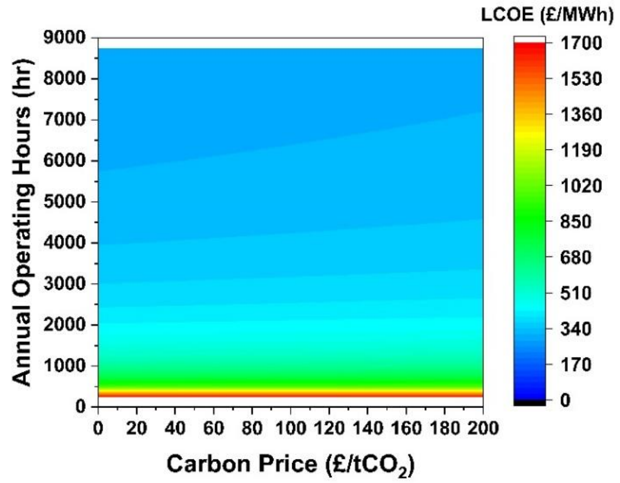

Figure 17: Contour plot showing the levelised cost of electricity at different carbon prices and annual operating hours for the OCGT+VPSA scenario.

Figure 18 and Figure 19 show the influence carbon price has on the LCOE for all three processes for different annual operating hours. For CO_2 capture to be worthwhile economically for small-scale OCGTs, the carbon price would need to be >470 £/tCO_2 at 1500 annual operating hours, and >276 £/tCO_2 at 8760 annual operating hours. This break-even price is also known as the cost of CO_2 avoidance or CCA. Figure 18 and Figure 19 also show the point at which VPSA becomes more economically favourable compared to MEA CO_2 capture. At 200 £/tCO_2 (Figure 18), the lines for MEA and VSPA cross, due to the higher capture rate exhibited in the scale VPSA process. In Figure 19, this point occurs at 150 £/tCO_2.

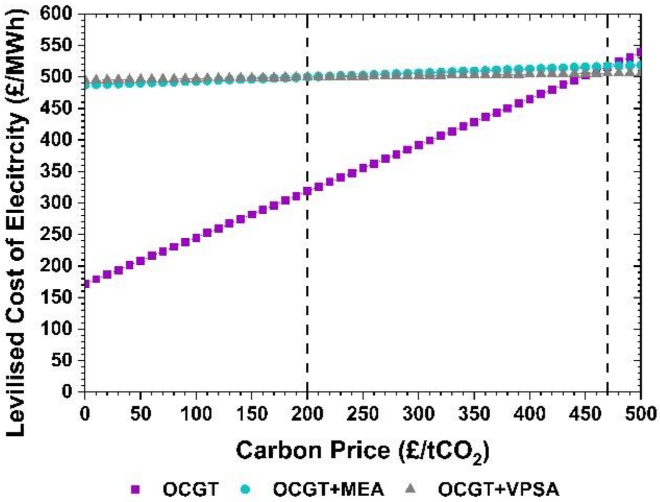

Figure 18: Levelised cost of electricity at different carbon prices for OCGT, OCGT+MEA, OCGT+VPSA plants. All scenarios are based on 1,500 annual operating hours.

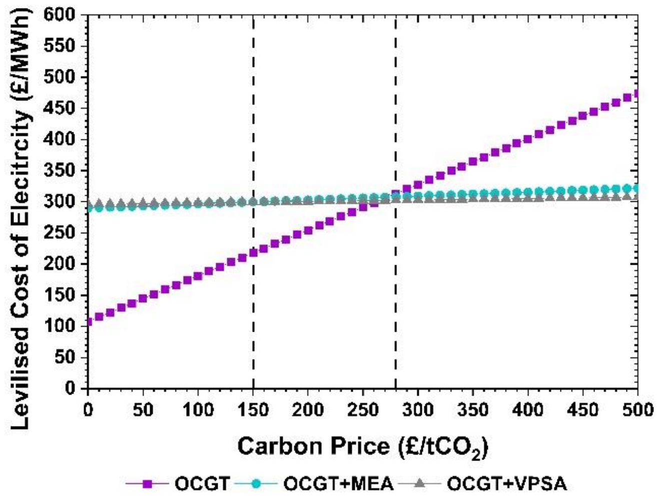

Figure 19: Levelised cost of electricity at different carbon prices for OCGT, OCGT+MEA, OCGT+VPSA plants. All scenarios are based on 8,760 annual operating hours.

The cost of capturing and compressing CO_2 from small-scale power sources is extremely high. If plants of this size were operated continuously (100% CF), the LCOE and CCA would still be higher than other low-carbon sources. Therefore, the compression demand must be shared with other neighbouring CO_2 emitters in cluster systems, or the CO_2 needs to be directly utilised on-site.

4. Conclusion

Herein, an economic model was used to highlight the cost of including MEA and VPSA CO_2 capture in an OCGT power plant. This paper compares the performance of these systems, to other low-carbon and dispatchable power generation sources. The LCOE for OCGT+PCC (506-514 £/MWh) is much higher than the sources investigated in BEIS [28] (70.7-204.3 £/MWh). This is due to the low CF for OCGT plants. A sensitivity analysis investigating the effect of different CFs showed an extreme increase in cost between 250-1000 annual operating hours. This is problematic as OCGTs typically operate in this window. A similar trend is observed for the CCA, reaching almost 1,700 £/tCO_2 at 250 annual operating hours

(CF=2.85%). Another element that influences the LCOE is the carbon price, which has more of an effect on the unabated power plant than it does on the MEA and VPSA cases. At 1,500 annual operating hours (typical of OCGTs) the carbon price would need to be >470 £/tCO_2 to break even. The results also showed that increasing the carbon price changes the economic capture option. At a CP of 200 £/tCO_2, VPSA becomes the cheaper option due to the high quantity of CO_2 captured. Overall, the two main factors affecting OCGT+PCC are the economies of scale and the capacity factor, as these plants are small in size and are only used for peak demand.

The results also show that the CCA is comparable to BECCS. Therefore, much like the subsidies provided to BECCS for negative emissions, government aid might also be required for these dispatchable generators to provide system security whilst also being low-carbon. Another key finding is that the conditioning costs are higher than the capture costs for both capture technologies. Thus, these small-scale systems, irrespective of the capture method, would benefit from sharing the compression requirements with neighbouring emitters or removing these requirements by focussing on utilisation. Investigating CO_2 utilisation for OCGT+PCC is beyond the scope of this project; however, the reader might find these sources helpful in understanding Carbon Dioxide Utilisation (CDU) [51, 52]. Future studies should investigate integrating dispatchable power generation with CO_2 capture and utilisation. In future energy systems, security of supply will be extremely important, and currently, this is provided by quick-response fossil sources. Unless energy storage can become significantly cheaper, these integrated systems require immediate attention.

5. Acknowledgements

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