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BECCS techno-economic analysis for solvent post-combustion capture using concentrated MEA and an advanced amine blend to compare with MCFC configurations

CCUS Innovation 2.0

Key Knowledge Deliverable 3.4

January 2024

Key Knowledge Deliverable Cover Sheet

This Key Knowledge Deliverable (KKD) has been produced by the Translational Energy Research Centre at the University of Sheffield as part of the Department for Energy Security and Net Zero £1bn Net Zero Innovation Portfolio (NZIP) - CCUS Innovation 2.0 programme. The document is reflective of the status of the project at the time of writing. The material presented could be subject to change as the project matures. These documents should not be considered a full representation of the final project.

UK BECCS-MCFC: Next Generation CCUS Technology for Net-Zero 2050

Baseline Test Work: Optimisation - Reporting Optimised solvent/plant configurations.



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BECCS techno-economic analysis for solvent post-combustion capture using concentrated MEA and an advanced amine blend to compare with MCFC configurations

The purpose of this report is to analyse overall costs and performance for solvent post-combustion capture using concentrated (35% w/w) MEA and an advanced amine blend (CESAR1 – a mixture of 13 %w/w piperazine (PZ) and 27% w/w AMP) in BECCS plants based on biomass-fired boilers using a simple integrated configuration and, by inclusion of the value of the electricity and hydrogen output lost or gained, configurations that match molten carbonate fuel cell BECCS configurations in consuming natural gas to produce additional electricity or hydrogen.

The background is a 'decarbonised', i.e. net zero or close to net zero, UK electric power system, as expected to be implemented by 2035.

It builds on two previous reports:

- WP3.1 Optimised solvent plant configurations for comparison with BECCS MCFC options*

- WP3.2 & 3.3 Performance data and solvent degradation and management for concentrated MEA and an advanced amine blend*

The report also makes some initial estimates of molten carbonate fuel cell CO₂ capture costs for comparison based on published data and additional approximations, but these are intended mainly to illustrate factors that may be important in the detailed techno-economic analysis for the MCFC that will be undertaken later in this project.

Glossary

AMP	Aminomethyl Propanol
bara	Bars Absolute (absolute pressure in bars, i.e. units of 10^5 Pa)
barg	Bars gauge, pressure in relation to atmospheric pressure
BAT	Best Available Technology
BD3	Boundary Dam power plant, Unit 3; the first power plant fitted with PCC
BECCS	Biomass Energy with Carbon Capture and Storage
BREF LCP	The BAT Reference Document (BREF) for Large Combustion Plants (BREF LCP, 2017)
CCC	Climate Change Committee (www.theccc.org.uk)
CCGT	Combined Cycle Gas Turbine power plant
CCS	Carbon (dioxide) Capture and Storage
CCU	Carbon (dioxide) Capture and Utilisation, not involving permanent storage of the CO_2
CCUS	Carbon (dioxide) Capture, Utilisation and Storage (overwhelmingly EOR at present)
CDR	Carbon Dioxide Removal from the air
CFB	Circulating Fluidised Bed boiler/steam power plant
CHP	Combined Heat and Power plant
CO_2	Carbon dioxide
COPx	The Coefficient Of Performance for (steam) extraction; ratio of heat supplied to a PCC plant by steam extracted from a steam cycle to the reduction in work (electricity) output from that steam cycle
DCC	Direct Contact Cooler; brings the flue gas into contact with water upstream of the absorber, possibly with added caustic to neutralise acid gases
DESNZ	Department for Energy Security & Net Zero, see https://www.gov.uk/government/organisations/department-for-energy-security-and-net-zero
DPA	Dispatchable Power Agreement, see https://www.gov.uk/government/publications/carbon-capture-usage-and-storage-ccus-business-models
EAL	Environmental Assessment Level
EfW	Energy from Waste
ELV	Emission Limit Value
EOP	Electricity Output Penalty
ESP	Electrostatic Precipitator
FCC	Fluid Catalytic Cracker
FGD	Flue Gas Desulphurisation plant
FWH	Feed Water Heater (in a steam boiler)

GT	Gas Turbine
HHV	Higher Heating Value (also known as gross calorific value)
HP	High Pressure, the highest pressure cylinder in a steam turbine
HRSG	Heat Recovery Steam Generator (sometimes pronounced “hersig”)
HSS	Heat Stable Salts
IP	Intermediate Pressure, the intermediate pressure cylinder in a steam turbine
IX	Ion exchange reclaimer unit
LC MS QQQ	Liquid Chromatography with triple-Quadrapole Mass Spectrometry
LHV	Lower Heating Value (also known as net calorific value)
LP	Low Pressure, the lowest pressure cylinder in a steam turbine
MEA	Monoethanolamine
MHI	Mitsubishi Heavy Industries
MSG	Minimum Stable Generation
MSW	Municipal Solid Waste
N/A	Not Applicable
NCCC	National Carbon Capture Center https://www.nationalcarboncapturecenter.com/
NETL	National Energy Technology Laboratory https://www.netl.doe.gov/
NGCC	Natural Gas Combined Cycle
NH ₃	Ammonia
NO _x	Oxides of Nitrogen
NPC	National Petroleum Council https://www.npc.org/
O ₂	Oxygen
OEM	Original Equipment Manufacturer
Pa	Pascal, unit of pressure, 1N/m ²
PAC	Powdered Activated Carbon
PCC	Post-combustion (CO ₂) capture
ppm	parts per million
ppmv, ppbv	parts per million by volume; parts per billion by volume
PTR-TOF-MS	Proton-transfer-reaction time-of-flight mass-spectrometer. Used to measure VOCs. Similarly, QMS = quadrupole-mass-spectrometer
PZ	Piperazine
RAMO	Reliability, Availability, Maintainability, Operability
RFCC	Residual Fluid Catalytic Cracker
RH	Reheat(er) (in a steam boiler)
SCR	Selective Catalytic Reduction (of NO _x)
SO ₂	Sulphur dioxide
SO ₃	Sulphur trioxide (with water, forms sulphuric acid)

SOx	Oxides of Sulphur (unspecified mix of SO ₂ and SO ₃)
ST	Steam Turbine
STG	Steam Turbine Generator
T&S	(CO ₂) Transport and Storage
TCM	Technology Centre Mongstad https://tcmda.com/
TEA	Techno-Economic Analysis
TERC	Translational Energy Research Centre, University of Sheffield https://terc.ac.uk/
TONO	Total nitrosamines
tpd	tonnes per day
TPY	Tonnes Per Year
TRU	Thermal Reclaimer Unit
VLE	Vapour Liquid Equilibrium
VRE	Variable Renewable Electricity
VOC	Volatile Organic Compounds
WESP	Wet ElectroStatic Precipitator
XFHE	The cross-Flow Heat Exchanger, transferring heat from the hot lean solvent leaving the stripper to the cooler rich solvent coming from the absorber

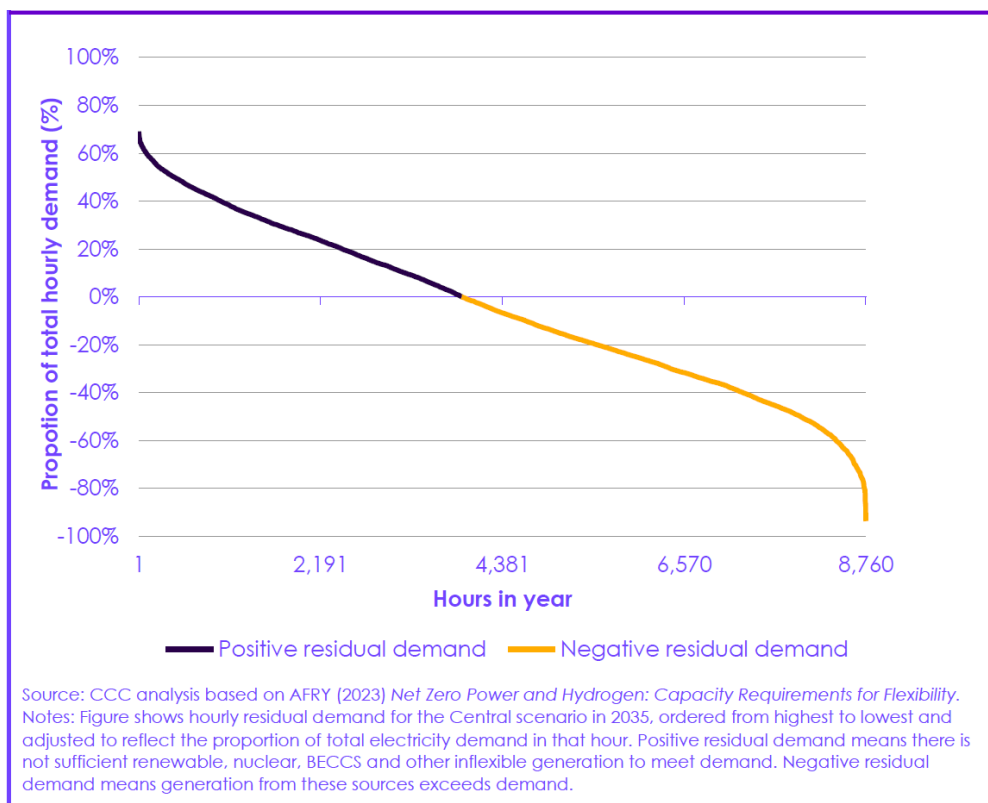
Future UK energy sector scenarios and consequences for TEA inputs

Future UK electricity sector scenarios

Scenarios for ‘decarbonised’, i.e. net zero or close to net zero, UK electric power system, as expected to be implemented by 2035, were recently published by the Climate Change Committee¹. These will be used as the background for TEA assessments of solvent BECCS options and a commentary on key TEA issues for MCFC BECCS options.

Values for exported electricity are a key factor determined by the wider electricity sector. It is important to note that the exact details of the electricity systems in the scenarios are not important in the relative assessment, which uses them only as an illustration of factors in the performance of BECCS systems that will be important. The inevitable uncertainty with respect to future conditions, which in any case will naturally be changing over time as the electricity system develops, is accommodated by the use of sensitivity ranges for key parameters.

The key characteristic of the future UK electricity sector, as shown in the figure below, is the existence of significant periods (in excess of 50% of the time) when inflexible generation output, predominantly renewables and nuclear, exceeds consumer demand.



Committee on Climate Change estimates for residual electricity demand in 2035

¹ <https://www.theccc.org.uk/publication/delivering-a-reliable-decarbonised-power-system/>

It is envisaged by the CCC that this excess electricity will be exported or used for electrolytic hydrogen production, but the market for such uses and the prices that will be paid in that market are obviously uncertain. So possible assumptions for the value of electricity during this period of oversupply of inflexible electricity could vary from zero up to the cost of production, tentatively estimated at around £50/MWh based on recent renewable electricity auctions. If the value exceeded the cost of production then it could be expected that, over time, more renewable capacity would be built and the cost would revert to that value. Obviously, though, if the electricity value is higher than the average cost for at least some of the time that the variable renewable energy generation assets are operating, i.e. when VRE supply does not exceed demand, then they can be lower than average cost at other times, i.e. when VRE supply exceeds demand, so this upper estimate may be generous.

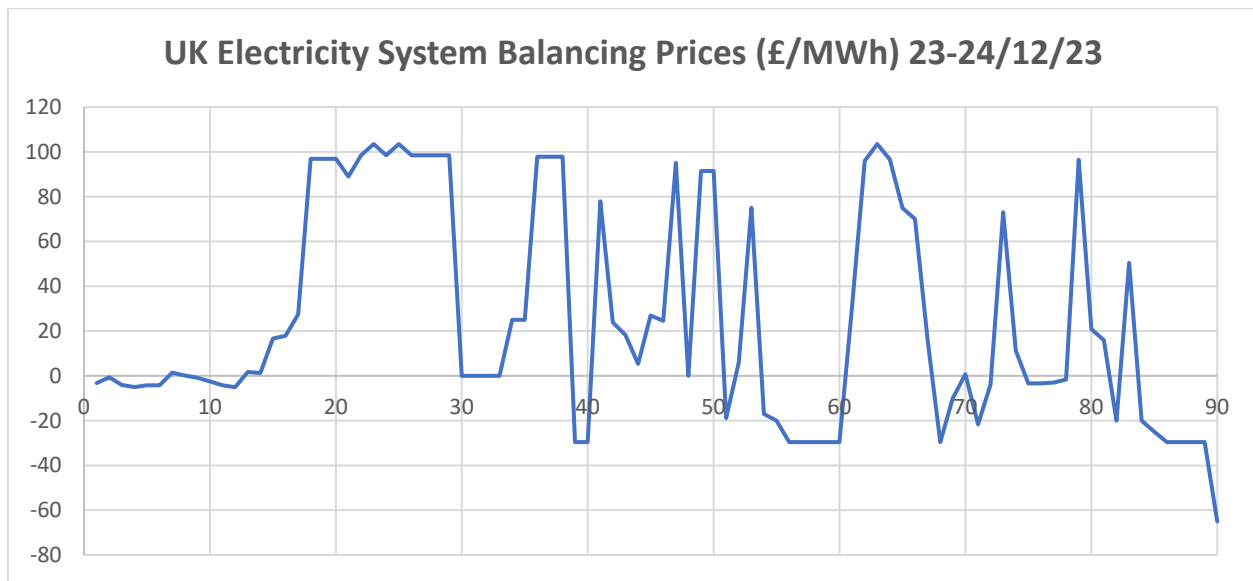
For other periods, when consumer demand is in excess of the inflexible electricity supply at the time, dispatchable generation capacity will have to be used up to the level required to meet the demand. This could include supplying power from batteries or other electricity storage, although these will have a finite capacity, or, in order of cost for load factors above around 30%, the following fuelled power generation options:

- low-emission generation from CCGT+PCC plants,
- hydrogen-fired CCGT,
- hydrogen-fired OCGT or engines or
- unabated generation assets with their emissions recaptured from the atmosphere using CDR.

Given that a BECCS plant will be operating all of the time that dispatchable electricity is required then a CCGT+PCC plant would be a reasonable benchmark for the value of electricity exported during these periods. Again, if prices for long-duration controllable generation were expected to exceed this benchmark then additional capacity would be constructed.

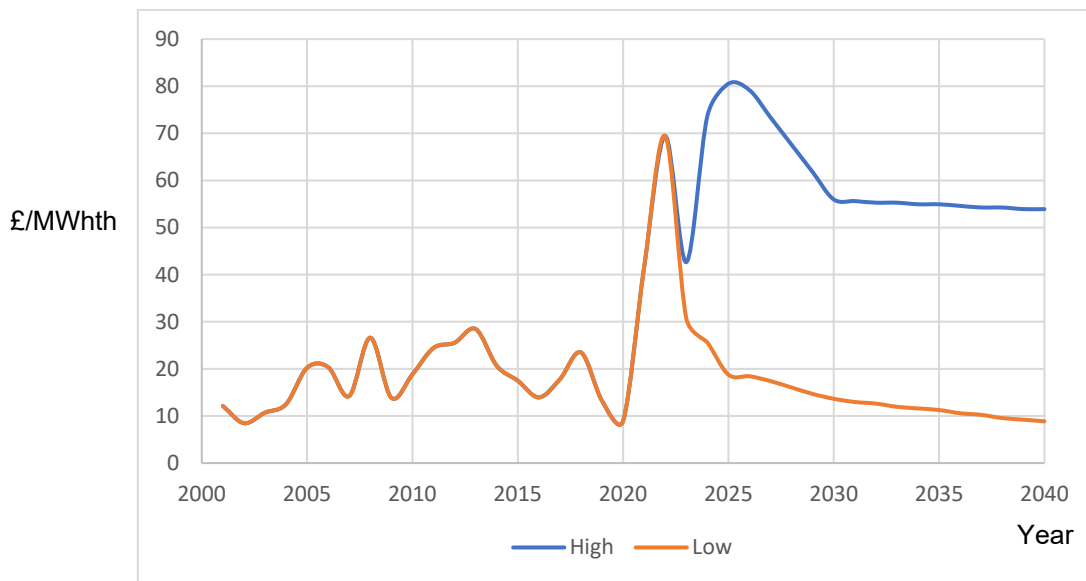
A prediction of future electricity values as a function of time is clearly beyond the scope of this study, but by way of illustration of possible trends see the variation in UK System Prices for 90 half hour periods starting on 23 December, 2023 below²:

² <https://www.bmreports.com/bmrs/?q=balancing/systemsellbuyprices>



Future UK natural gas price ranges

Future UK natural gas prices for power generation will have a significant effect on TEA outcomes. Future high and low fossil fuel price scenario predictions from the DESNZ 'Energy and emissions projections: 2022 to 2040'³ for natural gas prices in £/MWh are shown below. For sensitivity analyses future natural gas prices of £10/MWh, £35/MWh and £55/MWh HHV will be considered.



Natural gas price predictions (in 2022 prices, £/MWhth HHV) from the high and low fossil fuel price scenarios in DESNZ 'Energy and emissions projections: 2022 to 2040'

³ <https://www.gov.uk/government/collections/energy-and-emissions-projections>

Other key TEA inputs

Recent cost estimates for CCGT+PCC plant were provided in studies for BEIS by Wood⁴ and AECOM⁵ and these will be used as the basis for non-fuel cost estimates for this assessment.

Other key variables are CO₂ transport and storage costs, and valuations for produced hydrogen. All of these are also uncertain and will vary with time and so will also be dealt with using sensitivity ranges.

It can be assumed that hydrogen values are set by blue hydrogen production from natural gas with CCS, as the marginal production route by which extra output can be increased as required (i.e. not limited by available renewable electricity, especially available renewable electricity at times of excess supply). The blue hydrogen cost is itself obviously a strong function of the natural gas price, which will be included as a range of values in the TEA. Capital and other costs for blue hydrogen plants will be taken from a recent study by BEIS 'Hydrogen Production Costs 2021'⁶.

Power plant and amine post-combustion capture plant capital and non-fuel operating costs

Given the limited project resources applied to it, the TEA study needs to use available public domain material where feasible and will therefore be based on the analysis undertaken by AECOM for DESNZ⁵ on an EfW power plant. Since the characteristics of the biomass power plant itself are not required for the analysis if baseload operation is assumed then this is not a serious limitation. The size of the plant (~1000 tpd CO₂ and ~30MWe output without CCS) are plausible for a purpose-built biomass power plant (i.e. not a converted pulverised coal plant). See the table below for all UK 'biofuel' power plants, with data taken from Digest of UK Energy Statistics (DUKES): electricity, 2023⁷.

Site Name	CHP	Primary Fuel	Installed Capacity (MW)	Year	Region
Blackburn Meadows	Yes	Biomass	34	2015	Yorkshire and Humber
Steven's Croft	Yes	Biomass	46	2007	Scotland
EPR Ely Ltd	No	Biomass	40	2001	Eastern
EPR Eye Ltd	No	Biomass	14	1992	Eastern
EPR Glanford Ltd	No	Biomass	14	1993	Eastern

⁴https://assets.publishing.service.gov.uk/media/5e41657940f0b6090defbc83/BEIS_Final_Benchmarks_Report_R ev_4A.pdf

⁵<https://www.gov.uk/government/publications/review-of-next-generation-carbon-capture-technology-for-industrial-waste-and-power-sectors>

⁶<https://www.gov.uk/government/publications/hydrogen-production-costs-2021>

⁷<https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes>

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EPR Scotland Ltd	No	Biomass	13	2000	Scotland
EPR Thetford Ltd	No	Biomass	42	1998	Eastern
Lynemouth Power Ltd	No	Biomass	420	2018	North East
Drax Biomass Units	No	Biomass	2640	2013	Yorkshire and Humber
Markinch	Yes	Biomass	65	2014	Scotland
Wilton 10 Biomass	Yes	Biomass	33	2007	North East
Slough Heat & Power	Yes	Biomass	20	2014	South East
FM1	No	MSW	79	2015	Yorkshire and Humber
FM2	No	MSW	79	2019	Yorkshire and Humber
Londonwaste Ltd	No	MSW	58	1970	London
Riverside - EfW	No	MSW	80	2011	London
Wilton 11	No	MSW	49	2016	North East
SELCHP	Yes	MSW	35	1994	London
Runcorn EfW	No	MSW	91	2014	North West

Relevant details for the amine PCC plant are in Tables 28-30 from the AECOM report and reported data for a MCFC application in Tables 58-60, included as Annex 1 for the convenience of readers. Key data is aggregated and summarised below, with additional estimated TEA input data as required.

Item	Units	Amine PCC	MCFC (for illustration)
Flue gas flow in	tph	237	237
CO ₂ content	%mol	12%	12%
Solvent		35% w/w MEA	
CO ₂ capture rate	% of CO ₂ in flue gas	95%	96% (& 100% of MCFC fuel CO ₂)
CO ₂ flow	tph / tpd	42 / 1000	53 / 1275 total – 42 from biomass
Natural gas supply	tph		5
Heat supply	MWth	42	
	GJ/tCO ₂	3.6*	
Loss in electricity output per unit of heat supplied ⁸	MW/MWth	0.25	

⁸ <https://ukccsrc.ac.uk/best-available-technology-bat-information-for-ccs/> ; <https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat>

BECCS techno-economic analysis for solvent post-combustion capture using concentrated MEA and an advanced amine blend to compare with MCFC configurations

Electricity supply	MWe	7	
Net extra electricity exported from capture unit	MWe		27
Grand total CAPEX	£M	96.8	122.3
Fixed OPEX	£M/yr at baseload	4.7	5.8
Variable OPEX (ex fuel/heat/power costs)	£M/yr at baseload	2.3	1.7
% of regeneration energy penalty shifted from high to low cost periods using solvent storage		0% – 50%	
Natural gas price	£/MWhth	10, 35, 55	
% of time inflexible electricity supply > demand		0% (ideal example only); 50% and 70% actual	
Average electricity price when inflexible electricity supply > demand	£/MWh	0 – 50, capped at marginal operating cost of CCGT+PCC if lower	
CO ₂ transport and storage cost (assumed variable)	£/tCO ₂	10 - 50	
Project economic lifetime	Years	10, 15	
Overall return on investment (ROI)		5%, 10%, 15%	

* Regeneration energy based on the review in Deliverable D3.2/3.3

CCGT+PCC data for estimating consistent electricity price when demand is greater than inflexible electricity supply is summarised below:

Item	Units	Value
Capital cost element	£/MWh baseload	20
Fixed operating costs	£/MWh baseload	7
Natural gas CO ₂ emissions*	tCO ₂ /MWhth HHV	0.185
Thermal efficiency	%HHV	50%
Capture rate	% of added CO ₂	95, 100
CO ₂ emission cost	£/tCO ₂	150
CO ₂ transport and storage costs	£/tCO ₂	10-50

* Associated methane and other GHG emissions are not included in this analysis

Shifting regeneration and compression energy penalty from high to low cost periods using solvent storage

The use of lean and rich solvent storage to shift the amine capture plant electricity output penalty for steam extraction and CO₂ compression from periods of high cost electricity to periods of low cost electricity while the main power plant continues to operate at base load has

been well-explored in the literature, e.g.⁹. The amount of shifting that can be done will depend on the plant-specific factors such as the amount of storage provided (i.e. hours of operation), the maximum rate at which solvent can be regenerated, the ability of the CO₂ transport and storage system to take extra CO₂ as well as on the timings of high/low cost electricity periods. An examination of the exact scope for this shifting is beyond the scope of this report but a sensitivity analysis over the range 0-50% of the high cost period will be used to estimate its potential value.

An interesting feature of such time shifting is that the CO₂ sent to the transport and storage system is inherently out of phase with CO₂ from CCGT+PCC generation capacity. This means that, on shared systems, T&S capacity is almost certainly going to be available and also, if the plants are adjacent, possibly there will be temporarily-unused stripper capacity on the CCGT+PCC plant that could be employed. This would also have the advantage of keeping the CCGT+PCC stripper ready to use when gas-fired power was again required.

⁹ Chalmers, H., Gibbins, J. and Leach, M. (2012) Valuing power plant flexibility with CCS: the case of post-combustion capture retrofits, *Mitigation and Adaptation Strategies for Global Change*, Vol. 17. <https://doi.org/10.1007/s11027-011-9327-5>

Costs of capture as a function of assumed market conditions and plant design for electricity-only applications

Overview

A simplified cost of capture for the biomass CO₂ is estimated using an Excel spreadsheet, printed in Annex 3.

The following scenarios are used to give an insight into how market conditions might affect amine PCC capture costs and the relative costs for an MCFC installation using published data. It is important to note that the main purpose of this exercise is the relative economic performance of the two capture options using the same inputs; absolute values for future projects are not being predicted.

The MCFC costs and performance will be modified in light of the findings of this study before the final TEA analyses are undertaken, but it is instructive at this stage, to help shape future work, to consider key MCFC characteristics and market conditions that influence relative costs.

Market conditions:

- Central gas price scenario
- Low gas price
- High gas price
- Increased renewables
- High CAPEX charges
- Low CAPEX charges

PCC plant design:

- Lower-energy solvent with higher variable costs
- Solvent storage to shift energy penalty timing (with assumed 10% capital cost increase, also sensitivity for break-even cost increase)

MCFC plant design:

- Electricity output only
- Electricity and hydrogen output

A summary of the results are shown in the table and figure overleaf, with a further breakdown in the following figures and a printout of the spreadsheet in Annex 3.

Key features of the calculations are:

- Costs are calculated for an hour's operation of the plant, with 8000 operating hours per year assumed
- All CAPEX costs are based on the assumed total final cost of the plant at the start of operation
- Full availability of the plant for its economic lifetime is assumed, the same economic lifetime and ROI is assumed for PCC and MCFC
- No taxes or inflation are included (and approximately 2021 capital costs)
- The natural gas, CO₂ T&S and CO₂ emission costs are common to all elements of the calculations

BECCS techno-economic analysis for solvent post-combustion capture using concentrated MEA and an advanced amine blend to compare with MCFC configurations

- The value of lost electricity output (PCC) or additional electricity output (MCFC) is assessed as:
 - the full cost of electricity generated from a CCGT+PCC plant when excess renewable power is not available
 - the lower of a specified value or the marginal operating cost of a CCGT+PCC plant when renewable generation is in excess
- For the PCC plant, it is assumed that a specified fraction of the electricity output penalty can be shifted from the period when excess renewables are not available to the period when they are, using solvent storage, to take advantage of the lower electricity prices
- Reduced solvent regeneration energy requirements can be specified, with no change in CAPEX or fixed OPEX but a possible change in variable OPEX (to allow for increased solvent costs)
- Hydrogen value is based on approximate mean production costs at the low/medium/high natural gas price levels used in this analysis plus data specified in a previous study for BEIS on hydrogen production costs (see Annex 2)

Results and discussion for PCC system

Calculated relative costs for capture and storage of CO₂ from a biomass plant using amine PCC and an illustrative MCFC system described in a previous study for BEIS¹⁰ are shown in the table and figure below and in more detail in the figures in the following pages. Note that this does not include the common cost – if any – for all options of generating a biomass power plant flue gas stream, just the cost of capture and storage of that CO₂, so it is not the cost of carbon dioxide removal (CDR) using BECCS.

Relative capture and storage costs in £/tCO₂ from an example biomass plant (see Annex 3 for details)

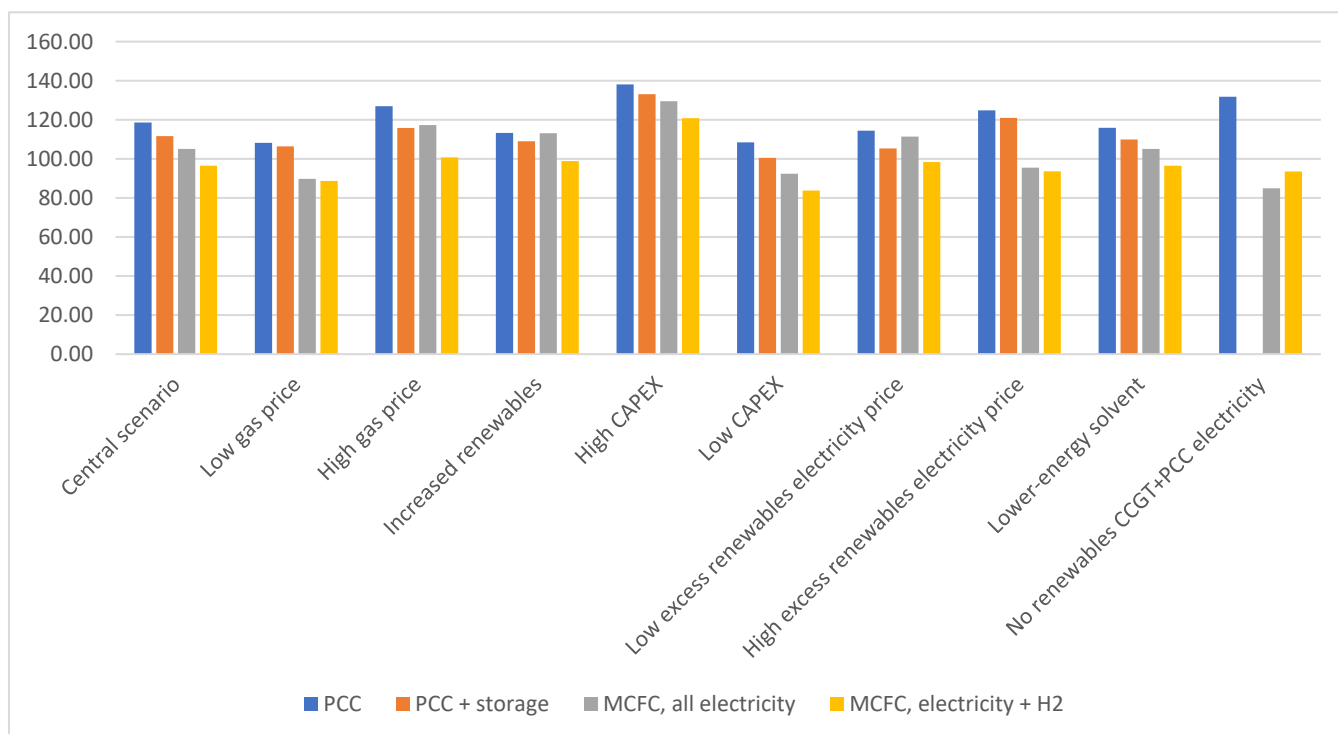
Selected Central Scenario Parameters	Units	Values
Excess renewables time	% of year	50%
Excess renewables electricity price	£/MWh	20
Amine specific reboiler duty reduction	% of normal SRD	100%
CCGT+PCC added CO ₂ capture rate		95%
Natural gas price	£/MWhth HHV	35
CO ₂ transport and storage cost	£/tCO ₂	30
CO ₂ emission cost	£/tCO ₂	150
Project economic life	Years	15
Return on investment (ROI - annual return on outstanding capital)		10%

Capture system	Central scenario	Low gas price	High gas price	Increased renewables	High CAPEX	Low CAPEX	Low excess renewables electricity price	High excess renewables electricity price	Lower-energy solvent	No renewables CCGT+PCC electricity
Main change	-	£10/MWh	£55/MWh	Excess time 70%	15% ROI	5% ROI	Zero	£50/MWh	-15%	-
PCC	118.57	108.15	126.90	113.29	138.10	108.45	114.40	124.82	115.88	131.76
PCC + storage	111.59	106.39	115.76	108.96	133.07	100.46	105.34	120.97	109.88	
MCFC – all electricity	105.03	89.71	117.28	113.08	129.44	92.37	111.39	95.49	105.03	84.89

¹⁰ <https://www.gov.uk/government/publications/hydrogen-production-costs-2021>

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MCFC – elec. + H2	96.42	88.67	100.74	98.83	120.83	83.76	98.32	93.55	96.42	93.49
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The trends in the calculated results show amine PCC capture costs for CCS increasing with increasing natural gas price, due to the higher value of the lost electricity, also increasing with capital servicing costs. Similarly, the overall CCS cost is also increased by an increase in the assumed cost of electricity when renewable generation is in excess of requirements.

The use of solvent storage to shift the electricity output penalty can reduce biomass CCS costs by up to nearly 10%, even if a 10% increase in CAPEX is assumed. The break-even increase in CAPEX would be about 25% (see Annex 3). A 15% reduction in the energy of regeneration (the maximum reduction for CESAR1 vs MEA reported in Deliverable 3.2/3.3) gave approximately 3% reduction in CCS costs. It is evident that, if lower-energy solvent costs are higher (a factor of nearly 4 higher is reported for CESAR1 vs MEA¹¹), then the cost of the extra inventory for solvent storage would be increased. In addition, a sensitivity analysis shown in Annex 3 also suggests that if solvent make-up and other solvent management costs are over 40% higher without solvent storage, or over 30% higher with solvent storage, then this will offset the value of the lower energy requirement.

¹¹ Weir, H., Sanchez-Fernandez, E., Charalambous, C., Ros, J., Garcia Moretz-Sohn Monteiro, J., Skylogianni, E., Wiechers, G9o., Moser, P., van der Spek, M., Garcia, S. (2023) *Impact of high capture rates and solvent and emission management strategies on the costs of full-scale post-combustion CO2 capture plants using long-term pilot plant data*, International Journal of Greenhouse Gas Control, Volume 126. <https://doi.org/10.1016/j.ijggc.2023.103914>,

Comparison using published MCFC data for electricity-only scenarios and possible areas of interest

Illustrative comparisons based on published MCFC data suggest that relative biomass CO₂ capture and storage costs, when the MCFC is producing only electricity, may be quite close to those for amine PCC in realistic electricity systems with predicted 2035 renewable penetration (e.g. excess renewable generation for ~ 50% of the time) and hence periods of time when electricity prices are well below those for gas-fired generation with CCS. Only if the now-unrealistic assumption was made that electricity prices were always set by CCGT+PCC, or if higher-than-expected electricity prices occurred when renewable electricity exceeded demand, would an MCFC electricity-only system be likely to show a large advantage.

Obviously the relative capital costs for the two systems are a key factor. As the breakdown below shows, capital costs are a major element, particularly for the MCFC system. CO₂ transport and storage costs may also be a significant part of the overall costs, particularly for the MCFC due to the extra CO₂ from the natural gas feed. Energy costs for the PCC system are always positive but, except for the 'no renewables' case where solvent storage cannot be used to shift some of these costs to less expensive times, they are less than CAPEX or T&S. Net energy costs (gas purchase less electricity sales) are generally close to breaking even for the MCFC, except that low gas prices or high electricity prices can give a negative net cost to be offset against other, positive, costs. This favourable energy result for the MCFC does depend, however, on the electricity output actually achieved and is a difference between relatively large numbers so quite sensitive to changes in performance.

Comparison using illustrative MCFC data for electricity plus hydrogen scenarios and possible areas of interest

The TEA for the case where the electricity output from the MCFC is decreased and there is a corresponding increase in hydrogen output relies on data for the MCFC fuel input and electricity and hydrogen production that appears not to be readily available in the public domain. Since it is being undertaken purely for illustrative purposes at this stage an arbitrary adjustment to the electricity-only case was therefore used, incorporating the following assumptions:

- The fraction of electricity output 'shifted' to hydrogen production is 70%
- 1.4 MWh HHV of hydrogen are produced for every MWh of electricity output lost

In addition, based on the analysis for hydrogen production costs as a function of natural gas prices presented in Annex 2, the following illustrative values for hydrogen are assumed:

- Low natural gas price £10/MWh HHV – hydrogen value £35/MWh HHV
- Medium natural gas price £35/MWh HHV - hydrogen value £65.00/MWh HHV
- High natural gas price £50/MWh HHV - hydrogen value £92.00/MWh HHV

The spreadsheet calculations for cases with MCFC electricity plus hydrogen production are shown in Annex 3 and the results plotted in the figure on the following pages. Largely because it is assumed that the hydrogen value doesn't change with time and is set by the cost of

production from natural gas, the costs of biomass CO₂ capture and storage are lower than for the electricity-only case for every scenario except the (unrealistic) no-renewables case where electricity value is determined by CCGT+PCC at all times. If, however, hydrogen production was in excess of demand at certain times, perhaps in the summer when demand was reduced, electrolytic hydrogen production from solar power was high, and available hydrogen storage was full, then constant hydrogen production from natural gas might not be such an advantage.

Obviously the actual MCFC hydrogen/electricity performance and capital costs are also important for absolute biomass CO₂ capture costs with the MCFC; it is emphasised again that these are purely illustrative estimates.

Overall Conclusions

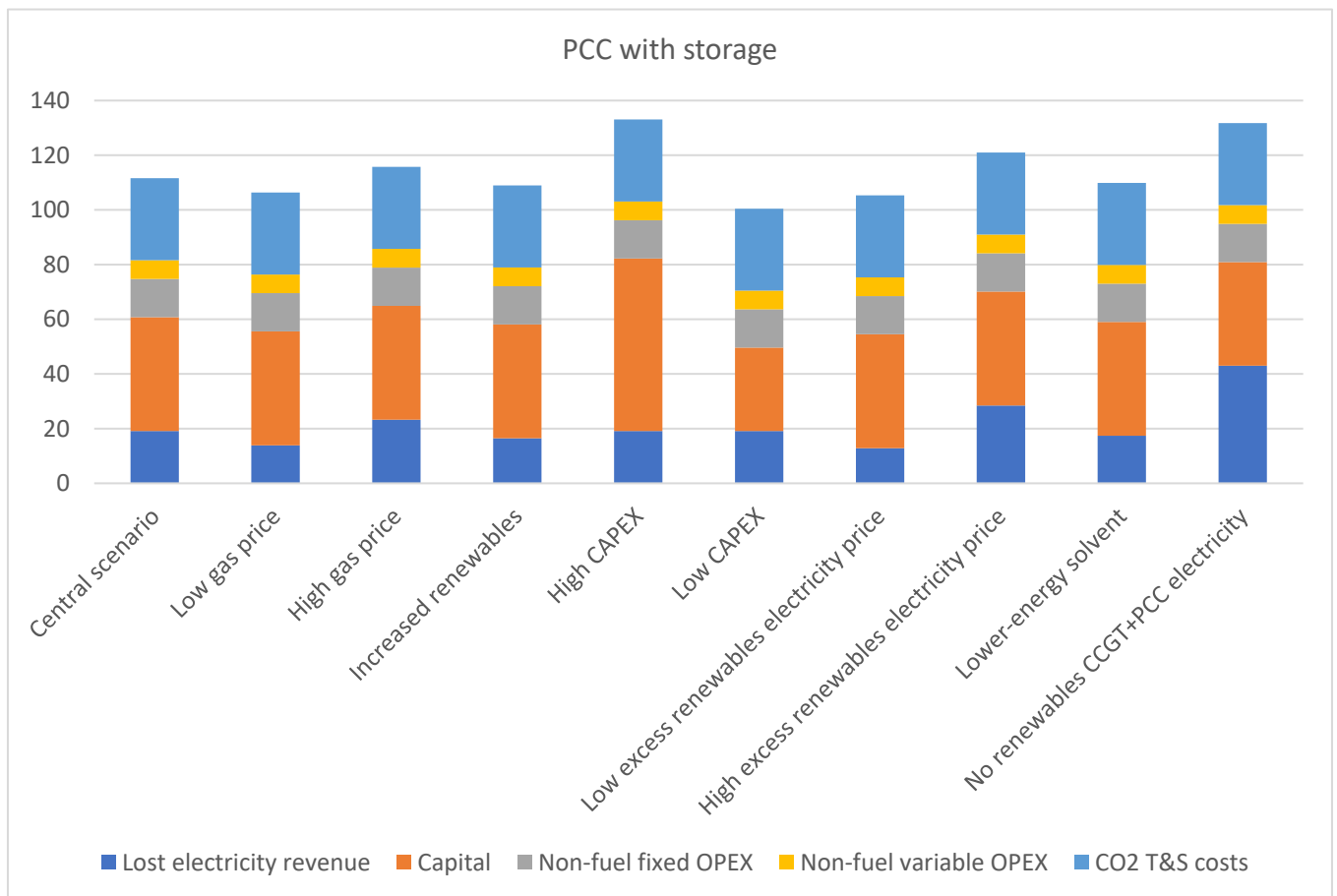
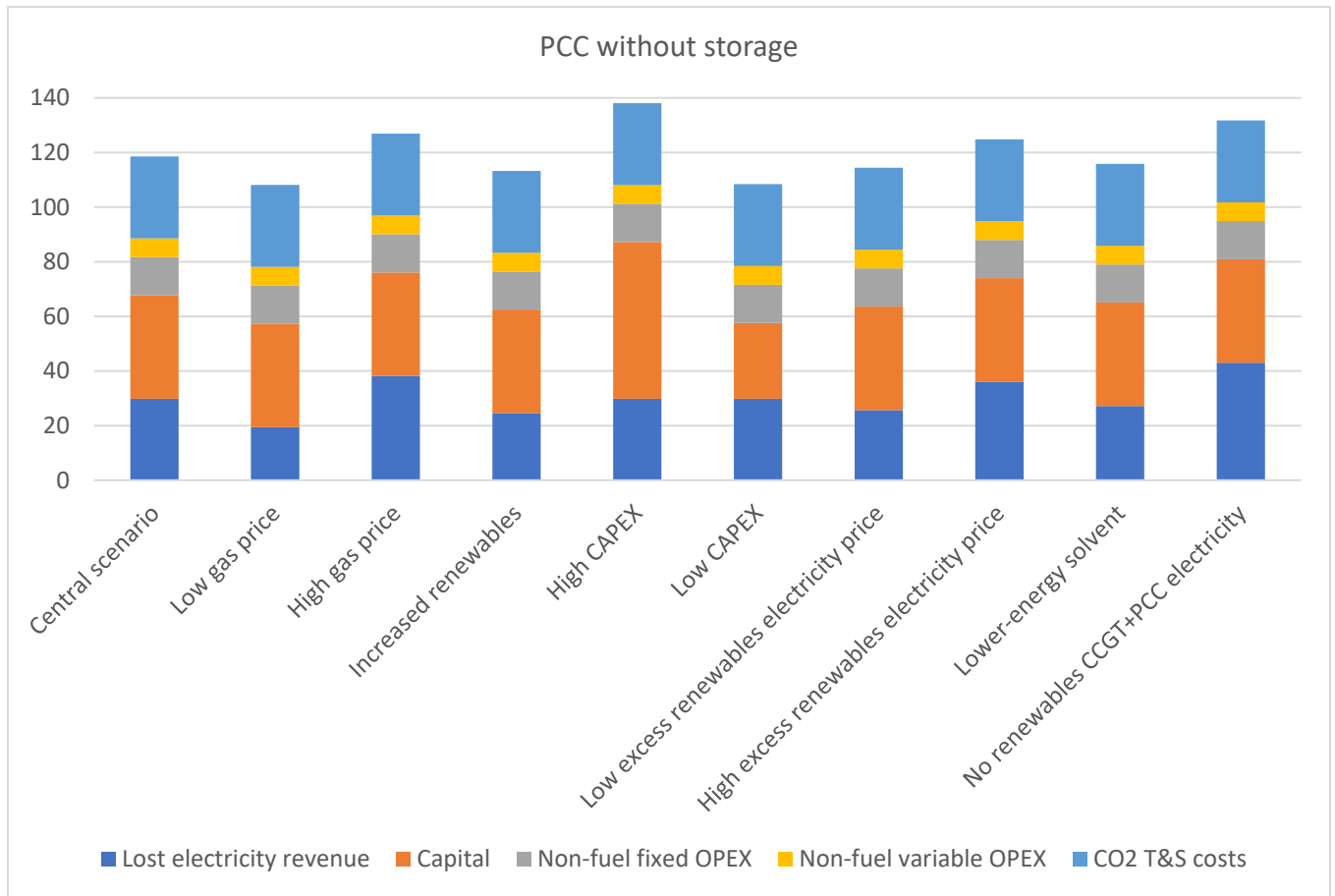
Based on the assumptions for TEA inputs in this report there is a slight advantage in capture cost for the MCFC vs conventional amine post-combustion capture under all conditions. But it must be emphasised that the relative costs are very sensitive to project-specific factors such as capital cost as well as the potential performance of the capture systems.

The use of CESAR1 instead of MEA gives a small reduction in capture cost (order 3%) if other costs are assumed to remain the same, but this reduction would be offset if solvent management costs were increased by 30-40%.

In future electricity systems with extended periods when variable renewable electricity supply is in excess of demand (excluding special measures to use up the surplus such as hydrogen production) the use of solvent storage to shift the electricity output penalty for solvent regeneration from periods of high electricity value to low electricity value could give some marginal cost improvements as well as provide system security benefits¹².

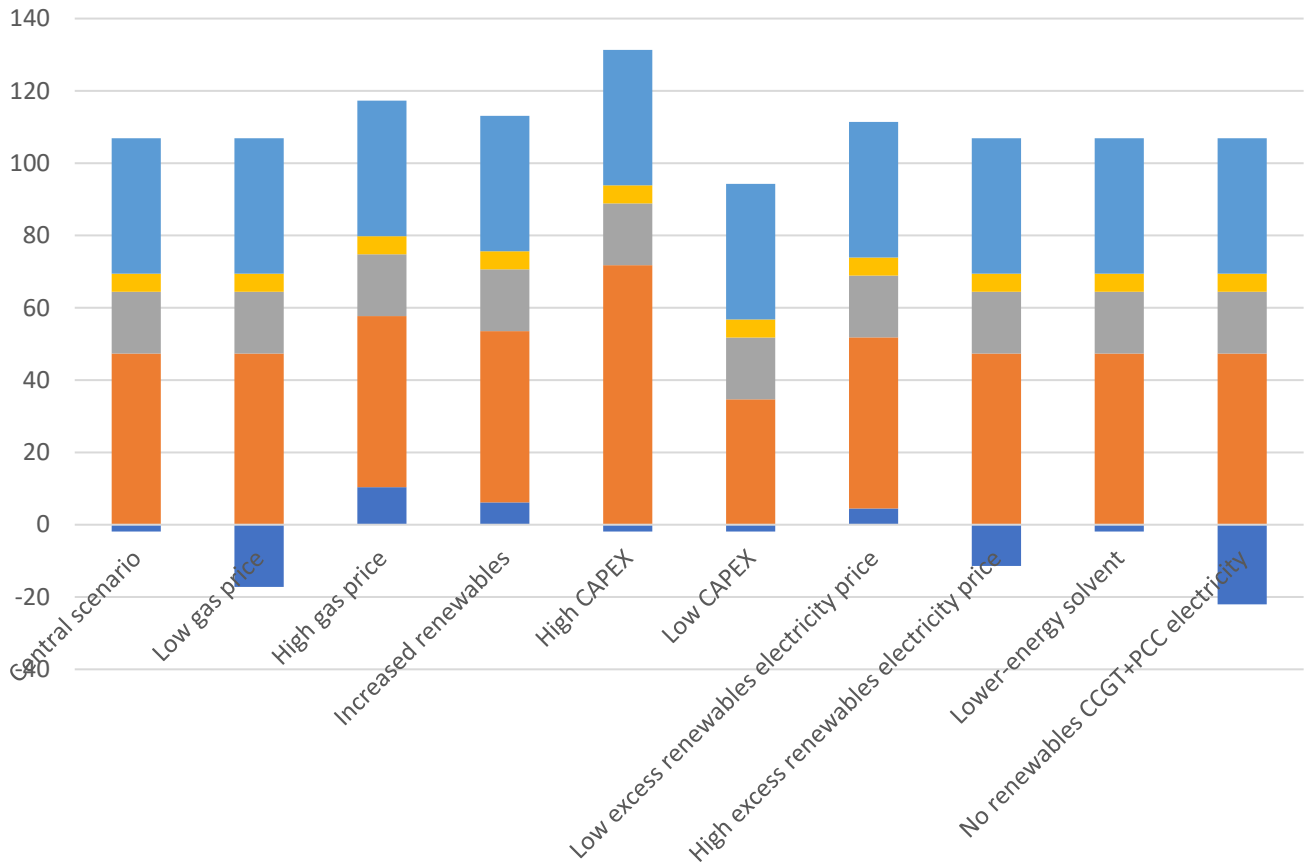
¹² <https://www.linkedin.com/pulse/big-boosts-beat-blackouts-designing-power-ccs-support-jon-gibbins>

Biomass CO₂ capture and storage costs with amine PCC

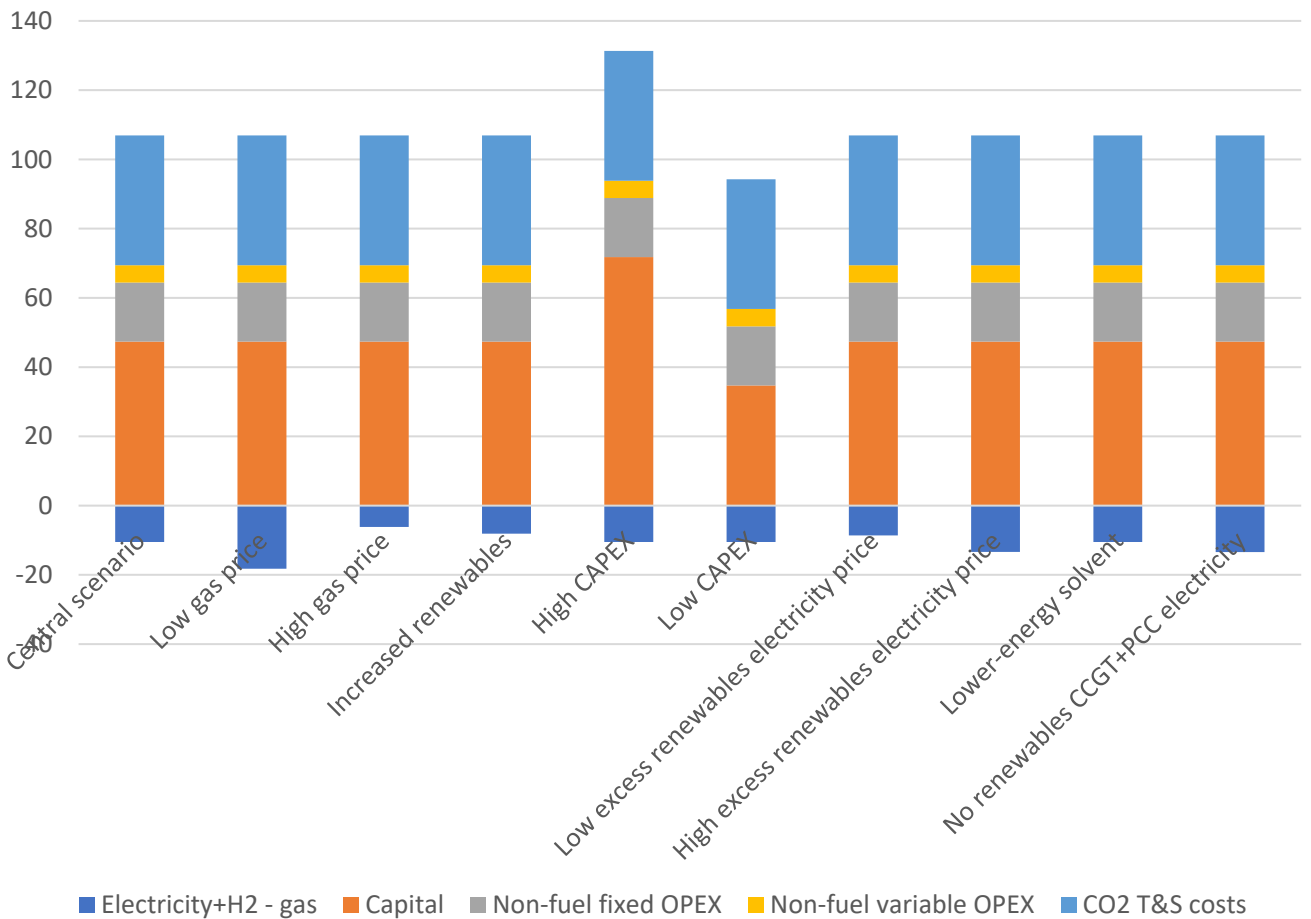


Biomass CO₂ capture and storage costs with MCFC

MCFC - all electricity



MCFC - electricity+H2



■ Electricity+H2 - gas
 ■ Capital
 ■ Non-fuel fixed OPEX
 ■ Non-fuel variable OPEX
 ■ CO2 T&S costs

Annex 1 Data from AECOM study

Table 28. EfW Benchmark - Configuration summary

Item	Description
Base Process Plant	Existing EfW plant (not new build)
Waste treatment capacity	350,000 tpa of Municipal Solid Waste (MSW)
Power output	29 MW gross electrical output 25 MW net electrical capacity without carbon capture (based on typical performance of an EfW plant in the UK) 9 MW net electrical capacity with carbon capture
Flue gas output	237 tph 12 mol% CO ₂
Flue gas treatment	SNCR to control NO _x Acid-gas scrubbing to control SO _x Activated carbon injection to control heavy metal emissions Bag filters to control particulates
Carbon Capture Plant	Post Combustion MEA solvent
Additional flue gas pre-treatment for capture plant	Potential limited modifications to existing acid-gas abatement system to reduce SO _x Flue gas blower to increase pressure and allow admission into downstream process units Direct contact cooler to reduce temperature, with additional caustic treatment for SO _x reduction
Capture	Packed bed absorber with water wash prior to discharge Packed bed stripper column Basic thermal integration of stripper and absorber columns Steam powered reboiler on stripper column Single stage thermal reclaiming
Compression	Single compression train
Conditioning	Deoxygenation Triethylene Glycol (TEG) dehydration – other dehydration technology is available if TEG carryover exceeds pipeline operator requirements. Cooling of CO ₂ product
Solvent	35% w/w Monoethanolamine (MEA)
CO ₂ capture level	95% of CO ₂ emissions from flue gas during normal operation
Operational hours	7,446 hours/year (8760 hours * 85%)
CO ₂ export pressure	27.5 barg for gathering network
Mass of CO ₂ captured	42 tph (1000 tpd)
Steam supply	46 MW from EfW plant This steam use represents the overall heat load of the capture plant
Electricity supply	7 MW from EfW plant

Table 58. Molten Carbonate Fuel Cell – EfW Configuration summary

Item	Description
Base Process Plant	Existing EfW Plant (not new build)
Waste treatment capacity	350,000 tpa of Municipal Solid Waste (MSW)
Power output	29 MW gross electrical output 25 MW net electrical capacity without carbon capture 52 MW net electrical capacity with carbon capture. The additional electricity is generated by the MCFC.
Flue gas output	237 tph 12 mol% CO ₂
Flue gas treatment	SNCR to control NO _x Acid-gas scrubbing to control SO _x Activated carbon injection to control heavy metal emissions Bag filters to control particulates
Carbon Capture Plant	Post Combustion MCFC
Power output	26.3 MW net electrical output (from MCFC)
Additional flue gas pre-treatment for capture plant	Flue gas blower to increase pressure Limestone flue gas desulphurisation to further reduce SO _x Bag filters to further reduce particulates Catalytic oxidation to oxidise residual H ₂ and CO and generate heat
Capture	Desulphurisation of natural gas fuel input Molten carbonate fuel cell for separation of CO ₂ from flue gas Shift reactor to convert residual CO in anode outlet gas Condenser to remove H ₂ O from anode outlet gas Thermal integration system Steam turbine
Compression	Single compression train
Conditioning	Cryogenic CO ₂ separation unit CO ₂ separation from hydrogen recycle using methanol contacting
CO ₂ capture level	96% of CO ₂ emissions from flue gas during normal operation ~100% of CO ₂ emissions from natural gas used
Operational hours	7,446 hours/year (8760 hours * 85%)
CO ₂ export pressure	27.5 barg for gathering network
Mass of CO ₂ captured	53 tph (1,275 tpd) as CO ₂ Liquid phase The CO ₂ is generated in the liquid phase because of the cryogenic conditioning equipment used. This would be an advantage for export to higher pressure pipelines as the pressure can be increased by pumping rather than compression. If gas phase CO ₂ is required at the export pressure assumed in this scenario, then regasification equipment and additional thermal energy would be required. These additional costs would increase the LCOC.
Natural gas supply	5 tph
Steam supply	No steam required from EfW plant during normal operation
Electricity supply	No electricity required from EfW plant during normal operation

EfW capital costs

Table 29. EfW Benchmark - Capital cost

Item	Cost
EPC Costs	
Flue Gas Pre-Treatment	£2.8m
Capture Technology	£18.7m
Conditioning	£0.9m
Compression	£2.9m
Auxiliary Systems	£36.1m
Civil works	£14.4m
Total EPC	£75.8m
Project Development Costs	
Land Requirements	£0.1m
Utility & Infrastructure Connections	£0.8m
Consultancy	£0.8m
Planning & Other Regulatory	£1.5m
Developer's Costs	£5.3m
Start-Up & Commissioning	£3.8m
Total Project Development	£12.3m
Total Capital Cost	
Total Capital Cost	£88.0m
Contingency	10%
Grand Total CAPEX	£96.8m

Table 59. Molten Carbonate Fuel Cell – EfW Capital cost

Item	Cost
EPC Costs	
Flue Gas Pre-Treatment	£15.6m
Capture Technology	£14.2m
Conditioning	£3.9m
Compression	£6.9m
Auxiliary Systems	£38.0m
Civil works	£17.1m
Total EPC	£95.8m
Project Development Costs	
Land Requirements	£0.1m
Utility & Infrastructure Connections	£1.0m
Consultancy	£1.0m
Planning & Other Regulatory	£1.9m
Developer's Costs	£6.7m
Start-Up & Commissioning	£4.8m
Total Project Development	£15.4m
Total Capital Cost	
Total Capital Cost	£111.2m
Contingency	10%
Grand Total CAPEX	£122.3m

EfW operating costs

Table 30. EfW Benchmark - Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£0.9m
Administration and other overheads	£1.5m
Maintenance	£2.4m
Total fixed OPEX	£4.7m
Variable Costs	
Electricity	£3.8m
Steam supply	£11.6m
Solvent	£0.4m
Other chemicals and consumables	£0.6m
Wastes	£1.1m
Plant auxiliary	£0.2m
Total variable OPEX	£17.7m
Total Operating Cost	
Total Operating Cost	£22.4m
Contingency	10%
Grand Total OPEX	£24.7m

Table 60. Molten Carbonate Fuel Cell – EfW Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£0.9m
Administration	£1.8m
Maintenance	£3.1m
Total fixed OPEX	£5.8m
Variable Costs	
Natural gas	£14.8m
Electricity	-£13.3m
Steam supply	£0.0m
MCFC replacement	£1.4m
Other chemicals and consumables	£0.0m
Wastes	£0.1m
Plant auxiliary	£0.2m
Total variable OPEX	£3.2m
Total Operating Cost	
Total Operating Cost	£9.0m
Contingency	10%
Grand Total OPEX	£9.9m

Annex 2 Hydrogen production cost estimates

Based on data from <https://www.gov.uk/government/publications/hydrogen-production-costs-2021>

Technology	Unit	Notes	SMR	SMR	ATR	ATR	GHR	GHR
Commissioning Year			2020	2020	2020	2020	2025	2025
Reference plant size	MW		300	1000	300	1000	300	1000
Availability/Maximum load factor	%		95%	95%	95%	95%	95%	95%
CO2 capture rate (set at 95% for SMR)	%		95%	95%	95%	95%	96%	96%
Thermal conversion efficiency (kWh input fuel or heat / kWh H2 HHV)*	kWh input fuel or heat (HHV) per kWh H2 HHV output	Medium	1.4	1.4	1.2	1.2	1.1	1.1
Electrical conversion efficiency	kWh electric input per kWh H2 HHV output	Medium			0.06	0.06	0.04	0.04
Operating lifetime	Years		40	40	40	40	40	40
CAPEX	£/kW H2 HHV	Medium	774	585	909	613	874	560
Construction period	Years		3	3	3	3	3	3
Construction phasing year)	%	Year 1	33%	33%	33%	33%	33%	33%
	%	Year 2	33%	33%	33%	33%	33%	33%
	%	Year 3	33%	33%	33%	33%	33%	33%
Fixed OPEX	£/KW H2 HHV/year	Medium	28.07	28.07	26.99	26.99	26.99	26.99
Variable OPEX	£/KWh H2 HHV	Medium	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Implied natural gas conversion efficiency	HHV basis		73.8%	73.8%	83.5%	83.5%	89.7%	89.7%
Implied energetic conversion efficiency	HHV basis		73.8%	73.8%	79.6%	79.6%	86.4%	86.4%
Hydrogen for electricity using Gas Turbine fuelled by hydrogen with a 58.5% LHV overall efficiency	HHV basis		0.000	0.000	0.085	0.085	0.061	0.061
Net conversion efficiency	HHV basis		73.8%	73.8%	71.1%	71.1%	80.4%	80.4%
	LHV basis		69.2%	69.2%	66.6%	66.6%	75.3%	75.3%
CO2 capture and stored based on net conversion efficiency	tCO2/MWh HHV		0.238	0.238	0.247	0.247	0.220	0.220
CO2 emitted	tCO2/MWh HHV		0.013	0.013	0.013	0.013	0.010	0.010

Estimated values for hydrogen produced from natural gas with CCS for a range of fuel prices

Technology	Units	Notes	SMR	SMR	ATR	ATR	GHR	GHR
Commissioning Year			2020	2020	2020	2020	2025	2025
Reference plant size	MW		300	1000	300	1000	300	1000
Economic lifetime	Years		25	25	25	25	25	25
Return on investment (ROI - annual return on outstanding capital)			10%	10%	10%	10%	10%	10%
Capital charges	% of CAPEX per year		11.02%	11.02%	11.02%	11.02%	11.02%	11.02%
Charges during construction (based on 50% of additional capital for 1 year)		Year 1	12.90	9.75	15.15	10.21	14.56	9.33
		Year 2	39.99	30.22	46.96	31.65	45.14	28.91
		Year 3	69.80	52.75	81.96	55.24	78.77	50.45
Final CAPEX at start of operation	£/kW H2 HHV		896.77	677.70	1053.06	709.73	1012.07	648.24
Natural gas price	£/MWhth HHV	Low	10	10	10	10	10	10
		Medium	35	35	35	35	35	35
		High	55	55	55	55	55	55
Cost of hydrogen at a range of natural gas prices, median ROI only								
Capital charges	£/MWh H2 HHV		11.87	8.97	13.94	9.40	13.40	8.58
Fixed OPEX	£/MWh H2 HHV		3.37	3.37	3.24	3.24	3.24	3.24
Variable OPEX	£/MWh H2 HHV		0.10	0.10	0.10	0.10	0.10	0.10
CO2 T&S @ £30/tCO2	£/MWh H2 HHV		7.14	7.14	7.42	7.42	6.61	6.61
CO2 emissions @ £150/tCO2	£/MWh H2 HHV		1.88	1.88	1.95	1.95	1.48	1.48
Fuel (based on net conversion efficiency)	£/MWh H2 HHV	Low	13.55	13.55	14.07	14.07	12.44	12.44
	£/MWh H2 HHV	Medium	47.43	47.43	49.23	49.23	43.55	43.55
	£/MWh H2 HHV	High	74.53	74.53	77.37	77.37	68.44	68.44
Hydrogen value	£/MWh H2 HHV	Low	37.92	35.02	40.72	36.17	37.28	32.46
	£/MWh H2 HHV	Medium	71.79	68.89	75.88	71.34	68.39	63.57
	£/MWh H2 HHV	High	98.89	95.99	104.02	99.47	93.28	88.46

		Central scenario	Low gas price	High gas price	Increased renewables	High CAPEX	Low CAPEX	Low excess renewables electricity price	High excess renewables electricity price	Lower-energy solvent	Plus higher cost solvent
Excess renewables time	% of year	50%	50%	50%	70%	50%	50%	50%	50%	50%	50%
Excess renewables electricity price	£/MWh	20	20	20	20	20	20	0	50	20	20
Amine specific reboiler duty reduction	% of normal SRD	100%	100%	100%	100%	100%	100%	100%	100%	85%	85%
Solvent cost multiple (applied to variable OPEX)		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.4
Lost generation at 1:4 ratio	MWe	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	8.925	8.925
Fraction of high price time energy penalty shifted to low price period	% of year	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Capital increase for solvent storage if used		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CCGT+PCC added CO2 capture rate		95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Natural gas price	£/MWhth HHV	35	10	55	35	35	35	35	35	35	35
CO2 transport and storage cost	£/tCO2	30	30	30	30	30	30	30	30	30	30
CO2 emission cost	£/tCO2	150	150	150	150	150	150	150	150	150	150
Project economic life	Years	15	15	15	15	10	15	15	15	15	15
Return on investment (ROI - annual return on outstanding capital)		10%	10%	10%	10%	15%	5%	10%	10%	10%	10%
Capital charges	% of CAPEX per year	13.15%	13.15%	13.15%	13.15%	19.93%	9.63%	13.15%	13.15%	13.15%	13.15%
CCGT+PCC electricity price											
CAPEX element (£/MWh)	£/MWh	40.00	40.00	40.00	66.67	40.00	40.00	40.00	40.00	40.00	40.00
Fuel cost	£/MWh	70.00	20.00	110.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00
CO2 T&S cost	£/MWh	10.55	10.55	10.55	10.55	10.55	10.55	10.55	10.55	10.55	10.55
CO2 emissions cost		2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78
Total CCGT+PCC electricity price	£/MWh	123.32	73.32	163.32	149.99	123.32	123.32	123.32	123.32	123.32	123.32
Marginal CCGT+PCC electricity price	£/MWh	83.32	33.32	123.32	83.32	83.32	83.32	83.32	83.32	83.32	83.32
Electricity price when excess renewables	£/MWh	20.00	20.00	20.00	20.00	20.00	20.00	0.00	50.00	20.00	20.00
Amine PCC costs per hour for 8000 hrs/yr operation											
Capital	£/hr	1590.83	1590.83	1590.83	1590.83	2410.95	1165.74	1590.83	1590.83	1590.83	1590.83
Non-fuel fixed OPEX	£/hr	587.50	587.50	587.50	587.50	587.50	587.50	587.50	587.50	587.50	587.50
Non-fuel variable OPEX	£/hr	287.50	287.50	287.50	287.50	287.50	287.50	287.50	287.50	287.50	402.50
Lost electricity value when excess renewables price	£/hr ave	175.00	175.00	175.00	245.00	175.00	175.00	0.00	437.50	159.25	159.25
Lost electricity value when CCGT+PCC price	£/hr ave	1079.05	641.55	1429.05	787.43	1079.05	1079.05	1079.05	1079.05	981.94	981.94
CO2 T&S costs	£/hr	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00
Total costs per hour	£/hr	4979.88	4542.38	5329.88	4758.26	5800.00	4554.79	4804.88	5242.38	4867.02	4982.02
Costs per tonne of CO2 from biomass	£/tCO2 from biomass	118.57	108.15	126.90	113.29	138.10	108.45	114.40	124.82	115.88	118.62

		Solvent storage to shift energy penalty timing	Low gas price	High gas price	Increased renewables	High CAPEX	Low CAPEX	Low excess renewables electricity price	High excess renewables electricity price	Lower-energy solvent	Plus higher cost solvent	No renewables CCGT+PCC electricity	Solvent storage - cost increase to match no storage
Excess renewables time	% of year	50%	50%	50%	70%	50%	50%	50%	50%	50%	50%	0%	50%
Excess renewables electricity price	£/MWh	20	20	20	20	20	20	0	50	20	20	100	20
Amine specific reboiler duty reduction	% of normal SRD	100%	100%	100%	100%	100%	100%	100%	100%	85%	85%	100%	100%
Solvent cost multiple (applied to variable OPEX)		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.3	1.0	1.0
Lost generation at 1:4 ratio	MWe	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	8.925	8.925	10.5	10.5
Fraction of high price time energy penalty shifted to low price period	% of year	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	0%	50%
Capital increase for solvent storage if used		10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	0%	28%
CCGT+PCC added CO2 capture rate		95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Natural gas price	£/MWhth HHV	35	10	55	35	35	35	35	35	35	35	35	35
CO2 transport and storage cost	£/tCO2	30	30	30	30	30	30	30	30	30	30	30	30
CO2 emission cost	£/tCO2	150	150	150	150	150	150	150	150	150	150	150	150
Project economic life	Years	15	15	15	15	10	15	15	15	15	15	15	15
Return on investment (ROI - annual return on outstanding capital)		10%	10%	10%	10%	15%	5%	10%	10%	10%	10%	10%	10%
Capital charges	% of CAPEX per year	13.15%	13.15%	13.15%	13.15%	19.93%	9.63%	13.15%	13.15%	13.15%	13.15%	13.15%	13.15%
CCGT+PCC electricity price													
CAPEX element (£/MWh)	£/MWh	40.00	40.00	40.00	66.67	40.00	40.00	40.00	40.00	40.00	40.00	20.00	40.00
Fuel cost	£/MWh	70.00	20.00	110.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00
CO2 T&S cost	£/MWh	10.55	10.55	10.55	10.55	10.55	10.55	10.55	10.55	10.55	10.55	10.55	10.55
CO2 emissions cost		2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78
Total CCGT+PCC electricity price	£/MWh	123.32	73.32	163.32	149.99	123.32	123.32	123.32	123.32	123.32	123.32	103.32	123.32
Marginal CCGT+PCC electricity price	£/MWh	83.32	33.32	123.32	83.32	83.32	83.32	83.32	83.32	83.32	83.32	83.32	83.32
Electricity price when excess renewables	£/MWh	20.00	20.00	20.00	20.00	20.00	20.00	0.00	50.00	20.00	20.00		20.00
Amine PCC costs per hour for 8000 hrs/yr operation													
Capital	£/hr	1749.92	1749.92	1749.92	1749.92	2652.04	1282.32	1749.92	1749.92	1749.92	1749.92	1590.83	2036.27
Non-fuel fixed OPEX	£/hr	587.50	587.50	587.50	587.50	587.50	587.50	587.50	587.50	587.50	587.50	587.50	587.50
Non-fuel variable OPEX	£/hr	287.50	287.50	287.50	287.50	287.50	287.50	287.50	287.50	287.50	359.38	287.50	287.50
Lost electricity value when excess renewables price	£/hr ave	262.50	262.50	262.50	297.50	262.50	262.50	0.00	656.25	238.88	238.88	0.00	262.50
Lost electricity value when CCGT+PCC price	£/hr ave	539.53	320.78	714.53	393.72	539.53	539.53	539.53	539.53	490.97	490.97	1808.10	539.53
CO2 T&S costs	£/hr	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00
Total costs per hour	£/hr	4686.94	4468.19	4861.94	4576.13	5589.07	4219.34	4424.44	5080.69	4614.76	4686.63	5533.93	4973.29
Costs per tonne of CO2 from biomass	£/tCO2 from biomass	111.59	106.39	115.76	108.96	133.07	100.46	105.34	120.97	109.88	111.59	131.76	118.41

		Central scenario	Low gas price	High gas price	Increased renewables	High CAPEX	Low CAPEX	Low excess renewables electricity price	High excess renewables electricity price
MCFC costs per hour for 8000 hrs/yr operation									
Capital	£/hr	2009.91	2009.91	2009.91	2009.91	3046.07	1472.83	2009.91	2009.91
Non-fuel fixed OPEX	£/hr	725.00	725.00	725.00	725.00	725.00	725.00	725.00	725.00
Non-fuel variable OPEX	£/hr	212.50	212.50	212.50	212.50	212.50	212.50	212.50	212.50
Electricity value when excess renewables (-ve is export)	£/hr ave	-270.00	-270.00	-270.00	-378.00	-270.00	-270.00	0.00	-675.00
Electricity value when CCGT+PCC (-ve is export)	£/hr ave	-1664.82	-989.82	-2204.82	-1214.89	-1664.82	-1664.82	-1664.82	-1664.82
Natural gas costs	£/hr	1855.00	530.00	2915.00	1855.00	1855.00	1855.00	1855.00	1855.00
CO2 T&S costs	£/hr	1590.00	1590.00	1590.00	1590.00	1590.00	1590.00	1590.00	1590.00
Total costs per hour	£/hr	4457.59	3807.59	4977.59	4799.51	5493.75	3920.51	4727.59	4052.59
Costs per tonne of CO2 from biomass	£/tCO2 from biomass	105.03	89.71	117.28	113.08	129.44	92.37	111.39	95.49
MCFC economics with some output shifted to H2									
Fraction of electricity output shifted to H2		70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%
Hydrogen output vs. lost electricity	MWh HHV/MWhe	140.00%	140.00%	140.00%	140.00%	140.00%	140.00%	140.00%	140.00%
Revised electricity output	MW	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Revised hydrogen output	MW HHV	26.46	26.46	26.46	26.46	26.46	26.46	26.46	26.46
Hydrogen value	£/MWh HHV	65.00	35.00	92.00	65.00	65.00	65.00	65.00	65.00
MCFC costs per hour for 8000 hrs/yr operation									
Capital	£/hr	2009.91	2009.91	2009.91	2009.91	3046.07	1472.83	2009.91	2009.91
Non-fuel fixed OPEX	£/hr	725.00	725.00	725.00	725.00	725.00	725.00	725.00	725.00
Non-fuel variable OPEX	£/hr	212.50	212.50	212.50	212.50	212.50	212.50	212.50	212.50
Electricity value when excess renewables (-ve is export)	£/hr ave	-81.00	-81.00	-81.00	-113.40	-81.00	-81.00	0.00	-202.50
Electricity value when CCGT+PCC (-ve is export)	£/hr ave	-499.45	-296.95	-661.45	-364.47	-499.45	-499.45	-499.45	-499.45
Hydrogen value	£/hr	-1719.90	-926.10	-2434.32	-1719.90	-1719.90	-1719.90	-1719.90	-1719.90
Natural gas costs	£/hr	1855.00	530.00	2915.00	1855.00	1855.00	1855.00	1855.00	1855.00
CO2 T&S costs	£/hr	1590.00	1590.00	1590.00	1590.00	1590.00	1590.00	1590.00	1590.00
Total costs per hour	£/hr	4092.06	3763.36	4275.64	4194.64	5128.22	3554.99	4173.06	3970.56
Costs per tonne of CO2 from biomass	£/tCO2 from biomass	96.42	88.67	100.74	98.83	120.83	83.76	98.32	93.55

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