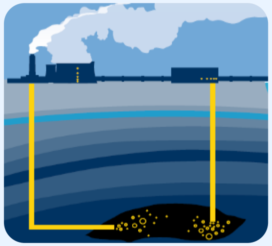

Extension to Fuel Switching Engagement Study (FSES) – Deep decarbonisation of UK industries

Assumptions log

the CCC

April 2019

elementenergy

Emrah.Durusut@element-energy.co.uk
Sophie.Lyons@element-energy.co.uk
Michael.Joos@element-energy.co.uk

This document outlines the assumptions informing the net zero options for UK industry

Context of the study

- In a previous study for BEIS, Element Energy and Jacobs considered the potential of fuel switching in industrial heating applications. The study covered just over half of fossil fuel use in manufacturing (120 TWh of a total 215 TWh).

- The CCC commissioned Element to extend the study so that abatement of all manufacturing combustion emissions by fuel switching was considered.

- This study looked to extend the analysis in the BEIS report by:
  - Including the abatement of emissions from internal fuels (produced from fossil fuel feedstocks as part of the manufacturing process and then combusted to produce heat);
  - Combining technologies (e.g. considering the use of heat pumps in conjunction with hydrogen) to maximise fuel switching when individual technologies have substitution limits.

- Consideration of abatement of internal fuel combustion emissions led to consideration of CCS in the analysis, as an option to enable industries using internal fuels to reach low emissions.

- This document sets out the assumptions behind this analysis.

Overview of abatement technologies

Roll-out scenarios

Calculating cost premiums and abatement costs

Technology cost and characteristic assumptions

Fuel cost and emissions assumptions

Overview of abatement technologies

Key abatement options considered

- **Chemicals, Food & Drink, Paper, Vehicles, Non metallic minerals, Non ferrous metal, Secondary steel production & processing, Other industry:** Fuel switching
- **Primary iron production**: Blast furnace + CCS; HISarna + CCS
  - Note that key stakeholders are considering Syngas treatment at Blast furnaces (as an interim measure before CCUS can be implemented) and are keen to understand the overall emissions implications
- **Refining**: Hydrogen production with CCS and fuel switching to hydrogen (*including internal fuels*); CCS
- **Ethylene**: CCS; fuel switching (*including internal fuels*)
- **Cement**: CCS with current level of biomass; CCS + increased fuel switching to biomass
- **Ammonia**: CCS; process switching (electrolysis for hydrogen production)

Key assumptions

- **Fuel switching:** we assume that all industrial combustion applications in the sectors mentioned above could be replaced with hydrogen in the long term. This does not include CHP applications (NB current Hy4Heat findings suggest that CHP gas engines may be challenging to convert to 100% hydrogen).
  - **For the purpose of this study we assume that processes driven by combustion of oil (including many sites which are likely to be off-grid) can be switched to hydrogen.**
- **CCS:** we assume that 90% abatement rates can be applied to all emissions streams in the sectors above, and that more costly CCS technologies could increase abatement rates to 99% on the same emissions streams (exceptions set out on the following slides). We also assume that hydrogen can be used for heating.

Specific technology choices depend on the deployment scenario

Deployment levels in different scenarios reflect the cost of abatement

- Three scenarios reflecting different levels of deployment of fuel switching and CCS technologies have been modelled
- The level of deployment depends on the in-year abatement costs in 2050[1]
  - **Core:**
    - Fuel switching / CCS with abatement costs up to £100/tCO_2 are applied
    - Fuel switching: only electrification technologies included
    - CCS is applied with a maximum abatement rate of 90%
  - **Further Ambition:**
    - Fuel switching / CCS with abatement costs up to £400/tCO_2 are applied
    - Fuel switching: hydrogen and electrification technologies (+biomass where it can be combined with CCS)
    - CCS is applied with a maximum abatement rate of 90%
  - **Speculative:**
    - All Fuel switching / CCS options are applied without a cost limit
    - Fuel switching: hydrogen and electrification technologies (+biomass where it can be combined with CCS)
    - CCS is applied with abatement rate of 99%

1) Abatement cost in 2050 given fuel prices and installed abatement capacity in this year. This approach has been implemented on request.

CCS – specific technology choices

CCS technology options

- CCS is applied in the 5 sectors **Iron & Steel, Cement, Refining, Ethylene, Ammonia**
- Two **sets of CCS technologies** are considered:
  - "Best available technology": calcium looping and second generation amines and blends, which are of lower cost but become available later than more mature technologies
  - "Most mature technology": first generation amines, which are the most mature capturing technology but have a higher cost
- For Iron and steel, **CCS in combination with HIsarna** applied to the primary production processes can be chosen as a further option. This lowers the CCS cost, as carbon capture only needs to be applied to a smaller share of the emissions of the steel plant, since a 20% emission reduction is already achieved through the switch to the HIsarna process, which has been assumed to come at a 50% CAPEX premium but significantly reduces fuel costs and otherwise does not incur higher OPEX.
- CCS is applied in two steps, relating to a 90% and 99% efficiency of the capture technology.
- The net capture rate is the product of the efficiency of the capture technology and the treatment rate of emissions of the emission site

net capture rate = treatment rate * capture efficiency

- All sectors have a 99% or 100% treatment rate, except:
  - The Refining sector, where a 90% treatment rate is assumed and therefore only net capture rates of 81% and 89% respectively are achieved
  - The steel sector in the Core scenario, for the cases below, when the treatment of 60% of emissions is within the cost range of the Core scenario, but treating the remaining emissions is above the cost limit; therefore only net capture rates of 90%*60%=54% and 99%*60%=59% can be achieved.
    - best available CCS technologies
    - most mature CCS technologies in combination with HIsarna

High level abatement costs - CCS

Overview of abatement costs for CCS measures

Technology	Abatement cost Best available technology[1]	Abatement cost Most mature technology
CCS – Primary iron production	119 £/t for 90% abatement 238 £/t for increase from 90% to 99%	175 £/t for 90% abatement 350 £/t for increase from 90% to 99%
CCS - Refining	121 £/t for 90% abatement 242 £/t for increase from 90% to 99%	169 £/t for 90% abatement 338 £/t for increase from 90% to 99%
CCS - Cement	81 £/t for 90% abatement 162 £/t for increase from 90% to 99%	129 £/t for 90% abatement 258 £/t for increase from 90% to 99%
CCS – Ethylene/Ammonia	115 £/t for Ethylene 30 £/t for Ammonia	190 £/t for Ethylene 30 £/t for Ammonia

- CCS abatement costs shown are levelized cost per captured tCO_2 in 2050
- CCS costs are calculated separately for 90% and 99% net abatement; abatement cost per kg is multiplied by a factor of 2.0 for the higher abatement level, to reflect the higher cost of the increased capture rate (this is applied for the levelized cost of abatement as well as across CAPEX, OPEX and fuel costs). This factor draws on evidence from: IEAGHG (March 2019), *Towards zero emissions CCS from power stations using higher capture rates or biomass*.
- Cement emissions are split into inland cement and cement at shoreline, assuming 70% inland cement; for inland cement £6/tCO2 have been added for CO2 transport costs corresponding to an onshore pipeline of 120km distance and 1Mtpa flow rate. This corresponds to the average distance of cement sites to potential CO2 shipping ports identified in a BEIS study. As several cement sites have annual emission rates lower than 1Mtpa, building dedicated pipelines for these sites could come at a higher cost (e.g. approx. 11£/tCO2 for a 0.5Mtpa site)

1) Best available technology: calcium looping and 2nd generation amines and blends; most mature technology: 1st generation amines

High level abatement costs – fuel switching

Overview of abatement costs for fuel switching measures

Technology	Abatement cost range
Hydrogen	65 to 240 £/t (2050)
Heat pumps & hydrogen	11 to 110 £/t (2050)
Electrification (including heat pumps)	-92 to 400 £/t (2050)

- Fuel switching costs shown above are calculated for 100% abatement of relevant sites in 2050. Costs variations are partly due to the assumed price of different counterfactual fuels (and hence different fuel cost differentials), and variation in site sizes which leads to different impacts of capital cost premiums in the overall abatement cost.
- Note that heat pumps are applicable in certain applications, but due to their output temperature limitations it is assumed that they can only meet 25% of the energy demand per process, per site (and thus can only replace 25% of fossil fuel demand). In contrast to the Element Energy Fuel Switching study for BEIS (2018), in this study the parallel application of heat pumps and hydrogen technologies is also considered in order to achieve 100% direct emissions abatement.
- Note that the following industries are not included in the fuel switching analysis. This is consistent with these not being included as part of the "Other industry" category as used in the Element Energy analysis for BEIS (2018). These represent 1.5 $MtCO_2e$ in 2016.
  - Buildings and building construction works
  - Constructions and construction works for civil engineering
  - Specialised construction works
  - Mining of coal and lignite
  - Products of agriculture, hunting and related services
  - Constructions and construction works for civil engineering
  - Waste collection, treatment and disposal services; materials recovery services

Technology roll-out scenarios

The same scenarios have been applied to CCS and fuel switching technologies

- 3 roll out scenarios of fuel switching and CCS technologies have been modelled
- They are based on data on dates when technologies will achieve TRL 9 and the lifetimes of the counterfactual technologies, which are assumed to be 25 years.

Scenario	First commercial deployment	Roll out period
Slow	Date when TRL 9 achieved + 5 years	• 38 years (150% * counterfactual lifetime)
Central	Date when TRL 9 achieved	• 5% deployment after 5 years • 15% deployment after 10 years • 55% after 20 years • 90% after 25 years (100% after 27 years)
Fast	Date when TRL 9 achieved	• 20 years (80% * counterfactual lifetime)

- This approach is applied to both CCS and fuel switching technologies
- The exception is the roll out of the most mature CCS technologies in the Central scenario: it assumes a roll out period given by the counterfactual lifetime without the differentiation into further periods, since the most mature technologies don’t have a learning period like the less mature technologies.

Fuel switching technology roll-out: key dates used

The same scenarios have been applied to CCS and fuel switching technologies

- The table below shows the dates of first commercial deployment and full roll out for key fuel switching and CCS technologies in the Central scenario. Where a range is shown, this reflects different requirements for deployment in different industrial sectors.

Technology	Date of first commercial deployment	Date when full roll out achieved	Technology	Date of first commercial deployment	Date when full roll out achieved
100% H2 Fuel Boilers	2025	2052	Electric Steam Boiler (small)	2018	2045
100% H2 Fuel Heaters	2026-2027	2053-2054	Electrode Steam Boiler (large)	2018-2030	2045-2057
All Electric Smelters	2035	2062	H2 fired kiln	2026	2053
Biomass Combustion + O2 enrichment	2018	2045	Biomass Steam Boiler	2018	2045
CL Heat Pump	2025	2052	OL Heat Pump (MVR)	2025	2052
Direct Biomass Reductant	2030	2057	Electric Plasma Gas Heaters	2020-2035	2047-2062
Electric Ceramic Tunnel Kilns	2030	2057	CCS 1st gen. amines	2025	2052
Electric Infra-Red Heaters	2018-2030	2045-2057	CCS calcium looping	2030	2057
Electric Process Heater	2018-2030	2045-2057	CCS 2nd gen. amines & blends	2025	2052

CCS technology roll-out: availability dates and roll out rates

The same scenarios have been applied to CCS and fuel switching technologies

Sector	Most mature technology	TRL 9 achieved	Lifetime (y)	Best available technology	TRL 9 achieved	Lifetime (y)
Cement	1st generation amines	2025	15	Calcium looping	2030	15
Iron & Steel	1st generation amines	2025	15	Calcium looping	2030	15
Refineries	1st generation amines	2025	15	2nd generation amines and blends	2025	15
Ammonia[1]	1st generation amines	2025	15	1st generation amines	2025	15
Ethylene	1st generation amines	2025	15	Calcium looping	2030	15

- The date when calcium looping achieves TRL 9 is set at 2030; whereas a previous study[2] suggested that calcium looping would reach TRL 9 in 2025, we have increased this by 5 years, as we assume a capture rate of 90% for all CCS technologies and calcium looping might not be able to achieve this rate by 2030. The mentioned study suggested a capture rate of 85% for calcium looping in 2025, whereas the other CCS technologies had a capture rate of 90% in 2025, increased from 85% in 2020 (when calcium looping is not yet available but the other technologies are).
- The roll out period is 25 years for each CCS technology (given by the lifetime of the combustion technologies)

1) No significant capture technology required due to CO_2 purity of >=95%; main cost components are compression and transport
2) https://www.gov.uk/government/publications/co2-capture-in-the-uk-cement-chemicals-iron-steel-and-oil-refining-sectors

Overall abatement cost approach and assumptions

Key assumptions

- Cost of capital: 10%
- Discount rate: 3.5%
- Overall abatement cost:

$$\pounds/tCO_2e = \frac{\text{net present cost of measure}}{\text{total discounted lifetime abatement}}$$

  – Where the abatement measure and the baseline (counterfactual) measure have different lifetimes, it is necessary to annualise both numerator and denominator, i.e.

$$\pounds/tCO_2e = \frac{\text{annualised net present cost of measure}}{\text{annualised discounted lifetime abatement}}$$

- "In-year" abatement cost:

$$\pounds/tCO_2e = \frac{\text{Annualised capex premium + annual opex premium (vs counterfactual) for all measures cumulatively installed in given year}}{\text{Emissions abated in given year}}$$

- Avoided carbon costs (through a carbon price) are not included as a saving in either case (in contrast to Element Energy's analysis in the BEIS Fuel switching study)

CCS - cost calculation methodology

Calculation approach

- **Capital costs** in the years of roll out are calculated assuming an additional capacity given by the roll out increment (1/roll out period) multiplied with the baseline emissions of that year; furthermore costs to replace CCS capacity after the end of its lifetime are added in later years; replacement costs in year x are determined given by the capital cost of the year when the CCS capacity to be replaced was added (year "y") multiplied by the ratio of baseline emissions of year x to those in year y.
- **OPEX** is calculated by multiplying specific OPEX (£/tCO_2) by the direct abatement in the year; they also include the cost of transport and storage of the $CO_{2.}$
- **Fuel costs** are calculated using the hydrogen and electricity requirements in CCS plants in any year and the CCC projection of hydrogen and electricity prices; they are calculated by multiplying the direct abatement in the particular year with the specific fuel requirement (kWh/tCO_2) and fuel cost (£/kWh) in that year.
- **The tonnes of CO_2 stored** are taken to be the tonnes of CO_2 directly abated (through CCS) in that year, i.e. not the cumulatively captured CO_2 up to that year and it is assumed that 100% of the captured CO_2 is stored.
- **Typical sizes of emission sites** are based on a database of industrial sites of the steel, refining, cement, ammonia and ethylene sector of a previous CCS study for DECC/BIS
- **In year abatement costs** are calculated by summing the OPEX and fuel cost of this year, adding the annualised capital cost of the installed abatement technology capacity, and dividing by the direct abatement of that year. The installed abatement technology capacity is given by the abatement rate of the year multiplied by the baseline emissions of the year.

Fuel switching – cost calculation methodology and assumptions

Approach and key assumptions for abatement cost calculation

- **Components of abatement cost calculations (overall and in-year):**
  - Capex premium relative to counterfactual
  - Fixed opex premium relative to counterfactual (assumed to scale with capex)
  - Fuel cost premium relative to counterfactual
  - Emissions relative to counterfactual
- **Capex premiums** are calculated using the approach used in the 2018 BEIS fuel switching study: assuming gas counterfactual technologies*, and calculated for specific sites (based on EU-ETS emissions data and fuel consumption data) in order to correctly account for scaling factors.
  - To show the capex associated with abating a specific share of industry emissions, the **total capex across a particular sector-process combination** for a given technology is then scaled by share of emissions of the total for that particular sector-process combination.
  - For the central roll-out scenario and the fast roll-out scenario, in cases when the counterfactual technology is assumed to be replaced early (see rollout scenarios), a "**scrappage factor**" is applied whereby the counterfactual cost in abatement cost calculation is reduced by the same percentage as the lifetime is reduced (e.g. if the lifetime is reduced by 20%, the counterfactual capex is also reduced by 20%).
- **Fuel cost premium and emissions relative to the counterfactual** are calculated for each specific counterfactual fuel type, assuming that all counterfactual technologies have the same efficiencies as those assumed in the BEIS fuel switching study.
  - We have assumed that fuel costs for some different fuel types can be mapped to the costs of gas, coal and oil

*Note that this study does not account for possible additional capital costs to supply hydrogen to sites which are not on the gas grid (i.e. those currently using oil or other liquid fuels)

Overview of abatement technologies

Roll-out scenarios

Calculating cost premiums and abatement costs

Technology cost and characteristic assumptions

Fuel cost and emissions assumptions

CCS – technical assumptions for cost estimates

Emission stream	CCS technology	Typical size of source	Size of smallest sources	Size of largest sources	Treatment rate	Capture technology efficiency
		(ktCO2e/y)	(ktCO2e/y)	(ktCO2e/y)		
Ironmaking - BF BOF	First generation amines	6,800	6,223	7,306	60%/100%	90% /99%
Ironmaking - HISarna	First generation amines	6,800	6,223	7,306	60%/100%	90% /99%
Ethylene	First generation amines	100	50	228	99%	90% /99%
Ammonia	First generation amines	390	320	455	99%	90% /99%
Cement - near coastline	First generation amines	540	231	1,065	99%	90% /99%
Cement - inland	First generation amines	540	231	1,065	99%	90% /99%
Refining	First generation amines	1,090	450	1,630	90%	90% /99%
Ironmaking - BF BOF	Calcium looping	6,800	6,223	7,306	60%/100%	90% /99%
Ironmaking - HISarna	Calcium looping	6,800	6,223	7,306	60%/100%	90% /99%
Ethylene	Calcium looping	100	50	228	99%	90% /99%
Ammonia	First generation amines	390	320	455	99%	90% /99%
Cement - near coastline	Calcium looping	540	231	1,065	99%	90% /99%
Cement - inland	Calcium looping	540	231	1,065	99%	90% /99%
Refining	Advanced amines or blends	1,090	450	1,630	90%	90% /99%

- CCS literature and the cost model used for cost estimates assume relatively low treatment rate (approx. 60%) for steel sites, due to scale (several Mtpa), long time between major overhauls with interventions likely to aim to minimise impact on operation, and no planned new steel mills in the UK; however steel industry stakeholders explained that a 100% treatment of emissions is achievable
- A cost estimate for a 100% treatment has been calculated by scaling up the model's cost estimate to account for capture of flue streams of low concentration, using literature data on capture costs of individual flue streams of steel plants[1]

1) (Wiley et al., 2011), available at: https://www.sciencedirect.com/science/article/pii/S1876610211003626

CCS – cost data

Emission stream	CCS technology	Levelised cost of direct abatement[1]	CAPEX per annual capacity	CAPEX per tCO2 captured	OPEX per tCO2 captured	Electricity requirement per tCO2 captured	Gas requirement per tCO2 captured
		(£/tCO2e)	(£/(tCO2/y))	(£/tCO2)	(£/tCO2)	(kWh/tCO2)	(kWh/tCO2)
Ironmaking - BF BOF – 60%	1st gen. amines	118	178	12	53	114	876
Ironmaking - BF BOF - 100%	1st gen. amines	175	263	18	78	168	1296
Ironmaking – HISarna – 60%	1st gen. amines	68	143	10	21	78	599
Ironmaking - HISarna - 100%	1st gen. amines	128	221	15	51	131	1014
Ethylene	1st gen. amines	190	526	35	87	146	1010
Ammonia	1st gen. amines	30	27	2	21	94	0
Cement - near coastline	1st gen. amines	129	276	18	54	118	904
Cement - inland	1st gen. amines	135	276	18	60	118	904
Refining	1st gen. amines	169	417	28	74	152	1024
Ironmaking - BF BOF – 60%	Calcium looping	80	79	5	44	156	389
Ironmaking - BF BOF - 100%	Calcium looping	119	117	8	64	231	576
Ironmaking - HISarna - 100%	Calcium looping	84	107	8	40	180	451
Ethylene	Calcium looping	115	215	14	57	245	449
Ammonia	1st gen. amines	30	27	2	21	94	0
Cement - near coastline	Calcium looping	81	119	8	39	169	402
Cement - inland	Calcium looping	86	119	8	45	169	402
Refining	Adv. amines or blends	121	283	19	45	152	853

- Cost data is based on CCS cost model representing lifetime cash flow of a CCS plant
- OPEX include the cost of capital (assuming a 10% interest rate) but no fuel cost; levelised cost based on a 3.5% discount rate
- Heating required in the carbon capture plant is assumed to be provided through hydrogen combustion in boilers
- The indirect emissions of the CC plant through hydrogen combustion and use of electricity have been calculated using the CCC's projections for carbon intensity of electricity and hydrogen

1) In 2050

Fuel switching – technology suitability assumptions (note that these suitabilities are applied irrespective of the counterfactual fuel type)

Processes driven by	Process type	Suitable fuel-switching options	Key sectors relying on these processes
Indirect heating	Low temperature	Biomass boilers, hydrogen boilers, electric boilers, electric heaters, heat pumps (up to 25% substitution), microwave heaters	Vehicles, other industry
	High temperature	Electric heaters, hydrogen heaters	Refining, Ethylene & Ammonia
	Steam	Biomass boilers, hydrogen boilers, electric boilers, heat pumps in limited applications (up to 25% substitution)	Food & Drink, Paper, Chemicals, other industry
Direct heating	Low temperature	Electric heaters, hydrogen heaters	Vehicles, other industry
	High temperature	Biomass and waste combustion (cement sector – up to 80% substitution), hydrogen heaters, electric kilns / furnaces, radio frequency heating, electric plasma gas heaters (up to 25% substitution)	Glass, Ceramics, Cement, other non-metallic minerals
	Reduction processes	Direct reduction of biomass/waste materials (up to 25% substitution) or hydrogen (up to 25% substitution), electric plasma gas heaters (up to 25% substitution)	Iron production

"Low temperature" corresponds to processes requiring temperatures of 30-80°C for indirect heating, and 80-240°C for direct heating. High temperature corresponds to processes requiring temperatures of up to 600°C for indirect heating, and up to 2,000°C for direct heating. Steam at different pressures can meet indirect heating requirements in the 80-240°C range.

Fuel switching – counterfactual technologies used for capex premium calculation and counterfactual lifetime

Processes driven by:	Process type	Counterfactual technology
Indirect heating	Steam	Gas boiler
	High temperature	Gas boiler
	Low temperature	Gas boiler
Direct heating	Primary iron production	Blast furnace, basic oxygen furnace and sinter plant
	High temperature	Gas fired furnace or kiln (as appropriate to the relevant sector) Mixed kiln (40% alternative fuels, 60% coal / pet coke) for cement kilns
	Low temperature	Gas fired furnace

- Note that the same counterfactual costs and lifetimes are used to calculate cost premiums for non gas-driven processes.

Fuel switching – technology capex and opex assumptions

Technology	Reference size (MW)	Marginal capex (/kW)	Marginal opex (/kW/y)
Large Biomass Steam Boiler	50.0	515.00	5.20
Small Biomass Steam Boiler	1.0	515.00	4.90
Direct Biomass Combustion	120.0	62.50	1.25
Biomass Combustion + O2 enrichment	120.0	67.00	1.33
Direct Biomass Reductant	120.0	83.00	1.25
Electric Steam Boiler (small)	4.0	120.00	4.00
Electrode Steam Boiler (large)	50.0	120.00	2.40
Electric Process Heater	4.0	120.00	2.40
Electric Ceramic Tunnel Kilns	20.0	1,000.00	3.34
Electric Infra-Red Heaters	0.006	233.00	4.66
Electric Plasma Gas Heaters	7.0	262.00	2.98
Microwave Heaters	0.100	8,000.00	160.00
OL Heat Pump (MVR)	1.6	300.00	6.00
CL Heat Pump	1.0	450.00	9.00
Electric glass furnace	35.0	193.00	3.34
H2 for Direct Reduction	120.0	232.00	4.64
100% H2 Fuel Boilers	50.0	199.00	3.98
100% H2 Fuel Heaters	35.0	232.00	4.64
H2 fired kiln	10.0	732.00	13.30
Natural gas fired furnace	35.0	193.00	3.86
Natural gas boiler	50.0	166.00	3.32
40 alternative, 60 coal/petcoke fired kiln	120.0	-	2.50
Natural gas fired kiln	120.0	665.00	13.30

Note: A sizing coefficient of 0.6 was used to calculate capex for specific sites

Fuel switching – technology efficiency assumptions

Technology	Efficiency
Large Biomass Steam Boiler	0.9
Small Biomass Steam Boiler	0.9
Direct Biomass Combustion	0.8
Biomass Combustion + O2 enrichment	0.8
Direct Biomass Reductant	0.8
Electric Steam Boiler (small)	1.0
Electrode Steam Boiler (large)	1.0
Electric Process Heater	1.0
Electric Ceramic Tunnel Kilns	1.0
Electric Infra-Red Heaters	1.0
Electric Plasma Gas Heaters	0.9
Microwave Heaters	1.0
OL Heat Pump (MVR)	4.0
CL Heat Pump	4.0
Electric glass furnace	1.0
H2 for Direct Reduction	0.9
100% H2 Fuel Boilers	0.9
100% H2 Fuel Heaters	0.9
H2 fired kiln	0.9
Natural gas fired furnace	0.9
Natural gas boiler	0.9
40 alternative, 60 coal/petcoke fired kiln	0.9
Natural gas fired kiln	0.9

Overview of abatement technologies

Roll-out scenarios

Calculating cost premiums and abatement costs

Technology cost and characteristic assumptions

Fuel cost and emissions assumptions

Fuel switching assumptions – fuel prices and emissions factors

Fuel prices and emissions factors

- **Hydrogen**
  - Suitable for almost all heating applications
  - Price: **4.9 p/kWh (assumed to be almost static to 2070)**
  - Indirect emissions: **11.5 gCO_2/kWh**
- **Biomass**
  - Suitable for indirect heating applications and limited direct heating applications
  - Price: **5 p/kWh (assumed to be static to 2070)**
  - Net emissions (used for cost of abatement calculation): **0 gCO_2/kWh** (based on emissions limit for RHI biomass)
- **Electricity**
  - Suitable for most heating applications
  - Price: (CCS analysis) **11 p/kWh in 2019,** reducing to **8 p/kWh in 2060**[1]
  - Indirect emissions: **196 gCO_2 /kWh in 2019,** reducing to **zero by 2052**

1) The fuel switching spreadsheet assumes a constant electricity price of 8p/kWh after 2050, as the CCC price projections end in 2050