Department
of Energy &
Climate Change

RHI Evidence Report: Direct Application of Renewable Heat

Cost, Performance, and Characteristics of Direct Application of Renewable and Low Carbon Heat in Non-Domestic Processes.

29th October 2014

Prepared for DECC by:

Ricardo-AEA

URN 14D/394

Any enquiries regarding this publication should be sent to us at:
heatstrategypolicycorrespondence@decc.gsi.gov.uk, or

Department of Energy and Climate Change, 3 Whitehall Place, London SW1A.

Contents

Glossary 9

Executive Summary 13

1. Introduction 20

2. Characteristics of Candidate Fuels 23

- 2.1. The Candidate Fuels 23
- 2.2. Gross Calorific Values 25
- 2.3. Flame Temperatures and Luminosity 25
- 2.4. Composition of Combustion products 43
- 2.5. Compatibility with Incumbent Burners 43
- 2.6. Availability of Fuels 44
  - 2.6.1. Biomass 44
  - 2.6.2. Biogas 47
  - 2.6.3. Hydrogen 47
  - 2.6.4. Fuels Made from Waste 47
  - 2.6.5. Syngas 48
  - 2.6.6. Industrial Process Gases 48

3. Characteristics of Glass Sector 49

- 3.1. Glass Sector – Sub-sectors and Direct Heat Consuming Processes 49
  - 3.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat 49
  - 3.1.2. Direct Heat Consuming Processes 50
- 3.2. Glass Sector – Characteristics of Direct Heat Consuming Processes 51
  - 3.2.1. Types of Fuel Used 51
  - 3.2.2. Fuel Costs 52
  - 3.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions 52
  - 3.2.4. Heat Load Factors 53
- 3.3. Types of Burner Used 53
  - 3.3.1. Diffusion Burner 54
  - 3.3.2. Pre-mixed Burners – Nozzle Burners 54
  - 3.3.3. Pre-mixed Burners – Manifold Pre-mix 54
- 3.4. Technical Potential for Candidate Fuel Consumption and Barriers 54

3.4.1. Suitability of Candidate Fuels 54
3.4.2. Technical Barriers to Candidate Fuel Use 55
3.4.3. Technical Potential for Candidate Fuel Use 57
3.4.4. Cost Effective Potential for Candidate Fuel Use 59
4. Characteristics of Iron and Steel Sector 74
4.1. Iron and Steel Sector – Sub-sectors and Direct Heat Consuming Processes 74
4.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat 74
4.1.2. Direct Heat Consuming Processes 75
4.2. Iron and Steel Sector – Characteristics of Direct Heat Consuming Processes 77
4.2.1. Types of Fuel Used 77
4.2.2. Fuel Costs 78
4.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions 78
4.2.4. Heat Load Factors 79
4.3. Types of Burner Used 79
4.4. Technical Potential for Candidate Fuel Consumption and Barriers 80
4.4.1. Suitability of Candidate Fuels 80
4.4.2. Technical Barriers to Candidate Fuel Use 81
4.4.3. Technical Potential for Candidate Fuel Use 81
4.4.4. Cost Effective Potential for Candidate Fuel Use 83
4.5. Basis of Energy Accounting 84
4.6. Comparison with DUKES Data 85
5. Characteristics of Ceramics Sector 86
5.1. Ceramics Sector – Sub-sectors and Direct Heat Consuming Processes 86
5.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat 86
5.1.2. Direct Heat Consuming Processes 87
5.2. Ceramics Sector – Characteristics of Direct Heat Consuming Processes 88
5.2.1. Types of Fuel Used 88
5.2.2. Fuel Costs 88
5.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions 89
5.2.4. Heat Load Factors 89
5.3. Types of Burner Used 90
5.4. Technical Potential for Candidate Fuel Consumption and Barriers 90
5.4.1. Suitability of Candidate Fuels 90
5.4.3. Technical Potential for Candidate Fuel Use 91
5.4.4. Cost Effective Potential for Candidate Fuel Use 92

6. Characteristics of Cement Sector 100
6.1. Cement Sector – Sub-sectors and Direct Heat Consuming Processes 100
6.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat 100
6.1.2. Direct Heat Consuming Processes 100
6.2. Cement Sector – Characteristics of Direct Heat Consuming Processes 101
6.2.1. Types of Fuel Used 101
6.2.2. Fuel Costs 102
6.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions 102
6.2.4. Heat Load Factors 103
6.3. Types of Burner Used 103
6.4. Technical Potential for Candidate Fuel Consumption and Barriers 104
6.4.1. Suitability of Candidate Fuels 104
6.4.2. Technical Barriers to Candidate Fuel Use 104
6.4.3. Technical Potential for Candidate Fuel Use 104
6.4.4. Cost Effective Potential for Candidate Fuel Use 105
7. Characteristics of Food & Drink Sector 112
7.1. Food & Drink Sector – Sub-sectors and Direct Heat Consuming Processes 112
7.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat 112
7.1.2. Direct Heat Consuming Processes 113
7.2. Food & Drink Sector – Characteristics of Direct Heat Consuming Processes 115
7.2.1. Types of Fuel Used 115
7.2.2. Fuel Costs 115
7.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions 116
7.2.4. Heat Load Factors 116
7.3. Types of Burner Used 117
7.4. Technical Potential for Candidate Fuel Consumption and Barriers 117
7.4.1. Suitability of Candidate Fuels 117
8. Characteristics of Oil Refining Sector 124
8.1. Oil Refining Sector – Sub-sectors and Direct Heat Consuming Processes 124
8.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat 124
8.1.2. Direct Heat Consuming Processes 126
8.2. Oil Refining Sector – Characteristics of Direct Heat Consuming Processes 127
8.2.1. Types of Fuel Used 127
8.2.2. Fuel Costs 127
8.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions 128
8.2.4. Heat Load Factors 128

8.3. Types of Burner Used ... 128
8.4. Technical Potential for Candidate Fuel Consumption and Barriers ... 128
  8.4.1. Suitability of Candidate Fuels and Technical Barriers ... 128
  8.4.2. Technical Potential for Candidate Fuel Use ... 129
  8.4.3. Cost Effective Potential for Candidate Fuel Use ... 129
8.5. Comparison with DUKES Data ... 130
9. Characteristics of Chemicals Sector ... 131
9.1. Chemicals Sector – Sub-sectors and Direct Heat Consuming Processes ... 131
  9.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat ... 131
  9.1.2. Direct Heat Consuming Processes ... 133
9.2. Chemicals Sector – Characteristics of Direct Heat Consuming Processes ... 135
  9.2.1. Types of Fuel Used ... 135
  9.2.2. Fuel Costs ... 135
  9.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions ... 136
  9.2.4. Heat Load Factors ... 136
9.3. Types of Burner Used ... 136
9.4. Technical Potential for Candidate Fuel Consumption and Barriers ... 136
  9.4.1. Suitability of Candidate Fuels ... 136
  9.4.2. Technical Barriers to Candidate Fuel Use ... 136
  9.4.3. Technical Potential for Candidate Fuel Use ... 137
  9.4.4. Cost Effective Potential for Candidate Fuel Use ... 137
9.5. Comparison with Dukes Data ... 137
10. Characteristics of Paper & Pulp Sector ... 138
10.1. Paper & Pulp Sector – Sub-sectors and Direct Heat Consuming Processes ... 138
  10.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat ... 138
  10.1.2. Direct Heat Consuming Processes ... 138
10.2. Paper & Pulp Sector – Characteristics of Direct Heat Consuming Processes ... 139
  10.2.1. Types of Fuel Used ... 139
  10.2.2. Fuel Costs ... 140
  10.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions ... 140
  10.2.4. Heat Load Factors ... 141
10.3. Types of Burner Used ... 141
10.4. Technical Potential for Candidate Fuel Consumption and Barriers ... 141
  10.4.1. Suitability of Candidate Fuels ... 141
  10.4.2. Technical Barriers to Candidate Fuel Use ... 141

10.4.3. Technical Potential for Candidate Fuel Use 141
10.4.4. Cost Effective Potential for Candidate Fuel Use 142
11. Monitoring of Direct Heat 147
11.1. Method 1 Measurement of Direct Heat 147
11.1.1. Location of thermocouples 147
11.1.2. Location of flow measurement devices 148
11.1.3. Suitability of flow measurement devices 148
11.1.4. Measurement of composition 148
11.1.5. Measurement of energy input and output 149
11.2. Method 2 Direct Measurement of Fuel Input (Fuel input benchmark method) 150
11.3. Method 3 Direct Measurement of Product Output (Product benchmark method) ... 151
11.4. Protocol 153
11.5. Recommendation 153
11.6. Dual Use Fuels 155
11.7. Measurement Uncertainty Considerations 155
12. Analysis and Conclusions 156
12.1. Extent of Direct Heat Consumption in the Sectors 156
12.2. Technical Potential for Candidate Fuel Consumption 157
12.2.1. Glass, Food and Drink, Ceramics and Paper 157
12.2.2. Cement 158
12.2.3. Iron and Steel 159
12.2.4. Refineries 160
12.2.5. Chemicals 160
12.3. Costs of Candidate Fuel Consumption 160
12.3.1. Glass, Food and Drink, Ceramics and Paper 160
12.3.2. Syngas – biomass 161
12.3.3. Hydrogen 162
12.3.4. Cement 162
12.3.5. Iron and Steel 163
12.4. Cost Effective Potential for Candidate Fuel Consumption 163
12.4.1. Fuel Savings Relative to Counterfactual 163
12.4.2. The Case for Hydrogen 164
12.4.3. CO_{2e} Savings Relative to the Counterfactual 164
12.4.4. Cost Effective Potential of New Technologies 164
12.5. The Case for Support 165
12.6. Non-Technical Barriers to Candidate Fuel Consumption 167

12.7. Avoiding Perverse Incentives 174
12.8. Conclusions 174
12.9. Suggestions for Further Research Required 175
13. Appendix 1 – Gasifier Cost Assumptions 178
14. Appendix 2 – Burner Cost Assumptions 180
15. Appendix 3 – Glass Scenario Assumptions 182
16. Appendix 4 Iron and Steel Scenario Assumptions 188
17. Appendix 5 Ceramics Scenario Assumptions 190
18. Appendix 6 – Cement Scenario Assumptions 195
19. Appendix 7 – Maltings Scenario Assumptions 198
20. Appendix 8 – Paper Scenario Assumptions 203
21. Appendix 9 – Assumptions Regarding Hydrogen CO_{2e} Factors and Process 207
22. Appendix 10 – Summary of Model for Determining the Cost Effective Potential for Candidate Fuel Substitution 209
23. Appendix 11 - Summary of Results of Cost Effective Potential Analysis 214
24. Appendix 12 Fuel Emission Factors and Prices 216
25. Appendix 13 Detail of Biomass Scenarios Presented in Section 2.6.1 222
26. Appendix 14 – Stakeholders Contacted 224

Glossary

AD – Anaerobic Digestion

AEA – AEA Technology

AOD – Argon Oxygen Decarbonisation. A process used to control the composition of molten steel during the production of stainless steel

BAU – Business as Usual (please refer to “Counterfactual” below)

BAT Document – Best Available Technique reference Document

BCC – British Ceramics Confederation

BFG – Blast Furnace Gas. Gas with a calorific value generated as a by-product of the blast furnace process carried out at integrated steelworks

BOS – Basic Oxygen Steelmaking. A process whereby the carbon content of high carbon content pig iron is lowered by blowing oxygen through the molten metal

BROWN – The name given to a scenario in this study for hydrogen whereby the hydrogen is assumed to be produced by Steam Methane Reforming for the entire 30 year period of the appraisal period with no CS applied. (See Section 21)

C&I –Commercial and Industrial

CaO – Calcium Oxide, formed from the calcination of limestone in the cement manufacturing process

Capex – Capital Expenditure. In the context of this study, expenditure on fixed assets such as burners, gasification plant etc.

CCC – Committee on Climate Change

CCL – Climate Change Levy. Tax paid electricity, natural gas, LPG coal and other solid fuels consumed by non-domestic consumers

CCS - Carbon Capture and Storage. A process whereby CO_{2e} emissions from large point sources are captured and then transported to and deposited at storage sites, thereby preventing the CO_{2e} from entering the atmosphere

CHP – Combined Heat and Power. A process whereby the heat generated as a by-product of power (usually electricity) generation is put to a useful purpose. It is used widely within the following sectors examined in this study: Food and Drink, Chemicals, Oil Refineries and Paper

CHPQA – Combined Heat and Power Quality assurance Programme

CIA – Chemical Industries Association

CO_{2e} – Carbon dioxide equivalent

COG – Coke Oven Gas. Gas with a calorific value produced as a by-product of the coal coking process carried out at integrated steelworks

CPI – Confederation of Paper Industries

Counterfactual – The base or business-as-usual case against which the environmental and economic performance of a renewable or low carbon fuel is measured in this study

CV – Calorific Value

DC Arc Vessel – Direct Current Arc Vessel

DECC – Department of Energy and Climate Change

Delivered Energy – Energy in the form in which it is consumed in an industrial process. Delivered energy could be a primary fuel such as coal or natural gas or a secondary form of energy such as electricity or coke

Direct Heat – Heat energy supplied to an industrial process (usually in the form of hot air) and not indirectly via steam or hot water

DR – Discount Rate. The rate at which future costs and benefits are discounted in order to express them as a present value

DUKES – Digest of United Kingdom Energy Statistics

EAF – Electric Arc Furnace – Furnace used for melting steel scrap or directly reduced iron

EPC – Environmental Pollution Control

EUA – European Union Allowance. Confers the right for the holder to emit 1 tonne of CO_{2e}

EU ETS – European Union Emissions Trading System

FDF – Food and Drink Federation

Gate fee – Charge levied on waste received at a waste processing facility

GCV – Gross Calorific Value. Also known as Higher Heating Value. The GCV of a fuel is the energy released upon combustion plus that recovered when all of the combustion products are brought back to their pre-combustion temperature

GJ – Gigajoule (10^9 J)

GREEN - The name given to a scenario in this study for hydrogen whereby the hydrogen is assumed to be produced by electrolysis for the entire 30 year period of the appraisal period. The CO_{2e} attached to hydrogen made in this way is coupled to the CO_{2e} factor for electricity (See Section 21)

GW – Gigawatt

GWh – Gigawatt hour

IPPC – Integrated Pollution Prevention and Control

KaBCA – Kaolin and Ball Clay Association

Ktpa – kilotonnes per annum

$kgCO_{2e}/kWh$ – kilogrammes of carbon dioxide equivalent emitted per kilowatt hour of energy consumed

LHV – Lower Heating Value. The heat available from combustion of a fuel, excluding the heat recoverable from the condensation and cooling of water vapour present in the combustion products

LPG – Liquid Petroleum Gas

MAGB – Maltsters' Association of Great Britain

MBT – Mechanical Biological Treatment. A type of waste process that combines a sorting facility with a form of biological treatment such as composting or anaerobic digestion

MHT – Mechanical Heat Treatment. A type of waste process whereby the sorting stage is followed by thermal treatment. Often called Autoclaving. Similar to MBT but does not include a biological degradation stage such as anaerobic digestion or composting

MJ – Megajoule (10^6 J)

MJ/M^3 – Megajoule per cubic metre

MIXED - The name given to a scenario for hydrogen in this study whereby the hydrogen is assumed to be produced by Steam Methane Reforming for the entire 30 year period of the appraisal period, with the application of some CCS from 2030 onwards (See Section 21)

MPA – Mineral Products Association

MSW – Municipal Solid Waste. The type of waste consisting of everyday items discarded by the public. It covers household waste and household-like commercial and industrial waste (e.g. from offices and hotels)

MW – Megawatt

MWh – Megawatt hour

MWh/tonne – Megawatt hour per tonne of output (a measure of specific energy consumption)

MWth – Megawatt thermal

NO_x – Generic term for the mono oxides of nitrogen (e.g. NO and NO_2) formed from the reaction of oxygen and nitrogen at elevated temperatures during combustion

NPV – Net Present Value (of an investment)

Opex – Operational Expenditure. In the context of this study ongoing expenditure incurred to run the direct heat consuming process, e.g. maintenance costs

PCI – Pulverised Coal Injection. A process whereby pulverised coal is injected into a blast furnace via the tuyeres in order to reduce the consumption of more expensive coke.

PJ – Petajoule (10^{15} J)

Primary energy – Energy in its natural form before it has undergone any transformation into secondary forms of energy which are subsequently consumed in an industrial process. Examples of primary forms of energy are coal and natural gas. Examples of secondary forms of energy are electricity generated from combustion, coke, COG, BFG, BOS gas

RDF – Refuse Derived Fuel – Fuel produced by shredding and dehydrating municipal solid waste (MSW) via a process of MBT. RDF consists largely of the combustible components of MSW such as biodegradable waste and plastic

RHI – Renewable Heat Incentive

SMR – Steam Methane Reforming. An industrial process to produce hydrogen from methane.

SRF – Solid Recovered Fuel. A fuel produced by shredding and dehydrating solid waste via a process such as MBT. SRF is different from RDF in that it is produced to meet a specific quality standard (composition and GCV)

SRM – Steam Reformation of Methane. The main industrial process used for the production of hydrogen

SSI UK– Sahaviriya Steel Industries. A company operating an integrated steelworks at Redcar

Syngas biomass – Syngas produced from the oxygen blown gasification of biomass

Syngas waste – Syngas produced from the oxygen blown gasification of waste such as RDF or SRF

TAD – Through Air Dryer. A type of dryer used in the manufacture of tissue paper.

tCO_{2e} – One tonne of carbon dioxide equivalent

thm – Tonne hot metal. This is the measure of output from a blast furnace

ktoe – kilo-tonne of oil equivalent

UKPIA – United Kingdom Petroleum Industry Association

UKSA - UK Steel Association

WRAP – Waste and Resources Action Programme.

Executive Summary

Introduction

This report sets out the findings of a DECC-funded study to assess the potential to replace fossil fuels with low carbon and renewable fuels in direct industrial heating applications. Industrial processes use heat in a variety of ways. Many sectors use heat to make hot water or steam which is then used in processes. However, others apply heat directly to processes, and this is the subject that is of interest to the current study.

We characterised a range of candidate renewable and low carbon fuels that could be used to generate direct heat in industrial processes. This was based on their physical and economic attributes.

The fuel consumption for heat and direct heat generation was researched and established, or estimated, for eight large heat consuming industrial sectors.

The direct heat consuming processes in the industrial sectors were identified and characterised in terms of their technical compatibility with the candidate fuels.

The cost effectiveness and CO_{2e} saving potential of a range of scenarios for the substitution of incumbent fuels with candidate fuels was investigated. For scenarios where the substitution is not cost effective, we give an indication of the level of subsidy required to make it cost effective.

Non-technical barriers to the implementation of projects to use renewable and low carbon fuels for the generation of direct heat in industry are discussed, and possible support measures suggested.

Candidate methods for determining the quantity of direct heat consumed in industrial processes, derived from renewable and low carbon fuels, were identified. They were then examined in terms of their advantages, disadvantages and practicality of implementation.

Characterising the market and technology outlook

The consumption of fuel for the generation of direct heat in industry is significant. The proportion of fuel of fuel consumed for heat that is consumed for direct heat varies significantly across sectors. Table 1 shows the quantities of fuel consumed for the generation of heat and the generation of direct heat, ranked according to consumption of the latter. The CO_{2e} emissions associated with the generation of direct heat is also provided.

Figure 1 shows the relative consumptions of fuel graphically.

Table 1 The consumption of fuel for all heat, direct heat and associated CO_{2e} emissions (Data provided by the sectors' respective trade associations. Data presented as received)

Industrial Sector	Fuel Consumption for Heat (MWh)	Fuel Consumption for Direct Heat (MWh)	Associated CO_{2e} Emissions for Direct Heat (tCO_{2e})	Year
Iron and Steel	67,921,055[1]	59,316,242[2]	20,958,660	2013
Refineries	59,151,000[3]	40,737,000[4]	10,302,402	2012
Chemicals	60,382,871[5]	41,242,522[6]	Insufficient information on fuel split	2006
Cement	6,842,435	6,842,435	1,646,312	2012
Glass	6,500,000	6,436,716	1,355,101	2012
Food and Drink	31,261,440[7]	4,789,000	889,877	2008
Ceramics	3,970,671	3,886,805	736,834	2012
Lime[8]	*1,885,497*	*1,885,497*	*386,497*	*2012*
Paper	9,900,000	1,338,000	247,811	2012
Asphalt[9]	*1,366,584*	*1,366,584*	*334,589*	*2012*
Total	**249,181,553**[10]	**167,840,801**[10]	**36,858,083**[10]	

---

[1] The fuel for indirect heat includes the double of counting of some energy, due to the consumption of by product gases such as blast furnace gas, coke oven gas and BOS gas for the generation of steam at CHP stations, which is subsequently consumed by steam producing processes. Unlike the case for direct heat, information is not available to allow this double counted energy to be removed. This would require knowledge of the quantity of by-product gas consumed in the CHP and the quantities of power and steam generated by the CHP. This information is not available to the authors

[2] Double counting of energy removed where appropriate. See section 4.5

[3] Includes fuel for power generation at refineries with embedded CHP

[4] Fuel for direct heat not supplied by sector. Fuel for direct heat estimated (see 8.1.1)

[5] Includes fuel for power generation but excludes fuel associated with steam imported from 3rd parties.

[6] Fuel for direct heat not supplied by sector. Fuel for direct heat estimated (see 9.1.1)

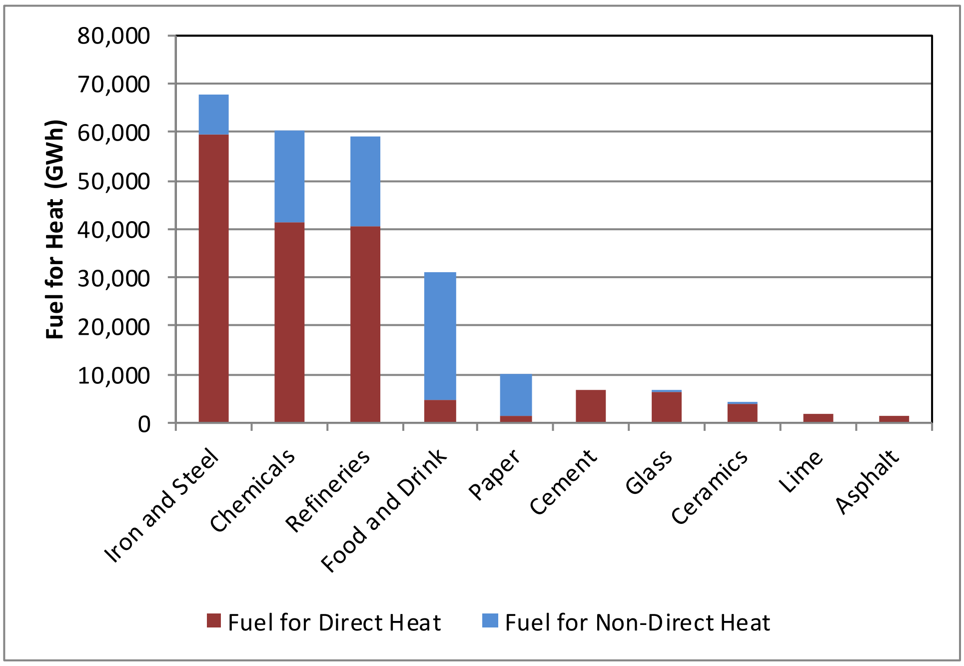
[7] Supplied by Food and Drink federation, but taken from Energy Consumption in the UK

[8] Lime is not a sector included in the project specification, but is not an insignificant user of direct heat. Data added to put relative importance of sectors into context.

[9] Asphalt is not a sector included in the project specification, but is not an insignificant user of direct heat. Data added to put relative importance of sectors into context.

[10] Note this total is for different years across the sectors and so should be considered as indicative.

Figure 1 Fuel for total heat, fuel for direct heat and fuel for non-direct heat for sectors in Table 1



In order to be compatible with existing processes and products, renewable and low carbon fuels in **Glass** and **Paper** should be clean burning and be gaseous. This is also the case in a very large proportion of the **Ceramics** and **Food and Drink** sectors. This means that relevant candidate fuels for these sectors are syngas, hydrogen, biogas and (to a limited extent) pulverised biomass.

Literature review indicates the future availability of only very small amounts of biogas for direct heat applications in industry. This finding, limited technical potential for pulverised biomass consumption in these sectors, and a lack of cost data on pulverised biomass burners, means that only the cost effectiveness of syngas and hydrogen has been investigated for these sectors.

Solid fuels constitute the overwhelming majority of fuel consumption in the **Cement** sector. This indicates that the solid renewable and low carbon fuels of waste wood chip and Solid Recovered Fuel (SRF) are likely to be the most suitable for this sector. The cost effectiveness of these fuel substitutions was investigated.

The by-product gases of the **Iron and Steel** sector are not renewable as they are ultimately derived from mineral coal. However, the generation of these by-product gases is unavoidable and their consumption displaces the importation and consumption of other fuels. Where there is demand for heat and power on the site, there is already a high degree of utilisation of these by-product gases. Blast furnaces consume about 80% of all the fuel for direct heat in the Iron and Steel sector. The overwhelming majority of fuel consumed in the blast furnace is in the form of the solid fuels of coke and coal. The cost effective potential for some of this fuel to be substituted by biomass charcoal was investigated.

Estimates of the fuel consumed for direct heat generation in the **Refineries** sector indicate that a very high proportion of fuel consumed for the generation of direct heat are by-product fuels.

These are from refinery gas and petroleum coke, which would have to be combusted either at the refinery or at another place. Consequently, the proportion of fuel consumption at refineries that could be substituted with renewable or low carbon fuels, with a resulting reduction in CO_{2e} emissions, is small.

There was insufficient granularity of data available regarding the consumption of direct heat in the **Chemicals** sector to allow cost effective analysis to be undertaken. However, data from the sector indicates that a large proportion of fuel consumed (~40%) is in the form of manufactured fuel, which is a by-product of the chemical processes carried out. These fuels would either continue to be burned to generate heat for chemical processes, flared or burned in another place, resulting in the same CO_{2e} emissions. As such, the potential to substitute these manufactured fuels with renewable and low carbon fuels is considered limited.

For sectors susceptible to syngas and hydrogen substitution, there is ongoing uncertainty about the extent to which these fuels can be utilised in existing burner systems. Consequently, it has been assumed in the analysis that full displacement of burner systems is necessary. There is also uncertainty about the extent to which these fuels can be substituted without triggering the need for wider process changes, which would incur significant additional costs. Where is concern about the ability of a process to tolerate a 100% substitution with syngas or hydrogen without wider process change being required, lower levels of substitution are assumed, so as to avoid triggering wider process change and significant additional costs. This has been the approach adopted for **Glass Melting** and **Ceramic Firing**. For other processes where syngas and hydrogen are candidate fuels, 100% substitution is assumed.

Data from burner suppliers indicate the relative costs of natural gas, syngas, hydrogen and biogas burners. These are provided in Appendix 2.

The consumption of syngas is assumed to require the presence on site of a gasifier of waste or biomass. Data from the literature indicates a Capex of £1.7m/MWth of gas output capacity for Advanced Thermal Treatment of Municipal Solid Waste. Where applicable, this cost has been used in the analysis relating to the gasification of waste and the gasification of biomass. Key to the operation of these gasifiers is the availability of waste and biomass. In respect of waste, receiving waste for gasification is assumed, in some instances, to constitute revenue for the receiving party, deriving from gate fee received. There is uncertainty relating to the gate fee that the operator of a gasifier would receive, especially as the market for waste develops. Consequently, a range of gate fees has been analysed: -£40/tonne, £0/tonne and £40/tonne, where -£40/tonne represents the operator of the gasifier paying to receive the waste and £40/tonne represents the operator receiving a payment of £40/tonne.

There is also significant uncertainty regarding the price that industrial users of hydrogen would be exposed to, and the resultant CO_{2e} emissions that would be emitted – see below.

Renewable and carbon saving credentials

The only sector where renewable fuels are currently used for the generation of direct heat is in the **Cement** sector, where a wide range of renewable and low carbon fuels are combusted.

In each case, the counterfactual considered was the current mix of fuels used, or a close approximation to it where there is a large and diverse fuel mix and simplification of the analysis requires an approximation.

The consumption of syngas generated from the gasification of RDF is a source of CO_{2e} savings at a cost in the range -£8/tonne CO_{2e} to +£640/tonne CO_{2e}. However, these extremes are not representative and are associated with either very low load factors of heat generating capacity and, therefore, syngas-waste generating capacity, or a relatively expensive business as usual case, due to the use of expensive electricity. In the majority of cases, where natural gas is the only fuel being displaced, the cost is in the range +£35/tonne CO_{2e} to +£99/tonne CO_{2e}, depending upon the gate fee assumption made. The consumption of syngas generated from the gasification of waste wood chip is a source of CO_{2e} savings at a positive cost in the range +£24 to +£61/tCO_{2e} depending on the incumbent fuel being displaced, with the highest cost found for natural gas displacement.

With the exception of one scenario investigated (the most unfavourable: gate fee = -£40/tonne and highest and most capital intensive substitution level), the consumption of Solid Recovered Fuel (SRF) directly in cement kilns is a source of CO_{2e} savings at negative cost across a range of substitution levels above those currently used in the sector. The consumption of biomass (waste wood chip) directly in cement kilns is a source of CO_{2e} savings but at a positive cost in the range (£11-46/tCO_{2e}) against the counterfactual. The cost of additional biomass consumption relative to the counterfactual is sensitive to the gate fee assumption because SRF is currently burned in the counterfactual.

The consumption of biomass charcoal in the **Iron and Steel** sector is a source of CO_{2e} savings, but at a cost in the region of £100/tCO_{2e}.

As mentioned above, there is uncertainty regarding the extent to which alternative methods of hydrogen production will be used in the future and the CO_{2e} intensity of these methods. Consequently, to reflect this uncertainty, three different scenarios for hydrogen production are investigated and these are set out in detail in Appendix 9 – Assumptions Regarding Hydrogen CO_{2e} Factors and Process. However, for all processes where hydrogen is considered a candidate fuel, its adoption results in an increase in CO_{2e} emissions, relative to the business as usual case, over a 30 year assessment period. The application of Carbon Capture and Storage (CCS) on Steam Methane Reforming (SMR) or decarbonisation of the electricity grid would have to be brought forward in time if hydrogen were to represent a means of CO_{2e} reduction in the industrial processes considered. In light of this finding, the cost effectiveness of hydrogen substitution has not been investigated further.

Market drivers and barriers to deployment

1. The following non-technical barriers to deployment have been identified following communications with sector associations:
    - The reliability of technology using candidate fuels
    - Ability of the site to cope with practicality of fuel deliveries (e.g. increased traffic movements)
    - Security of supply of the fuel
    - Availability of the fuel

- Sustainability of the fuel
- Price
- Changes in the calorific value of the fuel over time
- Certainty of government policy
- Negative public perception of the use of waste as a source of energy
- Anxiety regarding negotiation of contracts for supply of candidate fuels
- Anxiety regarding technical challenges of operation of new plant consuming candidate fuels
- Anxiety over applicability of a candidate fuel for a particular site
- How the fuel will be treated from the point of view of CO_{2e} emissions
- Alternative use of fuel as a feedstock.

These barriers are considered further in Section 12.6 Non-Technical Barriers to Candidate Fuel Consumption, including possible methods of support for overcoming them.

Conclusions

For the scenarios explored regarding the production of hydrogen, we conclude there is no CO_{2e} reduction potential relative to the counterfactual over the 30 year assessment period.

From the analysis, and for the assumptions made regarding the gate fee, we conclude that financial support for the consumption of syngas from the gasification of waste could be an important part of stimulating an increased use of this fuel. However, this conclusion is sensitive to gate fee assumptions.

From the analysis conducted we conclude that, on the surface, financial support for the increased use of SRF directly as a solid fuel in cement kilns is not a necessary part of encouraging the increased use of this fuel in this application. However, the current and future availability of this fuel to cement operators should be looked at further to ensure that the waste that is available is channelled towards the end application with the most beneficial environmental impact. In deciding which applications would have the most beneficial environmental impact, considerations should be given to whether an industrial process has other decarbonisation options open to it, the relative costs of these other options and the quantity of CO_{2e} savings that might result. These considerations will also have to be made with an eye to what the market for waste might be in the future. Incentives could play a role in helping to channel waste towards applications where its consumption would offer the best overall environmental outcome.

From the analysis conducted we conclude that financial support for the consumption of syngas from the gasification of biomass could be an important part of stimulating increased use of this fuel. This is also the case for biomass consumed as a solid fuel.

We conclude that there are a range of non-technical and non-financial barriers to the uptake of the candidate fuels, which should be looked at further.

The method for determining the quantity of renewable heat consumed in a direct heat consuming process likely to be practicable across the largest number of processes involves the direct metering of the quantity of heat leaving the process and the quantity of all fuel and renewable fuel entering the process before combustion. This method would not fit within the current legal framework of the RHI, which requires direct measurement of heat. This method, instead, utilises a direct measurement of the chemical energy within the fuel input to the process and the quantity of heat leaving the process.

Under the current RHI Regulations, not all of the changes required to the processes examined in this study to allow them to burn the candidate fuels would be considered an action trigging an incentive payment. This is because they do not always involve the putting in of new installations. In spite of this, there is still a cost gap between burning the candidate fuel and carrying out business as usual, which could be overcome with an incentive payment. This implies that if the RHI were to be used to incentivise the use of candidate fuels in these direct heat consuming industrial processes, amendments to the RHI Regulations would be required.

This study has relied heavily on evidence and opinions gathered from the industry sectors and equipment manufacturers (burner and gasifier manufacturers). This was necessary as the required evidence tends only to reside with these stakeholders. Industry sectors and equipment suppliers have an obvious stake in the findings of this study and could have an interest in overestimating costs and barriers. This is a potential source of bias which should be kept in mind when interpreting the results of this study.

1. Introduction

This is the final report of a study undertaken to gather evidence related to the technical and economic aspects of the consumption of direct heat, in eight energy intensive industrial sectors. In this context, direct heat is heat supplied directly to a process (usually, but not always, in the form of combustion products) and not via steam or hot water. The industrial sectors examined are:

- Iron and Steel
- Refineries
- Chemicals
- Cement
- Glass
- Food and Drink
- Ceramics
- Paper

The study sets out to characterise a range of renewable and low carbon fuels (candidate fuels) that might be used within the direct heat consuming industrial processes of the above sectors, thereby reducing their CO_{2e} emissions. Characterising the candidate fuels in this way allows the technical potential for these candidate fuels to displace the fuels currently used (incumbent fuels) to be understood. The candidate fuels examined are:

- Biogas
- Biomass
- Syngas
- Fuels derived from waste
- Hydrogen
- Industrial process gases.

The study identifies which processes consume direct heat in the above sectors and establishes which fuels are currently used to generate this direct heat. It examines which candidate fuels have the technical potential to displace the incumbent fuels, and the CO_{2e} savings that might accrue from such a substitution. This establishes the technical potential for candidate fuel substitution.

Having established the technical potential for candidate fuel substitution, the cost effectiveness of this substitution is evaluated using a cost model specifically developed for the purpose. It identifies whether the candidate fuel substitution is cheaper or more expensive than the counterfactual (status quo). Where the substitution is found to be more expensive than the counterfactual, the model determines the level at which subsidies might have to be set in order for the candidate fuel to compete with the status quo. These subsidies are expressed per unit of candidate fuel consumed.

Non-technical barriers to these substitutions are also identified and characterised according to the severity with which they affect each of the sectors under consideration. Potential support measures to overcome these barriers are also outlined. Perverse incentives that might arise from the presence of a subsidy for renewable direct heat are considered, and suggestions are given for how these might be addressed.

The study also examines how the quantity of direct heat derived from the candidate fuels might be determined, so that any subsidy payment attached to the candidate fuel can be appropriately and accurately determined.

The report is structured as follows:

Chapter 2 characterises a number of candidate fuels that might be used as replacements for the incumbent fuels used to generate direct heat in the industry sectors under consideration

Chapters 3-10 characterise each of the eight industry sectors of interest to this study. This characterisation is along the following axes:

- Identification of the sub-sectors and the direct heat consuming processes
- Quantification of the fuel used to generate all heat and the fuel used to generate direct heat
- Characterisation of the direct heat consuming processes in terms total fuel, types of fuel used, temperature requirements of the process and compositional or chemical requirements of the hot air supplying direct heat
- The typical fuel costs experienced by operators of direct heat consuming processes
- The specific energy consumption and CO_{2e} emissions for each direct heat consuming process
- The heat load factors of each direct heat consuming process
- Technical barriers to the consumption of suitable candidate fuels
- Technical potential for consumption of suitable candidate fuels
- Cost effective potential for consumption of suitable candidate fuels. The cost effective potential is presented in tabular form, both in each sector's chapter and aggregated with the results from all of the other sectors in Appendix 11 – Summary of Results of Cost Effective Potential Analysis.

Chapter 11 considers the strengths and weaknesses of three methods of measuring/deducing the quantity of direct heat and discusses their practicality of implementation. It recommends a standard approach likely to be practicable across the largest number of processes.

Chapter 12 analyses and discusses in further depth the findings of the preceding Chapters and considers the case for support, non-technical barriers to the consumption of renewable and low carbon fuels, how perverse incentives might arise if a subsidy were to be paid against the consumption of direct heat from renewable sources, and how these perverse incentives might be addressed. It also considers possible support mechanisms to overcome non-technical barriers.

The Appendices set out important assumptions underpinning the analysis and list stakeholders contacted, as follows:

Appendix 1 sets out the assumptions and data sources relating to gasifier costs.

Appendix 2 sets out assumptions and data relating to capital costs for natural gas, syngas, hydrogen and biogas burners.

Appendix 3-8 set out in detail the assumptions underpinning the cost effective potential derived for the Flat Glass sub-sector, Iron and Steel, Ceramics, Cement, Maltings sub-sector of the Food and Drink main sector and Paper sectors.

Appendix 9 sets out the assumptions relating to hydrogen for establishing its CO_{2e} intensity.

Appendix 10 provides a summary of how the model for determining the cost effective potential for candidate fuel substitution works.

Appendix 11 presents in tabular form a summary of the results of the cost effective potential modelling.

Appendix 12 sets out the CO_{2e} factors and prices used for each of the fuels relevant to the analysis and the sources of these values.

Appendix 13 presents details of the scenarios relating to the availability of biomass presented in Section 2.6.1.

Appendix 14 provides a list of stakeholders contacted during this work.

2. Characteristics of Candidate Fuels

2.1. The Candidate Fuels

The candidate fuels being investigated in this study, which may represent zero or low carbon alternatives to incumbent fuels, include:

- **Biomass** – In general terms, biomass may be thought of as all non-fossil material of biological origin, including vegetable matter and animal biomass. In this study, in order to distinguish biomass clearly from the other candidate fuels (and other biogenic material which may serve as a precursor to the other candidate fuels) and to concentrate on those biomass fuels likely to be available to industry in significant quantities for the generation of direct heat, we consider biomass to be the following solid fuels: virgin wood pellets, virgin wood chips and Grade A[11] waste wood chip[12]. Biomass would be made available for consumption by industry via the delivery of it to site by road or rail transport. The properties of biomass are considered in more detail in Table 2 below.
- **Biogas** – In this study biogas is considered to be the gas produced by an anaerobic digester, whereby a variety of vegetable and animal substances are transformed to methane. Biogas produced in this way will be a mixture of methane and carbon dioxide. Biogas could be made available for consumption by industry either through the existing natural gas grid, or via local generation in anaerobic digesters. The properties of biogas are considered in more detail in Table 2 below.
- **Hydrogen** – Hydrogen as a fuel is produced by three main primary routes: (1) Steam Reformation of Methane (SRM), (2) electrolysis of water, or (3) as a by-product of industrial processes. An example of the last is the generation of hydrogen during the electrolysis of brine to create caustic soda and chlorine gas, used in the chemical industry. A hydrogen grid does not exist and, in the absence of this, hydrogen would have to be either generated locally to the point of use via one of the afore-mentioned routes or generated remotely and transported to the point of use by road or rail transport. The properties of hydrogen are considered in more detail in Table 2. The method used to produce hydrogen will determine the CO_{2e} factor attached to it. If it is produced by the electrolysis of water then the relevant CO_{2e} factor will be determined by the CO_{2e} factor of the electricity used to generate it and the efficiency of the electrolysis process. If this electricity is sourced from the grid, then there would be a CO_{2e} factor attached to the hydrogen until the grid is completely decarbonised. If the electricity comes from a known renewable source, then hydrogen created through electrolysis using that electricity could be considered renewable. However, there is a policy question about providing an incentive twice for essentially the same energy, i.e. if the renewable electricity receives a payment and heat generated through the combustion of the hydrogen created using the renewable electricity also receives an RHI payment. Hydrogen produced from SRM

---

[11] Grade A waste wood chip is derived from waste wood not contaminate by paint, solvents or glues, as might be the case for waste wood recovered from furniture, demolition etc.

[12] Straws and grasses are not considered here on the grounds that the energy density is too low to be used by industry without significant storage issues arising.

would also have a CO_{2e} factor associated with it unless the CO_{2e} by-product of SRM was captured. This is considered further under industrial process gases below.

- **Fuels made from waste** - This covers a wide range of materials. In this study, in order to manage scope and to consider the waste fuels that could be made available to industry in relevant quantities, and with suitable energy densities such that storage is not an issue, the following waste fuels are considered: Grade B and C waste wood chip[13] and Solid Recovered Fuel (SRF)[14].
- **Syngas** – This is produced either by pyrolysis, indirect gasification or oxygen blown gasification of solid waste or biomass. Syngas is distinct from producer gas, which is produced by air blown gasification of solid waste or biomass. Syngas has a higher calorific value than producer gas, owing to the absence of nitrogen, which is present in producer gas. The properties of both syngas and producer gas are considered in more detail in**Error! Reference source not found.** Syngas produced by the gasification of waste will have a CO_{2e} factor attached to it, unless the waste is entirely biogenic in origin. If a whole lifecycle approach is taken to accounting for carbon, and that approach attaches a non-zero CO_{2e} factor to biomass, then syngas created from the gasification of biomass will also have a non-zero CO_{2e} factor. In this study we attach non-zero CO_{2e} factors to syngas from both waste gasification and biomass gasification, on the basis that SRF and biomass waste wood will have non-zero lifecycle CO_{2e} factors.
- **Industrial process gases** - These are gases with a calorific value, arising from the industrial processes. Salient examples of these are: Coke Oven Gas (COG), Blast Furnace Gas (BFG) and Basic Oxygen Steelmaking (BOS) Gas, in the Iron and Steel sectors; refinery gas which does not have a value as a feedstock for the production of saleable refinery products in the Oil Refining sector; and hydrogen in the Chemicals sector. Currently, none of the industrial process gases arising in the Iron and Steel sector (COG, BFG and BOS) can be regarded as renewable. This is because the carbon in these gases ultimately comes from coal. COG is a by-product of the coke ovens which gasify coal to create coke. BFG is a by-product of the consumption of coke in the blast furnace, with the coke made from coal. BOS gas contains carbon monoxide from the partial oxidation of carbon in liquid iron through blowing oxygen through liquid iron. The carbon in the liquid iron comes from the coke fed to the blast furnace which, in turn, came from coal. Hydrogen and refinery gas created as a by-product in Oil Refining will normally have come from a mineral petroleum product which, unless the associated carbon is captured in the process during which the hydrogen is created, will mean that the hydrogen cannot be regarded as carbon neutral. A source of hydrogen in the Chemicals sector is the electrolysis brine in the chlor alkali process. The CO_{2e} attached to hydrogen so created will depend upon the CO_{2e} attached to the electricity used in the electrolysis and the efficiency of the electrolysis process. If that electricity comes from the grid, then there will be CO_{2e} attached to that hydrogen.

With the exception of industrial process gases, which are only available at specific sites generating them, Table 2 summarises the properties of the above candidate fuels. The sections below explain the issues associated with using these fuels in more detail.

---

[13] Grade B waste wood chip would be recovered from sources such as furniture and demolition, while Grade C waste wood chip would be contaminated waste wood from sources such as chipboard and MDF.

[14] Fuels such as Municipal Solid Waste (MSW) are not considered here as they are considered too wet and of too variable calorific value for industry to want to use.

2.2. Gross Calorific Values

With the exception of hydrogen, which, as an elemental gas, has a fixed Gross Calorific Value (GCV), the GCV of the candidate fuels as burned depends on the composition of the biomass starting point and the nature of any pre-treatment.

For solid biomass fuels such as wood, SRF, crop and food processing residues that are burned in their original form, water content is the most important factor determining the GCV.

Gaseous fuels derived from solid biomass such as producer gas or syngas, have a GCV which depends on the chemical process used in their manufacture and the composition of the material being gasified. Those processes using air as an oxidant will have substantial nitrogen dilution of the product. Those using heat in the absence of air, or using pure oxygen as an oxidant, have no dilutant and consequently a higher calorific value.

Pyrolysis liquids are produced by the rapid heating of dry biomass. This causes the biomass to decompose into a vapour of oxygenated organic molecules. Condensing this vapour results in the production of pyrolysis liquid. Typically, this will have a GCV of 15 – 20 GJ/tonne, similar to the biomass from which it was derived.

Feedstocks derived from residual waste will contain oil derived plastics, which will increase the GCV of gaseous and liquid fuels derived from them. This has implications for the proportion of the energy content that may be considered renewable, however.

2.3. Flame Temperatures and Luminosity

Flames are formed when a gaseous, liquid or powdered fuel is burned in an intimate mixture with air. High temperatures are developed and radiation can play an important part in heat transfer. The ability of a flame to radiate heat is described by its luminosity. The luminosity of gas and oil flames is caused by the presence of suspended carbon particles in the flame gases. These suspended particles are created by the pyrolytic decomposition of carbon compounds in the fuel, which occurs when the fuel gas stream gets hot enough for this to happen, but prior to access to combustion air. Where the fuel and air are pre-mixed, there is less opportunity for this breakdown of the fuel to occur prior to combustion. This is why diffusion flames are more luminous than the flames emerging from pre-mixed burners and in the case of the latter, convection will play a greater role in the transfer of heat.

From this, it can be appreciated that the luminosity that a flame can achieve is substantially determined by the carbon content of the fuel. This is why a hydrogen flame has a lower luminosity than a natural gas flame, which in turn has a lower luminosity than an oil flame However, some radiation, but of a lesser amount, does emerge from tri-atomic gases in the flame such as CO_{2e} and H_2O which are present for a wide range of fuels.

Gas and liquid fuels burning as a flame dominate the industrial high temperature heating market, and equipment has been developed that uses the radiation component of the flame to maximum advantage (although convection is an important mechanism of heat transfer in many applications using less luminous flames).

To replace gas or liquid successfully in these applications, biomass must first be converted to a gas or liquid so that a stable flame can be formed in the equipment. The maximum achievable flame temperature will depend on the composition of the gas. Very high temperatures, such as those required in specialist ceramic manufacture, require a gas with high GCV and high flame temperatures. It is possible to burn pulverised wood pellet fuel and torrified[15] biomass as a

---

[15] Torrified wood is wood that has been roasted at a temperature of about 300°C in a low oxygen environment. The result is a product with all moisture and low energy volatiles removed, thereby possessing a higher energy density than the original wood. The product is also highly friable (making it easy to be broken up into a fine powder) and is

flame, but little work has been done outside of utility boiler applications. In any case, the use of pulverised wood pellet or torrified biomass as a fuel for a flame would inevitably lead to unburned or partially burned particulate matter coming into contact with the product. This would preclude the use of such a fuel for the direct application of heat in specific applications such as glass melting, tissue drying and in the food and drink sector, where such incorporation of particulate matter in the product cannot be tolerated.

Solid biomass in lump or chip form must be burned on a grate arrangement where air typically passes through a bed of burning material. Further air is added above the bed and the process is heated by heat exchange with total flow of flue gas. Normally, the air flows are controlled to maintain the combustion temperature below that at which any ash in the fuel melts and to prevent physical damage to the grate. However, in some applications ash melting may be tolerated, such as in the production of cement clinker, where the ash is incorporated in the final clinker product. In practice, this otherwise reduces the potential to processes that can operate with a flow of hot gas below 800°C and a reduced radiation component. Typically this would be dryers, and other low temperature processes.

---

resistant to water. Torrified wood therefore has advantages over ordinary wood in terms of costs of shipping per unit of energy shipped and storage in the un-ground state.

Table 2 Main Properties and Characteristics of Renewable and Low Carbon Fuels

Fuel	Description	Appropriate scale	LHV	Ref	Contamination that might impact on the process	Max Flame temperature compared with fossil fuel comparison. (Based on 15% excess air and 200°C preheat. Ref 7)	Change to burner	Fossil fuel comparison
Producer gas from wood or waste raw	Low calorific value gas produced by air blown gasification. Fixed bed gas producers used below 15MW fluidised bed units above. Feedstock is any solid biomass material. The contaminants will reflect the source however. Materials extracted from MSW and C & I streams will contain chlorine. Crop residues may contain high levels of sodium and potassium salts as aerosols or vapour.	0.5MW upwards. No upper limit	4 – 6 MJ/M3	1,8, 13	May contain high levels of dust and acidic tar.	Substantially lower. 1728 v 1909°C at 15% excess air	Replace burner assembly and gas booster to cope with 6x higher fuel volume. Rebalance combustion air.	Natural gas or oil

Fuel	**Description**	**Appropriate scale**	**LHV**	**Ref**	**Contamination that might impact on the process**	**Max Flame temperature compared with fossil fuel comparison. (Based on 15% excess air and 200°C preheat. Ref 7)**	**Change to burner**	**Fossil fuel comparison**
Producer gas cleaned	Producer gas that has had the tars and dust removed by scrubbing and hot filtration. Cleaning has substantial impact on capex, circa 100%. Gas is generally treated with air and steam at high temperature to reduce tars, filtered to remove dust and further cleaned by liquid scrubbing to further remove contamination.	0.5MW upwards. No upper limit	4 -6 MJ/M3	1, 7,8, 13	Potential contamination by tars and dust if system fails.	Substantially lower. 1728 v 1909°C at 15% excess air	Replace burner assembly and gas booster to cope with 6x higher fuel volume. Rebalance combustion air.	Natural gas or oil

Note (1): The Max Flame Temperature is quoted for a particular level of excess air (15%) and air pre-heat (200°C). As well as the calorific value of a fuel, flame temperature for a particular fuel will depend upon the quantity of air used to support combustion and the temperature of this air. These conditions are selected to be broadly representative of actual combustion conditions utilised, but actual combustion conditions will vary depending upon application. For example, regenerative burners will use combustion air pre-heated to higher temperatures.

Note (2): The Fossil Comparison refers to the fossil fuel most likely to be being replaced by the incumbent fuel under consideration. Therefore, modifications mentioned under the Change to Burner column are modifications required to enable the burner to burn the candidate fuel rather than the Fossil Comparison.

Fuel	Description	Appropriate scale	LHV	Ref	Contamination that might impact on the process	Max Flame temperature compared with fossil fuel comparison. (Based on 15% excess air and 200°C preheat. Ref 7)	Change to burner	Fossil comparison
Syngas (Medium CV gas from waste or wood)	Gas derived from the pyrolysis, indirect gasification or oxygen blown gasification of solid waste or other biomass. Feedstock is any solid biomass material. The contaminants will reflect the source however. Materials extracted from MSW and C & I streams will contain chlorine, mercury, other heavy metals and alkali salts	0.5MW upwards. No upper limit	12- 29 MJ/M3, depending on process and feedstock	9	May contain high levels of dust, acidic tar and sodium or potassium salts as aerosols or vapour.	Equivalent temperature.	Major modification to existing burner assembly with new gas booster, burner nozzles and seals. Higher gas volume required	Natural gas or oil
Syngas cleaned (Medium CV gas from waste or wood cleaned)	Gas derived from the pyrolysis or oxygen blown gasification of solid waste or other biomass. As with producer gas, clean gas is produced by removing contaminants by filtration and scrubbing.	0.5MW upwards. No upper limit	12- 29 MJ/M3, depending on process and feedstock	9,7	Potential contamination by tars and dust if system fails.	Equivalent temperature. Higher gas volume	Major modification to existing burner assembly with new gas booster, burner nozzles and seals. Higher gas volume required.	Natural gas or oil

Note (3): The 30 MW capacity limit is on a thermal basis, and is based on typical limitations of: feedstock availability, physical footprint that can be tolerated at an industrial site, and the availability of an informal disposal route for the digestate (e.g. a farmer’s field). An industrial site burning biogas at a rate greater than 30 MWth would typically have to import the biogas compressed. Such gas would have been produced at large anaerobic digester installations, which may find cleaning-up and injecting the biogas into the gas grid a much more commercially sensible option.

Note (4) Electricity is considered a reference fuel for hydrogen, as hydrogen is extremely clean burning (combustion products are only water) and electricity is used in applications where the heating environment must be extremely clean.

Fuel	Description	Appropriate scale	LHV	Ref	Contamination that might impact on the process	Max Flame temperature compared with fossil fuel comparison. (Based on 15% excess air and 200°C preheat. Ref 7)	Change to burner	Fossil fuel comparison
Biogas Raw	Product gas directly from an anaerobic digester. Heat application and anaerobic digester need to be co-located. AD plant are substantial waste management installations with a large investment cost. Typically they will be located adjacent to food industry sites, water treatment works or municipal waste handling stations. Current heat applications will tend to reflect this.	Upper limit governed by size of digester. Max 30MW. No minimum.	23MJ/M3	2	30 – 40% carbon dioxide. 1% hydrogen sulphide. Siloxanes other acid gas depending on feedstock. Can foul heat transfer surfaces	Slightly lower. 1780 v 1909°C at 15% excess air	Major modification to existing burner assembly with new gas booster, burner nozzles and seals	Natural gas or oil
Biogas cleaned	Biogas that has had water and acid gas components removed. This is normally achieved by a simple water wash with potentially an alkaline additive. There is interest in	Upper limit governed by size of digester. Say max 30MW unless gas is transported from elsewhere. No minimum.	23MJ/M3	2	30 – 40% carbon dioxide. Trace of hydrogen sulphide. No impacts	Slightly lower. 1780 v 1909°C at 15% excess air	Major modification to existing burner assembly with new gas booster, burner nozzles and seals	Natural gas or oil

Fuel	Description	Appropriate scale	LHV	Ref	Contamination that might impact on the process	Max Flame temperature compared with fossil fuel comparison. (Based on 15% excess air and 200°C preheat. Ref 7)	Change to burner	Fossil fuel comparison
	transporting compressed and liquefied gas to remote applications or to centralised processing.							

Note (5) Minor modifications to oil burners to allow the burning of bioliquids mainly relate to the difference between viscosities of bioliquids and mineral oils.

Fuel	Description	Appropriate scale	LHV	Ref	Contamination that might impact on the process	Max Flame temperature compared with fossil fuel comparison. (Based on 15% excess air and 200°C preheat. Ref 7)	Change to burner	Fossil comparison
Biogas upgraded (Biomethane)	Cleaned biogas that has had carbon dioxide removed. CO_{2e} is removed by washing with pressurised water or proprietary amine solution. Alternatively a semi permeable membrane system can be used. Typically the product is 95% plus methane and can replace natural gas in all applications. There is substantial competition for the resource from operators injecting into the transmission and distribution networks with RHI support. There is interest in transporting compressed and liquefied gas to remote applications.	Upper limit governed by size of digester. Max 30MW unless gas is transported from elsewhere. No minimum.	39MJ/M3	2	None. Can be used as natural gas.	No change. 1909°C at 15% excess air	No change	Natural gas

Fuel	Description	Appropriate scale	LHV	Ref	Contamination that might impact on the process	Max Flame temperature compared with fossil fuel comparison. (Based on 15% excess air and 200°C preheat. Ref 7)	Change to burner	Fossil comparison
Hydrogen	Pure gas manufactured by a) steam reforming of natural gas. b) Electrolysis of water Currently no infrastructure for supply as a fuel Storage and safety issues	No limits	10.22 MJ/M3		None.	Much higher 2123ºC at 15% excess air.	Replace due to exceptionally high flame speed which will require new bespoke design. Safety implications of hydrogen usage.	Natural gas, electricity

Note (6): The reference fuel for ethanol is natural gas and electricity, and not kerosene or other mineral oils, as ethanol burns very cleanly and would be displacing applications where the heating environment must be very clean. The conventional alternatives in such applications would be natural gas or electricity.

Note (7): Flame speed is measured by the Weaver Flame Speed Factor. Flame speed is a function of the proportion of hydrogen contained within the fuel, with higher proportions of hydrogen in the fuel leading to higher flame speeds. Hydrogen has a Weaver Flame Speed Factor of 100, while methane (Natural Gas) has a factor of 14[16]. It should be noted that actual flame speeds quoted in the literature can vary significantly for the same fuel, owing to differences in experiment.

---

[16] Technical Data on Fuel, J. W. Rose and J. R. Cooper 1977 p. 267.

Fuel	Description	Appropriate scale	LHV	Ref	Contamination that might impact on the process	Max Flame temperature compared with fossil fuel comparison. (Based on 15% excess air and 200°C preheat. Ref 7)	Change to burner	Fossil comparison
Vegetable oils	Oils extracted from agricultural products such as palm, oil seeds etc. Substantial sustainability issues with consequent reputational risk for users.	No limits	35 GJ/tonne	4	None.	No change	Minor modifications to atomiser, fuel preheat and elastomer seals.	Oil
Used cooking oil	Post commercial use cooking oil. Very limited availability Existing markets in biodiesel	No limits	35 GJ/tonne	5	May contain animal by-products and be subject to animal by-products regulations. This might require 850°C for 2 secs	No change	Minor modification Minor modifications to atomiser, fuel preheat and elastomer seals.	Oil

Fuel	Description	Appropriate scale	LHV	Ref	Contamination that might impact on the process	Max Flame temperature compared with fossil fuel comparison. (Based on 15% excess air and 200°C preheat. Ref 7)	Change to burner	Fossil comparison
Tallow	By-product from animal rendering. Very limited availability Existing markets in biodiesel and oleo chemistry.	No limits	38 GJ/Tonne	5	Contains animal by-products and is subject to animal by-products regulations. This might require 850° C for 2 secs depending on source.	No change	Minor modification. Minor modifications to atomiser, fuel preheat and elastomer seals.	Oil
Talloil	By product of pulp and paper manufacture. Derived from lignin. Similar to heavy fuel oil Imported from Scandinavia. Limited availability. Existing markets for biodiesel and oleochemistry.	No limits	38 GJ/Tonne	6	Few. May contain some alkali metal salt that could cause minor fouling.	No change	Minor modifications to seals.	Oil, heavy fuel oil

Fuel	Description	Appropriate scale	LHV	Ref	Contamination that might impact on the process	Max Flame temperature compared with fossil fuel comparison. (Based on 15% excess air and 200°C preheat. Ref 7)	Change to burner	Fossil comparison
Pyrolysis oil	Liquid formed by heating biomass in oxygen free conditions and condensing the produced vapours. Not commercially available, some used on demonstration basis for district heating in Finland. Successful trials on fired wood kilns in Canada.	Unlikely to be suitable for smaller equipment	16.43 GJ/tonne @ 20% moisture	5	Few. Trace sulphur. Metals depend on source. Quality is very variable and some sources may have particulates that might result in fouling.	Somewhat lower	Major modification to burner. Fuel pipework and pump replaced in stainless, new atomisers, fuel and burner air preheat. New refractory components inside process to retain ignition. Ref 8	Oil, heavy fuel oil
Biodiesel	Produced by trans esterification of plant and animal oils and fats with alcohol. Properties essentially identical to diesel. Few barriers for supply a replacement for heating oil	No limits	38 GJ/tonne		Fewer than fossil equivalent. May have residual alkali catalyst and glycerol. There may be a tendency to use substandard material for heat	No change	No changes	Kerosene, light oils

Fuel	Description	Appropriate scale	LHV	Ref	Contamination that might impact on the process	Max Flame temperature compared with fossil fuel comparison. (Based on 15% excess air and 200°C preheat. Ref 7)	Change to burner	Fossil comparison
Ethanol	Produced by fermentation of sugars and separation of alcohol. Often imported from Brazil No infrastructure for supply as a fuel	No limits	26.7 GJ/Tonne		None	Lower	Major modification to fuel storage, pump, burner nozzles and seals	Natural gas, electricity
Virgin wood pellets burned in a combustion appliance	Clean wood pressed into 6mm dia. pellets. Free flowing clean solid fuel. Heat can be transferred via flue gas alternatively as clean hot air via a heat exchanger Pellets can also be used in a device that will create a flame similar to an oil flame.	No limits on flue gas heat transfer. Typically 50 - 500kW for air heater	19.05 GJ/tonne @ 9% moisture	6	Typically 0.5% ash. Otherwise few trace metals.	Limited to 900°C by ash melting	Replace. New burner assembly required. Can burn directly in coal fuelled boiler with minimal changes	Coal, Oil, natural gas
Virgin and grade A waste wood chip burned in a combustion appliance	Clean wood cut into pieces. Should contain no contamination beyond small proportion ash. Heat can be transferred via flue gas alternatively as clean	No limits on flue gas heat transfer. Typically 50 - 500kW for air heater	11.5 GJ/Tonne @ 34% moisture		Typically 0.5% ash. Otherwise few trace metals.	Limited to 900°C by ash melting	Replace. New combustion grate installation required	Oil, natural gas

Fuel	Description	Appropriate scale	LHV	Ref	Contamination that might impact on the process	Max Flame temperature compared with fossil fuel comparison. (Based on 15% excess air and 200°C preheat. Ref 7)	Change to burner	Fossil comparison
	hot air via a heat exchanger.							
Grade B and C waste wood chip burned in a combustion appliance	Wood extracted from waste streams will contain contamination from coatings, preservatives and metal fixings. Heat transferred via flue gas	No limits	13.7 GJ/Tonne @ 23.3% moisture.	6	Lead, Copper Chromium, arsenic. Zinc, Chlorine, fluorine from coatings and preservatives. Tramp metal. Ash typically 5%	Limited to 800°C by ash melting	Replace. New combustion grate installation required. Environmental Pollution Control (EPC) necessary	Heavy fuel oil, solid fuels

Fuel	Description	Appropriate scale	LHV	Ref	Contamination that might impact on the process	Max Flame temperature compared with fossil fuel comparison. (Based on 15% excess air and 200°C preheat. Ref 7)	Change to burner	Fossil comparison
Solid recovered fuel (SRF) burned in a combustion appliance	Paper card and other combustible materials sorted from the waste stream, dried and shredded. No infrastructure for supply as a fuel uncertain renewable content Difficult to store and handle No quality standards to underpin contracts Heat transferred via flue gas	No limit	13.4 GJ/tonne @ 22.3% moisture.	6	High chlorine, metals and dust Ash typically 11.7%	Limited to 800ºC by ash melting	Replace. New combustion grate installation required. Environmental Pollution Controls necessary	Heavy fuel oil, solid fuels

Fuel	Description	Appropriate scale	LHV	Ref	Contamination that might impact on the process	Max Flame temperature compared with fossil fuel comparison. (Based on 15% excess air and 200°C preheat. Ref 7)	Change to burner	Fossil comparison
Torrified wood pellets	Biomass is heat treated to 220 - 300°C at which point the structure shrinks and an irreversible loss of moisture occurs. The resulting material is friable and hygroscopic with an energy density approaching that of coal. This makes it attractive for long distance transport and coal substitution. Most current work concentrates on wood as a starting point but the process works with all biomass and effectively offers the promise of a fuel with consistent properties irrespective of the feedstock.	No limit	20.7 GJ/tonne @ 0% moisture.	5	Depends on input material but typically as wood pellet	Limited to 900°C by ash melting in appliances.	Can replace coal directly otherwise as pellets.	Coal, oil, natural gas

References

1 Gengas. The Swedish Experience 1939 – 1946.

2 Basic data on biogas2nd edition. 2012, Swedish Gas Centre www.sgc.se (Visited date: 24/10/14)

3 Technical Data on fuel. Seventh edition. Rose and Cooper, 1977

4 Dunphy Combustion. Product and applications overview. http://www.dunphy.co.uk/product_range/default.htm (Visited date: 24/10/14)

5 Phyllis database. https://www.ecn.nl/phyllis2/Browse/Standard/ECN-Phyllis#animal fat (Visited date: 24/10/14)

6 The Fuel Handbook 2012. Birgitta Strömberg, Solvie Herstad Svärd. Report ref A08-819. VÄRMEFORSK Stockholm

7 IEA Bioenergy Agreement, Task 32. Fuel sim V4.2 combustion calculation tool

8 Fuel oil quality and combustion of fast pyrolysis bio-oils. Jani Lehto | Anja Oasmaa | Yrjö Solantausta |Matti Kytö | David Chiaramonti. VTT Finland 2013

9 http://www.ieatask33.org/app/webroot/files/file/publications/new/Gas_cleaning.pdf (Visited: 24/10/14)

10 http://www.ieatask33.org/app/webroot/files/file/2013/Workshop_Gothenburg/19/ClaesBreitholtz.pdf(Visited: 24/10/14)

11 http://www.ieatask33.org/app/webroot/files/file/2013/Workshop_Gothenburg/19/Rauch.pdf (Visited: 24/10/14)

12 http://www.nexterra.ca/ (Visited date: 24/10/14)

2.4. Composition of Combustion products

Solid biomass

Solid biomass has a more complex composition than most fossil fuels. At the point of combustion the flue gas from solid biomass will contain the normal flue gas combustion products, unburned fuel, all of the ash components in dust or aerosol form plus inorganic compounds such as halogens. If the process can tolerate the incorporation of these components, then the biomass can be burned in its original form.

If the nature of the process cannot tolerate contamination, then several strategies can be adopted depending on the final application:

- Biomass is converted to producer gas which is subsequently cleaned before use
- If a higher temperature is required, then the biomass can be converted to syngas which is subsequently cleaned
- Clean hot air is generated by heat exchange with biomass combustion.

Gaseous fuels

The composition will reflect the upstream process used to produce the fuel. Raw producer gas and biogas directly from anaerobic digestion will contain contaminants that could impact on the primary process if the products are sensitive. Filtering and liquid scrubbing will remove the contaminants, and give a gas that is more compatible.

The composition product of hydrogen is simply water vapour.

Liquid fuels

Biomass derived liquids can be used to substitute for fossil oils. Composition is broadly similar to fossil oils with relatively little impact on the downstream process.

2.5. Compatibility with Incumbent Burners

Compatibility is highly dependent on the properties of the fuel.

Where the incumbent fuel is solid then relatively low levels of fuel replacement with alternative solid fuels such as biomass may be possible with minimal changes to the fuel feeding speed control and combustion air fan capacities. For higher levels of substitution, however, it may be necessary to introduce more burners, upgrade the draught fan or even enrich the oxygen content of the combustion air, due to the lower calorific value of biomass relative to the most likely solid fuel being replaced (coal) and higher moisture content.

Where the incumbent fuel is gas or oil then the heat consuming process can be assumed to require a flame for the transfer of heat to process. Replacement with a solid fuel would require the solid fuel to be pulverised and blown through a burner. This may be possible in some applications (e.g. cement kiln), but in applications where the presence of un-combusted solid matter cannot be tolerated (e.g. a glass melting furnace), the use of pulverised solid fuel would be discounted as an option. In these cases, the replacement fuel would have to be a gas or liquid. Moreover, pulverised solid fuel would require additional energy to be expended, thereby affecting the absolute CO_{2e} saving available.

Assuming that the composition of the combustion products of a replacement fuel are acceptable to the process, the extent to which an incumbent gaseous fuel may be replaced by a replacement gaseous fuel will depend on a number of factors including the following:

1. The caloric value of the replacement fuel relative to the incumbent fuel
2. The relative density of the replacement fuel relative to the incumbent fuel
3. The flame speed of the replacement fuel relative to the incumbent fuel.

For a given burner and for a given pressure of fuel gas at the burner, the calorific value and relative density of the fuel gas will determine the heat generated by the burner. The greater the calorific value of the fuel, the greater the heat that will be generated. For a given fuel gas pressure and burner port area, the greater the relative density of the gas the less gas will flow through the burner and less heat will be generated.

This relationship between calorific value and relative density of fuel gases is summed up by a parameter known as the "Wobbe number", derived as follows:

$$Wobbe\ number = \frac{Calorific\ Value\ of\ Gas}{\sqrt{Relative\ Density\ of\ Gas}}$$

In theory, for the same gas pressure at a particular burner, two gases with the same Wobbe number will generate the same heat. If quantity of heat generated were the only important parameter, then those two fuels can be considered interchangeable[17].

Another important parameter to consider when evaluating the case for replacing the fuel gas is the flame speed. The flame speed is the rate at which the flame front travels through a completely self-burning mixture of gas and air. Flame speed is an important parameter to consider for premix burners. If the flame speed is too high and the rate at which the mixture of fuel and air emerging from the burner is too low, then it is possible to get 'burn-back'. Conversely, if the rate at which the mix of fuel and air emerges from the burner is too great for the flame speed then the flame may lift away from the burner and go out.

Putting the same quantity of heat into a kiln or furnace will not necessarily achieve the same heat transfer as before and the end user would usually require extensive testing, both on a test rig and in-situ, before they were confident that the heat consuming process is operating without unacceptable changes to product quality and product throughput. Where the heat consuming process is business critical, it may be difficult to secure time for such tests.

The extent of modification required to burners is set out in more detail in Table 2. **It should be noted, however, that from contact with burner suppliers we are assuming that existing natural gas burners cannot be viably converted to burn other gaseous fuels without the burner being replaced. This is the basis of the cost analysis carried out for the processes using gaseous fuels.**

2.6. Availability of Fuels

2.6.1. Biomass

The following figures are taken from UK and Global Bio-Energy Resource and Prices, AEA for DECC 2011[18]. It should be noted that new evidence on availability and CO_{2e} emissions associated with biomass has recently been published[19]. The standard CO_{2e} factor for biomass

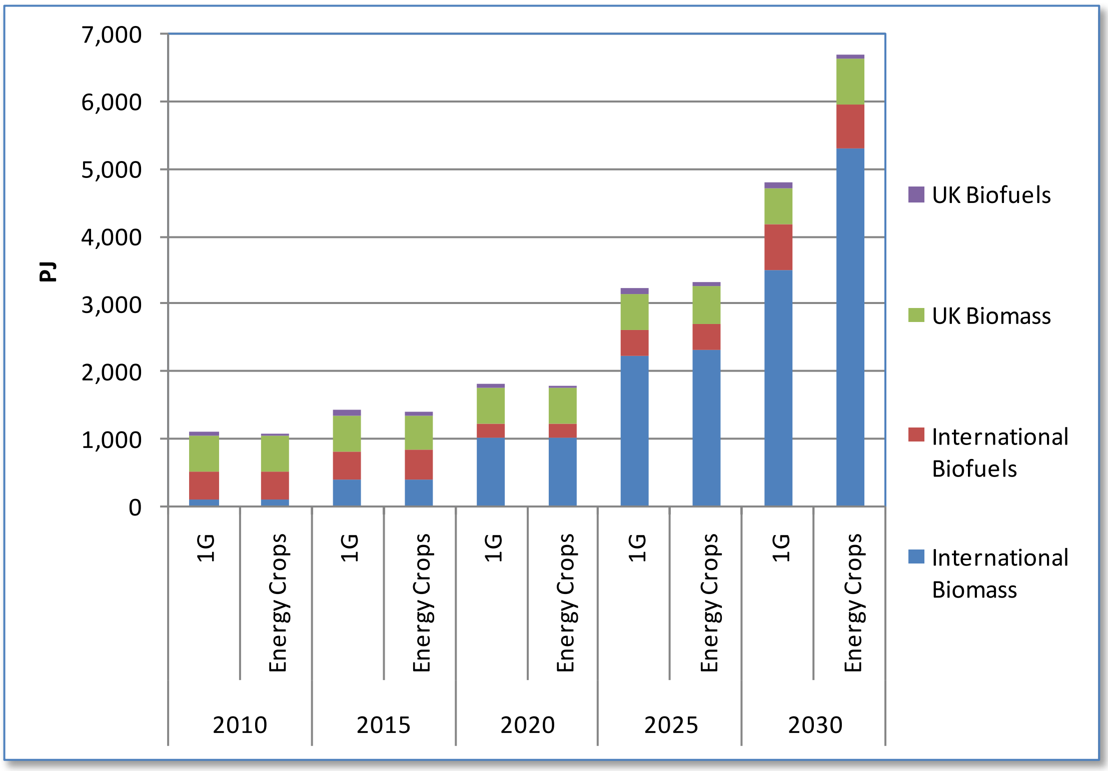
---

[17] Other considerations must be made, including composition of combustion products, flame speed and flame luminosity

[18] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48059/1464-aea-2010-uk-and-global-bioenergy-report.pdf (Visited 24/10/14)

[19] https://www.gov.uk/government/publications/life-cycle-impacts-of-biomass-electricity-in-2020 (Visited: 24/10/14)

Figure 2 Biomass resource available to UK at £10/GJ with easy and medium constraints met for land use maximised for first generation biofuels crops (1G) and land use maximised for energy crops



used in this report ensures consistency with other DECC analyses, however up-to-date agreed values will be used for analysis of any policy proposals which might be developed in the future.

Figure 2 shows the biomass resource estimated to be available to the UK, if easy and medium constraints are overcome, and assuming a business as usual global scenario. The availability of UK based feedstock is shown in Figure and Figure .

Note: These graphs include data from the UK at £10/GJ with easy and medium constraints addressed; and the international resource for the BAU scenario, using the reference demand scenario. For a full explanation of the terms and scenarios used in these plots, refer to Appendix 13 – Detail of Biomass Scenarios Presented in Section 2.6.1*.*

Figure 3 Summary of results for UK biomass supply with no constraints met and assuming maximum production of energy crops on available land. Supply is shown for £4/GJ no constraints met, £6/GJ easy and medium constraints met and for £10/GJ all constraints met.

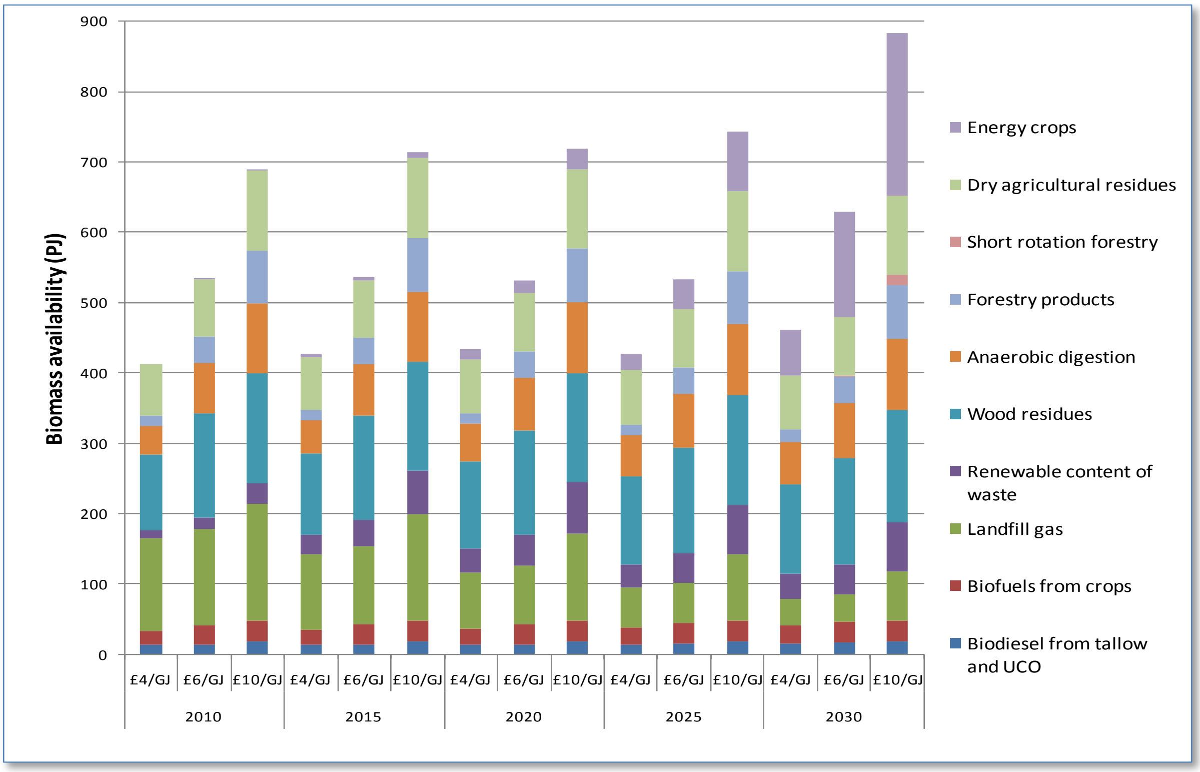
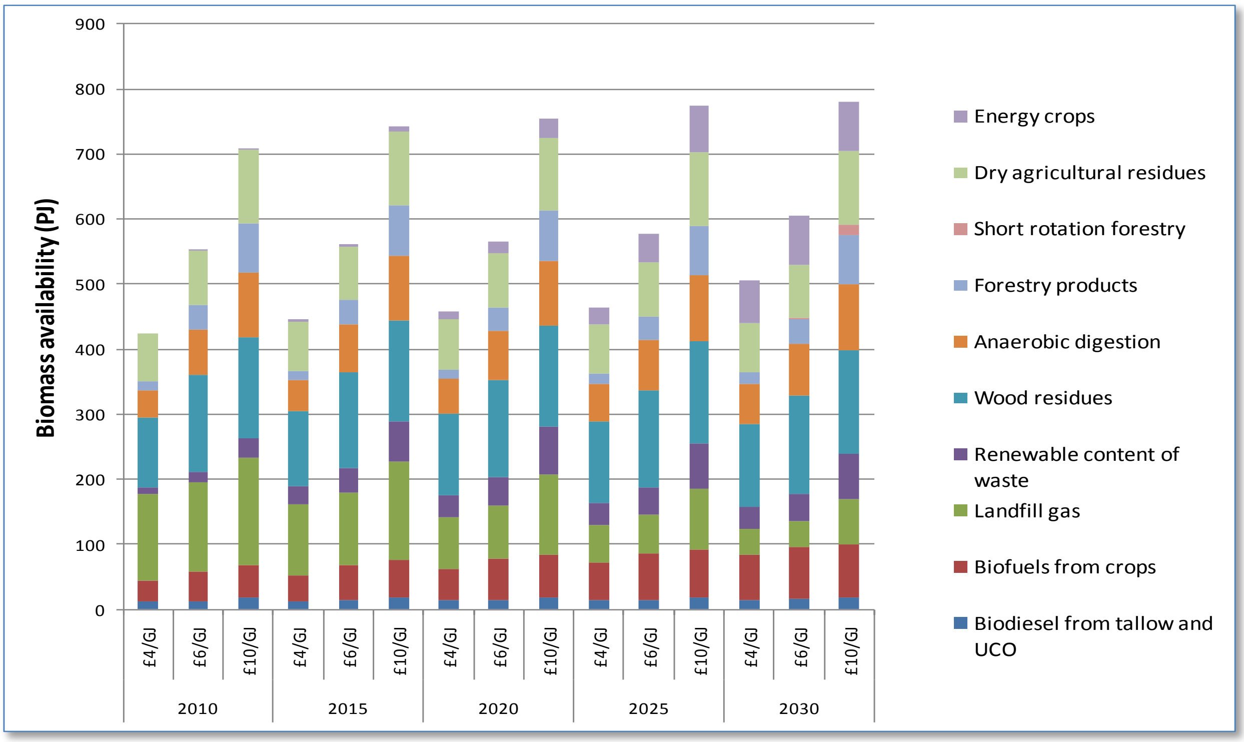


Figure 4 Summary of results for UK biomass supply assuming maximum production of first generation biofuels crops on spare land. Supply is shown for £4/GJ no constraints met, £6/GJ easy and medium constraints met and for £10/GJ all constraints met.



2.6.2. Biogas

Biogas is produced via the anaerobic digestion of waste and/or dedicated energy crops. Since biogas has methane as its main component, if it is cleaned-up (i.e. removal of hydrogen sulphide and other contaminants) and upgraded (removal of CO_{2e} that can account for up to 40% of biogas by volume) it can be injected into the natural gas grid. Incentives already exist encouraging this practice. There are also incentives in place to generate electricity from the combustion of biogas. These facts, together with the need for suitable animal and vegetable matter to arise in relatively close proximity to where the gas is either injected to the gas grid or combusted, means that we can expect there to be limited availability of biogas for combustion for the generation of direct heat in industry.

A Committee on Climate Change (CCC) report[20] indicates that only 0.9% of biogas generated in 2020 will be made available for direct heat use, with 62% destined to be injected to the gas grid and the balance used to generate electricity in power only or CHP plant. As such, in this study we assume that there are limited opportunities for the consumption of biogas for the generation of direct heat in industrial applications.

2.6.3. Hydrogen

We have not been able to locate any work considering the availability of hydrogen where this hydrogen is not generated as a by-product.

2.6.4. Fuels Made from Waste

As discussed above, we are considering in this study SRF and Grade B and C waste wood.

SRF is produced by Mechanical and Biological Treatment (MBT) and Mechanical and Heat Treatment (MHT) installations. According to a 2012 study carried out for WRAP[21], if all of the MBT and MHT installations planned become operational, then an additional 2.5 Mt of SRF will become available on top of an estimated 0.8 Mt of SRF produced by existing installations[22]. The total quantity of SRF that may become available would therefore be 3.3 Mt. At a GCV of about 15 MJ/kg, this represents 13.8 TWh.

Regarding the availability of waste wood, the same study identified 2.2 Mt of waste wood currently going to landfill on top of un-landfilled waste wood of ~3.4 Mt[23], giving a total waste wood availability of 5.6 Mt. With a GCV of ~13 MJ/kg, this corresponds to 20.2 TWh. However, it should be noted that almost 2 Mt is already used in energy recovery schemes and so a more realistic estimate of the additional availability of waste wood would be that currently going to land fill (2.2 Mt, 7.9 TWh).

---

[20] The Renewable Energy Review, p.127 http://archive.theccc.org.uk/aws/Renewables%20Review/The%20renewable%20energy%20review_Printout.pdf (Visited 24/10/14)

[21] Energy from Waste Market Research – Investigating the opportunities for waste derived fuels and process heat, 2012

[22] Energy from Waste Market Research – Investigating the opportunities for waste derived fuels and process heat, 2012 See Table 12

[23] Energy from Waste Market Research – Investigating the opportunities for waste derived fuels and process heat, 2012 See Table 7

2.6.5. Syngas

The availability of syngas depends upon the availability of waste and biomass material that can be gasified. This waste and biomass will already have competing uses which would have to be discontinued if the supply of syngas were to be increased.

However, in order to set some magnitude to the theoretical availability of syngas, it may be instructive to note that total waste arising in the UK are estimated at 221 Mt[24] (798 TWh). With waste to syngas conversion efficiencies of 78%, this implies around 600 TWh of syngas.

As recycling rates increase, the calorific value of waste available for gasification is expected to drop, leading to a fall in the calorific value of the syngas produced. This might make it necessary for waste to be supplemented by other forms of biomass, e.g. wood chip. This would raise the cost of the syngas produced primarily from the gasification of waste.

2.6.6. Industrial Process Gases

Industrial process gases arise as a by-product of the processes being carried out at a particular site. These gases arise in the Iron & Steel, Chemical and Oil Refining sectors, and examples are given in Section 2.1. The availability of these gases is therefore site specific and availability and use of these gases is therefore considered in each sector’s dedicated section.

---

[24] Energy from Waste Market Research – Investigating the opportunities for waste derived fuels and process heat, 2012 See Table 1

3. Characteristics of Glass Sector

3.1. Glass Sector – Sub-sectors and Direct Heat Consuming Processes

3.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat

The Glass sector is comprised of the following sub-sectors:

- Flat Glass
- Container Glass
- Fibre Glass
- Special glass[25]
- Glass manipulator[26]

The relative importance of these sub-sectors in terms of the quantity of fuel consumed for the generation of direct heat is summarised in Table 3. The data for the Fibre Glass, Special Glass and Glass manipulator sub-sectors is amalgamated for reasons of confidentiality.

Table 3 Glass Sector Summary (Data for 2012 supplied by British Glass). Data presented as received

Sector/Sub-sector	Annual Fuel Consumption for All Heat (MWh)	Annual Fuel Consumption for Direct Heat (MWh)
Flat	6,500,000	1,903,825
Container		4,221,426
Other		311,465
Glass (Total)		6,436,716

Overall, about 99% of the fuel used to generate heat in the Glass sector is used for the generation of heat supplied direct to process.

---

[25] Example products made by this sub-sector are crystal tableware.

[26] Glass manipulators form and shape glass rather than make it from the raw ingredients. Examples of products made in this sub-sector include toughened safety glass and ballotini (small glass spheres added to reflective paint products.

3.1.2. Direct Heat Consuming Processes

The main direct heat consuming processes carried out in the Glass sector are given in Table 4.

Table 4 Direct Heat Consuming Processes (Data for 2012 supplied by British Glass)

Direct Heat Consuming Process	Annual Fuel Consumed for Generation of Direct Heat (MWh)	Temperature Requirements of Process (ºC)	Characteristics of Heat – Hot Air Composition
Melting (all subsectors)	5,857,884	1650	Must be free of particulate matter
Forehearth (Container)	192,000	1050-1200	Must be free of particulate matter
Lehr (Container)	192,000	580 (process temp)	Characteristics of hot air less exacting than where molten glass is involved in the process, in that particulates will not be incorporated in the body of the final product, but might merely be deposited on to the surface of the product and could be removed subsequently.
Bath (Flat)	180,000	600-1000	Must be free of particulate matter
Forming (Other)	14,832	Various	Must be free of particulate matter
Total	**6,436,716**		

Overall, a little over 90% of fuel consumed for the generation of direct heat is for the melting of glass. The processes consuming direct heat and the nature of the process are listed below:

Melting – This takes place in furnaces that are fired by a range of burner types, including: cross-fired regenerative burners, end-fired regenerative burners and oxy-fuel fired burners[27]. The main fuel used for melting is natural gas (91%) followed by fuel oil (6%) and electricity (2%). Electricity is an expensive fuel compared to natural gas and is therefore not used as the ‘workhorse’ for heat supply, but rather to perform special roles. These special roles include setting up thermal currents in the molten glass bath via passing current through electrodes to promote homogeneity and to temporarily increase the total thermal capacity of the glass furnace at times of high demand. Fuel oil is most probably used as a back-up fuel to natural gas in cases where the natural gas consumer is on an interruptible supply.

---

[27] Oxy-fuel burners use pure oxygen rather than air to support combustion. Pure oxygen combustion produces flames of higher temperature than air flames. Using pure oxygen reduces the volume of gases leaving the process,

Forehearth (container) – The refractory lined channel connecting the glass melt in the furnace to the point at which ‘gobs’ (precursors to the final container glass product) are cut off. Natural gas is the main fuel used for heating the forehearth (85%) with the balance of the heat provided by electricity (15%) consumed in resistive heaters or electrodes.

Lehr (container) – A continuous annealing oven used to reheat the formed container product in order to relieve any stresses set up during the rapid cooling during the forming process. Natural gas is the main fuel consumed to generate heat for the Lehr (70%) with the balance provided by electricity as radiant heaters.

Bath (Flat) – The refractory lined bath on which molten glass ‘floats’ on molten tin, allowing a product of uniform thickness and near perfect flatness to develop. Heat is normally supplied directly from electric radiant heaters, although natural gas is used if the electric radiant burners cease to operate.

Forming – A generic term for the process by which certain special glass products are formed. Heat is provided in the form of electricity to render the glass plastic enough to allow the desired form to be achieved.

3.2. Glass Sector – Characteristics of Direct Heat Consuming Processes

3.2.1. Types of Fuel Used

This Section sets out the relative importance of each direct heat consuming process in terms of fuel consumption.

Table 5 summarises the types of fuel currently used in each process.

Table 5 Fuels Used (Data for 2012 supplied by British Glass)

Process	Natural Gas	Fuel Oil	Electricity
Melting (all subsectors)	91.8%	6.2%	2.0%
Forehearth (Container)	85.0%	0.0%	15.0%
Lehr (Container)	70.0%	0.0%	30.0%
Bath (Flat)	0.0%	0.0%	100.0%
Forming (Other)	0.0%	0.0%	100.0%
Total	**88.2%**	**5.6%**	**6.2%**

Currently, natural gas constitutes a very large majority of total fuel consumption for the generation of direct heat (88.2%). The second most used fuel is electricity (6.2%) followed by fuel oil (5.6%). The largest consumption of electricity in absolute terms occurs in melting. Electrodes are strategically placed within the melting tank primarily to generate thermal currents to increase the homogeneity of the glass melt. Electricity can also be used to supplement heat from the other fuels if demand for molten glass exceeds the melting capacity of the installed burners. However, in such cases a balance has to be struck between the value associated with

---

as the nitrogen making up almost 80% of air is avoided. This reduces the quantity of heat lost up the stack, leading to a more efficient process. Gas fuels burning in pure oxygen will also burn with a higher flame speed.

increased throughput of the furnace and the higher cost of electricity. Electricity could be used to a greater extent for glass melting, but the cost of electricity means that heat is first sought from combustion of fuel before recourse to electricity.

Currently none of the renewable and low carbon fuels under consideration in this study are consumed with in the Glass sector.

3.2.2. Fuel Costs

Fuel costs paid by industry vary according to demand. This is demonstrated in DECC's Quarterly Energy Prices document[28], where, for consumers of fuels, prices are presented according to three sizes of consumer (small, medium and large).

Owing to the preponderance of natural gas consumption in the Glass sector, the size categories and fuel prices pertaining to natural gas are referred to here.

Flat Glass - In the Flat glass sector the average fuel for heat consumption is a little over 384,000 MWh per site. This would place the average flat glass site in the 'large' category, paying 2.403 p/kWh (excl. CCL).

Container Glass - In the Container glass sector the average fuel for heat consumption is a little over 355,000 MWh per site. This would place the average flat glass site in the 'large' category, paying 2.403 p/kWh (excl. CCL).

Other – This sub-sector includes sites with a wide range of fuel consumption. For confidentiality reasons, the sector association was not able to share fuel consumption data that would illustrate this range.

3.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions

The specific energy consumption and specific CO_{2e} emissions for each of the five main direct heat consuming processes are set out in Table 6. The unit of throughput is in terms of tonnes of product emerging from the process. Therefore, in the case of the process 'Melting' the throughput is in units of tonnes of glass melted. For downstream processes, the throughput is in terms of tonnes of final product.

Table 6 Specific Energy Consumption and CO_{2e} Emissions (Data for 2012 supplied by British Glass)

Direct Heat Consuming Process	Specific Energy Consumption (MWh/tonne)	Specific CO_{2e} Emissions (tCO_{2e}/tonne)
Melting (all subsectors)	1.621	0.334
Forehearth (Container)	0.085	0.018
Lehr (Container)	0.085	0.018
Bath (Flat)	0.248	0.050
Forming (Other)	0.161	0.030

---

[28] https://www.gov.uk/government/publications/quarterly-energy-prices-december-2013 December 2013 (Visited 24/10/14)

From this it is clear that glass melting is easily the most energy and CO_{2e} intensive of the processes.

3.2.4. Heat Load Factors

The Heat Load Factors we report here are ‘fuel for direct heat load factors’, as the information we have received from sectors is based on quantified fuel consumption for the generation of heat rather than quantified consumption of heat. Determining the quantity of heat consumed requires knowledge of:

1. The quantity of fuel consumed, and
2. The quantity and condition of hot air and combustion products leaving the process after heat has been given up to process.

When the value for 2 is divided by the value for 1 the result is the overall efficiency with which energy contained in the fuel is converted into heat and subsequently transferred to process. This efficiency will vary from process to process and according to the specific requirements of the process.

Fuel for direct heat load factors is calculated as follows:

$$\frac{\text{Fuel Consumed in Process (MWh)}}{Capacity\ of\ Heat\ Generating\ Technology\ (MW) \times 8760\ hrs}$$

This gives an indication of the extent to which the capacity to generate heat is utilised over the course of a year. This requires knowledge of the number and capacity of burners, which in the Glass sector is only readily available for glass melting furnaces in the main sub-sectors of flat glass and container glass. Table 7 shows an approximate estimate of burner capacity in glass melting furnaces in these two sub-sectors.

Table 7 Estimated Burner Capacity (Data for 2012 supplied by British Glass)

Sub-sector	Approximate Total Burner Capacity (MW)	Annual Fuel Consumption for Glass Melting MWh)	Implied Load Factor (%)
Flat	245	1,723,825	80.3
Container	553	3,837,426	79.2

3.3. Types of Burner Used

In order to get a detailed understanding of the technical potential for the candidate fuels to be burned to supply direct heat for process, it is necessary to categorise the incumbent burner systems into certain generic types. This is because different burner systems are expected to have different inherent potentials to burn the candidate fuels in an unmodified state and will have to undergo different modifications in order to increase the proportion of candidate fuel that can be burned. However, the current information we have received from burner suppliers indicates that the candidate gaseous fuels cannot be burned in burners set-up to burn natural gas and that the existing burners would have to be completely replaced if the candidate gaseous fuels were to be combusted. Moreover, alternative burners will have to be NOx compliant.

3.3.1. Diffusion Burner

Diffusion burners are used in glass melting furnaces and are therefore the burner technology associated with the process ‘Melting’. The burners used for melting are either end-fired regenerative burners or cross-fired regenerative burners. Diffusion burners produce long, luminous flames and this flame exchanges heat with the charge via radiative heating. In glass melting, it is necessary for the diffusion flame to be long enough so that it can exchange heat with the whole molten glass tank.

In diffusion burners neat gas is supplied to the burner head and the oxygen required for combustion is supplied by the surrounding atmospheric air. The rate of combustion depends upon the rate of mixing between the air and neat fuel gas. It therefore follows that ensuring that the flame covers the glass tank requires control over the speed of combustion which is in turn determined by the flame speed of the fuel gas and the rate at which oxygen diffuses in to the neat fuel stream.

3.3.2. Pre-mixed Burners – Nozzle Burners

Nozzle burners are used in the lehrs, where the glass product is annealed so as to relieve residual stresses set up during product formation. Nozzle burners are considered a type of pre-mixed burner because mixing of the fuel and air occurs before combustion.

3.3.3. Pre-mixed Burners – Manifold Pre-mix

These manifold pre-mix burners are used in the forehearth. These burners are considered a type of pre-mixed burner because mixing of the fuel and air occurs before combustion.

3.4. Technical Potential for Candidate Fuel Consumption and Barriers

3.4.1. Suitability of Candidate Fuels

Melting is predominately carried out using burners producing long diffusion flames in the glass melting furnace. These flames have to cover either the length (in the case of end fired) or the width (in the case of cross-fired) of the furnace in order for heat to be efficiently transferred to the glass melt. The flame sits above the molten glass and transfers heat to it via radiative heating. This close proximity of flame to melt and strict product quality requirements mean that a clean flame, free of particulates, is essential.

While the solid, candidate fuels in pulverised form could in theory be blown through existing natural gas burners, the smallest degree of incomplete combustion would lead to particulate matter being incorporated in the glass melt. For this reason only the potential to burn gaseous candidate fuels is considered in the sections below. The candidate fuels that are considered further are, therefore, biogas, hydrogen, syngas and electricity.

Note: Electricity can only be considered as a candidate fuel in so far as some glass melting uses electricity to boost the thermal capacity of the furnace (see below). There is a small potential to increase the proportion of total heat coming from electricity in these cases without changing the entire process and transfer, for example, from a situation where 100% fossil fuel is displaced by 100% electricity, as such radical process changes have their own complex issues and deserve a dedicated study. Moreover, the following should be considered regarding the use of electricity for the generation of heat:

1) Although electrical heat is delivered to process more efficiently than heat from combustion of a fuel (because of losses up the stack in the latter), electricity sourced

from the grid will not be of low enough carbon intensity for many years into the future to represent a lower carbon option than the main incumbent fuel, natural gas.

2) To avoid the residual carbon content of grid electricity, a site might generate electricity from renewable sources and use that electricity to generate heat. However, that electricity would be subject to incentives under the Renewables Obligation scheme. As the site would, presumably, not be allowed to receive an incentive twice in respect of the same electricity (once under the Renewables Obligation scheme and once under the Renewable Heat Incentive), the site would likely opt for the incentive paying more. For the site to choose to use the electricity for heat, the RHI against this electricity would have to be at least 5p/kWh and more, depending upon the electricity generation technology.

3.4.2. Technical Barriers to Candidate Fuel Use

The following technical barriers exist in respect of each of the candidate fuels being considered:

Biogas – Raw biogas directly from an anaerobic digester will contain hydrogen sulphide and other acid gases that may have implications for furnace components. As such biogas would have to be cleaned-up before it could be combusted in a glass furnace. Cleaned biogas would still be dilute from the point of view of methane content and would contain CO_{2e} in the range 30-40%[29]. This means that the calorific value of cleaned biogas is significantly lower than natural gas. Consequently, for the same burner power to be attained, burner modifications would be needed to allow a higher volume throughput of fuel gas. Increasing the volume of fuel in a confined space such as the combustion chamber sitting above the molten glass bath in a glass melting furnace may require changes to the size of the combustion chamber in order to maintain the right internal pressure. This becomes more likely the higher is the substitution rate. Increasing the volume of biogas entering the furnace may also have implications for the way heat is transferred to the molten glass. Cleaned biogas would burn with a lower flame temperature than natural gas. This will place limits on the extent to which cleaned biogas can displace natural gas unless complete burner replacement occurs. (It should be noted that upgraded biogas – where CO_{2e} is removed – could be substituted one for one with natural gas).

In the opinion of the sector existing diffusion burners can tolerate a degree of biogas substitution (~30%) without modifications being required to the burner. According to the sector association, substituting above this level would require modification to the burner. This is because, above this level, problems with mixing between the fuel and oxygen in the air are expected due to the presence of CO_{2e} in the fuel. This can be addressed, to a degree, by introducing turbulence in the air and/or fuel streams and changing the angle of attack between the fuel and air streams.

Hydrogen – The calorific value of hydrogen is only about 25% that of natural gas. Consequently, as with cleaned biogas, a greater volume of fuel will have to flow through the burner in order for the same burner power to be attained. While hydrogen burns with a flame with a higher temperature, its luminosity is lower than that of natural gas and so the efficiency with which heat is transferred to the glass melt would be compromised. This will place limits on the extent to which hydrogen can displace natural gas in an application such as glass melting where radiation from the flame is an important mechanism for getting heat into the glass melt. Moreover, hydrogen burns with a very high flame speed, such that burn-back may be a problem for pre-mixed burners unless the speed with which the fuel air mixture emerges from the nozzle is increased.

---

[29] If this gas were to be injected into the gas grid this CO_2 would have to be removed.

Syngas[30] – The calorific value of syngas is in the range of about a third to three quarters that of natural gas, depending upon the composition of the waste or biomass being oxygen blown gasified. Consequently, for a significant degree of displacement of natural gas with syngas, burner modifications would be required in order for larger fuel volume throughput to be possible, if the same burner power is to be achieved. While hydrogen makes up a significant proportion of the composition of syngas, the presence of carbon monoxide in the gas mitigates problems of flame luminosity associated with a pure hydrogen fuel. It should be noted that scrubbing of the syngas would be necessary for applications where tars are present in the syngas.

Electricity – The potential to use greater proportions of electricity in glass melting is restricted by the effect of localised heating produced by electrodes in the melting furnace. This localised heating can cause the refractory material lining the molten glass tank in the vicinity of the electrodes to wear out more quickly than the rest of the refractory material, potentially leading to leaks. With a complete rebuild to address the refractory problem it is technically possible to melt glass in full electric furnaces, but the potential to do this is not considered further in this study for the reasons given in Section 3.4.1. It is, however, possible to modestly increase the proportion of heat input to the furnace coming from electricity using existing electrode arrangements and the potential for this is considered below.

Diffusion Burners

In the opinion of the sector, even after taking into account the above technical challenges associated with fuel substitution, existing diffusion burners could tolerate a degree of biogas (30%), hydrogen (10%) or syngas (10%) substitutions without modifications being required to the burner. However, the burner manufacturer may not sanction this in which case the end user may not be able to move forward with the substitution. Substitution above this level would require modifications. These modifications would include:

- In respect of the lower calorific value associated with the above candidate fuels of biogas, hydrogen and syngas, increasing the nozzle size to allow for a greater volume of fuel to flow, so as to deliver the required heat.
- In respect of hydrogen and syngas, changes to the air nozzle size to change the volume of air being introduced to preserve a stoichiometric air: fuel ratio.
- In respect of biogas, changes to the burner to increase the degree of mixing between the fuel and air streams to ensure that, by the end of the diffusion flame, complete combustion of the biogas has been achieved.
- In respect of hydrogen (and to a lesser extent syngas, which has a significant proportion of hydrogen) decrease the degree of mixing between the fuel and air streams. This compensates for the high flame speed for hydrogen which, in the case of a diffusion flame, could prevent the flame from achieving coverage across the whole furnace width or length. Slowing down the rate at which fuel and air mix affords the flame the opportunity to cover the whole furnace length (in the case of end-fired furnaces) or width (in the case of cross-fired furnaces).

---

[30] In this study syngas is being treated as distinct from ‘Producer Gas’. Producer gas is a lower calorific value fuel gas produced from air blown gasification of solid waste or biomass. The lower calorific value of Producer Gas relative to Syngas is a consequence of nitrogen being present in the former but absent in the latter. The presence of nitrogen is a consequence of using air in the gasification producing Producer Gas. Producer Gas would likely be available at a lower cost than Syngas, as the technology for producing the latter is more complex. However, burner modifications are expected to be more significant than for syngas, for a higher level of substitution of natural gas.

In addition to modification, fuel mixtures rich in hydrogen will generate a high water vapour pressure in the furnace environment which may attack the silica furnace crown. In extreme case, a new furnace crown material may be required.

Pre-mix Burners

Pre-mix burners are employed in the forehearth and lehrs. According to the sector association, mixing in forehearth burners occurs in a manifold and the fuel air mix is then passed onto the burners. In lehr burners, mixing of fuel and air occurs in the burner nozzle.

In the case of premixed burners, the issue associated with diffusion of oxygen into a neat fuel stream (as seen with diffusion burners) is not present as fuel and air are mixed prior to combustion. In the opinion of the sector, this means that biogas can be burned at replacement rates of 100% in current pre-mix burners. The more complex nature of nozzle burners used in the lehrs means that syngas can only be burned at levels of 30% without modifications to the burner, while the simpler arrangement in the manifold pre-mix burners used in forehearths means that syngas can be burned at 100% replacement rate without modification. In the case of hydrogen, for both manifold and nozzle mix burners, substitution at levels above about 10% would require the nozzle size to be increased to allow a greater volume of fuel to flow. Also, with pre-mixed burners, the high flame speed of hydrogen rich fuels could lead to flame burn- back. In order to counter this, modifications would have to be made to increase the speed with which the fuel air mix emerges from the nozzle. (Note that flame burn-back is not an issue with diffusion burners, because only a neat fuel stream emerges from the burner, rather than a fuel stream with entrained air).

3.4.3. Technical Potential for Candidate Fuel Use

The sector association has offered its own view of the potential to burn the candidate gases of Biogas, Hydrogen and Syngas in current burner systems, modified burner systems and replacement burners, as per Scenarios 1, 2 and 3, below and in Table 8 to Table 13:

- Scenario 1 Current Technical Potential – In this scenario no modifications to the incumbent heat generating technology (i.e. burner) are made. This scenario considers the maximum extent to which each of the candidate fuels may be used in the current burners.
- Scenario 2 Modified Technical Potential – In this scenario the basic incumbent burner is retained but modifications are made to the burner itself, or its supplementary equipment, in order to maximize the quantity of the candidate fuels that can be burned. Modifications to incumbent burners include:
    - Minor modifications, including atomiser nozzle, fuel pump elastomer seals, addition of a fuel heater to lower viscosity of liquids. These modifications involve components that are easily accessible and are changed routinely as part of a service.
    - Major modifications, including changes to the configuration of the burner head to cope with radically altered fuel properties such as flame speed, calorific values and poor ignition properties.
- Scenario 3 Replacement Technical Potential – In this scenario the incumbent burner is replaced with another, in order to increase further, beyond the Modified Technical Potential scenario, the quantity of candidate fuel that can be burned.

3.4.3.1. Flat Glass Melting (Diffusion Burners)

Table 8 Melting Scenario 1 (Estimates provided by British Glass)

Technology	Candidate Fuel			
	Biogas	**Hydrogen**	**Syngas**	**Electricity**
Cross-fired Regenerative	30%	10%	10%	10% (Container only)
End-fired Regenerative	30%	10%	10%	10% (Container only)
Oxy-fuel[31]	30%	10%	10%	0%

Table 9 Melting Scenario 2 (Estimates provided by British Glass)

Technology	Candidate Fuel			
	Biogas	**Hydrogen**	**Syngas**	**Electricity**
Cross-fired Regenerative	35%	30%	15%	10% (Container only)
End-fired Regenerative	35%	30%	15%	10% (Container only)
Oxy-fuel	35%	30%	15%	0%

Table 10 Melting Scenario 3 (Estimates provided by British Glass)

Technology	Candidate Fuel			
	Biogas	**Hydrogen**	**Syngas**	**Electricity**
Cross-fired Regenerative	100%	100%	100%	100%
End-fired Regenerative	100%	100%	100%	100%
Oxy-fuel	100%	100%	100%	100%

---

[31] Oxy-fuel burners use pure oxygen rather than air to support combustion. Pure oxygen combustion produces flames of higher temperature than air flames. Using pure oxygen reduces the volume of gases leaving the process, as the nitrogen making up almost 80% of air is avoided. This reduces the quantity of heat lost up the stack, leading to a more efficient process. Gas fuels burning in pure oxygen will also burn with a higher flame speed

3.4.3.2. Lehrs and Forehearths (pre-mixed burners)

Table 11 Lehr/Forehearth Scenario 1 (Estimates provided by British Glass)

Technology	Candidate Fuel		
	Biogas	**Hydrogen**	**Syngas**
Pre-mix burners (Forehearth - manifold)	100%	10%	100%
Pre-mix burners (Lehrs – nozzle mix)	100%	20%	30%

Table 12 Lehr/Forehearth Scenario 2 (Estimates provided by British Glass)

Technology	Candidate Fuel		
	Biogas	**Hydrogen**	**Syngas**
Pre-mix burners (Forehearth - manifold)	100%	30%	100%
Pre-mix burners (Lehrs – nozzle mix)	100%	40%	60%

Table 13 Lehr/Forehearth Scenario 3 (Estimates provided by British Glass)

Technology	Candidate Fuel		
	Biogas	**Hydrogen**	**Syngas**
Pre-mix burners (Forehearth - manifold)	100%	100%	100%
Pre-mix burners (Lehrs – nozzle mix)	100%	100%	100%

However, when contacted, companies supplying burners for the candidate fuels, as well as natural gas burners, have advised that natural gas burners vary significantly from burners designed specifically for the gaseous candidate fuels and have not offered information on costs to modify natural gas burners to burn the candidate fuels. They have further advised that such burner conversions would not be viable and that a new combustion system would be required.

In light of the lack of information on modification costs, the fact that suppliers of burners for the candidate fuels exist and the advice that burner conversion is not viable, we have decided to take the view that there is 100% technical potential to burn the above candidate fuels using new dedicated burners and restrict the economic analysis to that case.

3.4.4. Cost Effective Potential for Candidate Fuel Use

Full detail of the model used to generate the following results and those for the other sectors is given in Appendix 10. Appendix 10 describes the operation of the model in terms of how the results for the glass sector are returned.

The cost effective potential for displacement of the incumbent fuels used for direct heat in the Glass sector was carried out for the following candidate fuels:

- Syngas - waste (Syngas from the gasification of waste)
- Syngas – biomass (from the gasification of waste wood chip)
- Hydrogen (delivered to the site in the form of compressed hydrogen)

The assumptions made for the cost effective potential modelling for the Glass sector are set out in detail in Appendix 3 – Glass Scenario Assumptions. However, the most important assumptions for interpreting the results presented in the sections below are reproduced here.

- In the case of glass melting in the flat and container sub-sectors, it was assumed that 50% of the thermal input (not including electricity consumption by submerged electrodes) would have to continue as natural gas, with the balance being the above listed candidate fuels. This approach follows conversations with British Glass on the ability of the candidate fuels to generate the required temperatures whilst retaining the current melting furnaces, thereby avoiding wider process change. The lower calorific values of syngas and hydrogen, with respect to natural gas, would require the consumptions of larger volumes of candidate fuel in order to achieve the very high temperatures required for melting, leading to larger mass flows through the furnace. It was felt that very large increases in mas flow could not be tolerated without changing the furnace and so the substitution level of candidate fuel was restricted to 50%.
- In the case of the Lehr and Forehearth processes, which are processes requiring lower temperatures and for which the additional mass flow is not considered as big an issue as for glass melting, the incumbent fuel was 100% replaced by the candidate fuel.
- In the case of container glass melting, the current electricity consumption of about 3% is retained in the new technology case and is not displaced by the candidate fuel. This is because this electricity performs a specific role (discussed above) which cannot be provided by the candidate fuel.
- In all new technology cases, back up burners are included such that the thermal requirement can be supplied entirely by natural gas, if needed. This reflects the need for sites to be confident that, in the event of a failure of supply of candidate fuels, they will be able to continue operating as normal.
- In the case where the candidate fuel is syngas and this is supplied by on-site gasification plant, gasification capacity of 130% of the nominal capacity required to supply the syngas demand is assumed necessary. This reflects the need for gasifier operation to continue when some of the capacity is down for cleaning. It is assumed that gasifier capacity is installed in discrete units and at any one time 30% of this capacity will be being cleaned and will not be available.
- In the case where the candidate fuel is syngas and this is supplied by on-site gasification plant, it is assumed that additional electricity consumption equivalent to 3% of the syngas energy yield of the gasifier is incurred. This is the parasitic load of the gasifier and associated plant (see Footnote 151).
- In the case where the candidate fuel is syngas from the gasification of waste, the cost effective potential has been examined for three assumed gate fees to reflect what the operator of the gasifier might receive or have to pay in exchange for taking receipt of the waste to be gasified. These gate fees are: £40/tonne (operator receives payment), £0/tonne and -£40/tonne (operator makes payment). The waste is assumed to be Refuse Derived Fuel (RDF) with a GCV of 13 MJ/kg.

Table 14 Flat Glass Melting – Modelling Results for Syngas- Waste, Syngas – Biomass and Hydrogen

	Fuel Consumption (MWh)	Annual CO_{2e} Emissions (tCO_{2e})	30 year CO_{2e} Emissions (tCO_{2e})
Counterfactual	1,723,825	317,356	8,885,973

	Gate Fee (£/tonne)	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[32]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m) [33]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[34]
Syngas - Waste	40	861,913	-25,857	102,899	3,003,497	134	18	44.60	20.14
	0	861,913	-25,857	102,899	3,003,497	208	216	69.09	32.92
	-40	861,913	-25,857	102,899	3,003,497	297	457	99.03	48.53
Syngas - Biomass	N/A	861,913	-25,857	145,822	4,205,348	255	343	60.62	39.93

---

[32] Excluding cost of carbon

[33] Excluding cost of carbon

[34] Including cost of carbon

	Scenario	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[35]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m) [36]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[37]
Hydrogen	BROWN	861,913	0	-82,042	-2,297,184	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	MIXED	861,913	0	-82,042	-1,779,635	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	GREEN	861,913	0	-217,334	-648,986	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase

---

[35] Excluding cost of carbon

[36] Excluding cost of carbon

[37] Including cost of carbon

	Scenario	CO_{2e} Saving Relative to Counterfactual - 30 Year Appraisal Period (tCO_{2e})	Year in Which New Technology Would Begin to Generate CO_{2e} Savings	Annual CO_{2e} Saving Relative to Counterfactual in 30 years' time (2043) (tCO_{2e})	Year from Which Investment Would Generate CO_{2e} Savings Over 30 year Period Relative to Counterfactual
Hydrogen	BROWN	-2,297,184	Never	-82,042	Never
	MIXED	-1,779,635	Early 2040s	-3,808	~2030
	GREEN	-648,986	2029	112,146	~2017

Table 15 Container Glass Melting – Modelling Results for Syngas- Waste, Syngas – Biomass and Hydrogen

	Fuel Consumption (MWh)	Annual CO_{2e} Emissions (tCO_{2e})	30 year CO_{2e} Emissions (tCO_{2e})
Counterfactual	3,837,426	752,196	20,516,892

New Technol./ Candidate Fuel	Gate Fee (£/tonne)	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[38]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m) [39]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[40]
Syngas - Waste	40	1,861,152	-55,834	251,445	7,304,588	227.0	-100	31.12	14.79
	0	1,861,152	-55,834	251,445	7,304,588	386.0	325	52.87	27.57
	-40	1,861,152	-55,834	251,445	7,304,588	580.0	846	79.45	43.19
Syngas - Biomass	N/A	1,861,152	-55,834	344,131	9,899,778	489.0	600	49.35	34.58

---

[38] Excluding cost of carbon

[39] Excluding cost of carbon

[40] Including cost of carbon

New Technol./ Candidate Fuel	Scenario	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[41]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m)[42]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[43]
Hydrogen	BROWN	1,861,152	0	-147,903	-4,141,296	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	MIXED	1,861,152	0	-147,903	-3,023,739	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	GREEN	1,861,152	0	-440,043	-582,298	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase

---

[41] Excluding cost of carbon

[42] Excluding cost of carbon

[43] Including cost of carbon

	Scenario	CO_{2e} Saving Relative to Counterfactual - 30 Year Appraisal Period (tCO_{2e})	Year in Which New Technology Would Begin to Generate CO_{2e} Savings	Annual CO_{2e} Saving Relative to Counterfactual in 30 years' time (2043) (tCO_{2e})	Year from Which Investment Would Generate CO_{2e} Savings Over 30 year Period Relative to Counterfactual
Hydrogen	BROWN	-4,141,296	Never	-147,903	Never
	MIXED	-3,023,739	2042	21,030	~2027
	GREEN	-582,298	2028	271,413	~2016

Table 16 Container Glass Lehr – Modelling Results for Syngas- Waste, Syngas – Biomass and Hydrogen

	Fuel Consumption (MWh)	Annual CO_{2e} Emissions (tCO_{2e})	30 year CO_{2e} Emissions (tCO_{2e})
Counterfactual	192,000	43,589	948,020

New Technol./ Candidate Fuel	Gate Fee (£/tonne)	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[44]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m) [45]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[46]
Syngas - Waste	40	192,000	-5,760	31,164	627,356	-5.0	-70	-8.18	No subsidy required
	0	192,000	-5,760	31,164	627,356	11.0	-26	17.94	5.67
	-40	192,000	-5,760	31,164	627,356	31.0	27	48.86	21.28
Syngas - Biomass	N/A	192,000	-5,760	40,725	895,081	22.0	2	24.38	12.67

---

[44] Excluding cost of carbon

[45] Excluding cost of carbon

[46] Including cost of carbon

New Technol./ Candidate Fuel	Scenario	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[47]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m)[48]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[49]
Hydrogen	BROWN	192,000	0	-10,034	-553,423	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	MIXED	192,000	0	-10,034	-438,133	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	GREEN	192,000	0	-40,172	-186,270	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase

---

[47] Excluding cost of carbon

[48] Excluding cost of carbon

[49] Including cost of carbon

	Scenario	CO_{2e} Saving Relative to Counterfactual - 30 Year Appraisal Period (tCO_{2e})	Year in Which New Technology Would Begin to Generate CO_{2e} Savings	Annual CO_{2e} Saving Relative to Counterfactual in 30 years' time (2043) (tCO_{2e})	Year from Which Investment Would Generate CO_{2e} Savings Over 30 year Period Relative to Counterfactual
Hydrogen	BROWN	-553,423	Never	-26,548	Never
	MIXED	-438,133	Post 2050	-9,120	Post 2040
	GREEN	-186,270	2029	16,710	~2018

Table 17 Container Glass Forehearth – Modelling Results for Syngas- Waste, Syngas – Biomass and Hydrogen

	Fuel Consumption (MWh)	Annual CO_{2e} Emissions (tCO_{2e})	30 year CO_{2e} Emissions (tCO_{2e})
Counterfactual	192,000	39,468	968,871

New Technol./ Candidate Fuel	Gate Fee (£/tonne)	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[50]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m) [51]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[52]
Syngas - Waste	40	192,000	-5,760	27,042	648,207	12.0	-34	18.40	6.15
	0	192,000	-5,760	27,042	648,207	28.0	10	43.67	18.92
	-40	192,000	-5,760	27,042	648,207	48.0	64	74.57	34.54
Syngas - Biomass	N/A	192,000	-5,760	36,604	915,932	39.0	39	42.44	25.93

---

[50] Excluding cost of carbon

[51] Excluding cost of carbon

[52] Including cost of carbon

New Technol./ Candidate Fuel	Scenario	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[53]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m) [54]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[55]
Hydrogen	BROWN	192,000	0	-14,155	-532,572	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	MIXED	192,000	0	-14,155	-417,283	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	GREEN	192,000	0	-44,293	-165,419	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase

---

[53] Excluding cost of carbon

[54] Excluding cost of carbon

[55] Including cost of carbon

	Scenario	CO_{2e} Saving Relative to Counterfactual - 30 Year Appraisal Period (tCO_{2e})	Year in Which New Technology Would Begin to Generate CO_{2e} Savings	Annual CO_{2e} Saving Relative to Counterfactual in 30 years' time (2043) (tCO_{2e})	Year from Which Investment Would Generate CO_{2e} Savings Over 30 year Period Relative to Counterfactual
Hydrogen	BROWN	-532,572	Never	-22,412	Never
	MIXED	-417,283	Late 2040s	-4,984	Post 2030
	GREEN	-165,419	2029	20,846	~2018

From the results presented in the table above it can be seen that for the gate fee assumptions made (£40/tonne, £0/tonne and -£40/tonne) and for a commercial discount rate of 12%, for all but one process in the glass sector the use of syngas from the gasification of waste is more expensive than the counterfactual. The exception is for the Lehr process with the gate fee assumption of £40/tonne. This is because the counterfactual for the Lehr process is, itself, relatively expensive because it involves the consumption of a significant quantity of electricity which is a relatively expensive fuel. This makes the consumption of syngas from waste slightly cheaper than the counterfactual over the 30 year assessment period and a commercial discount rate of 12%.

The implied subsidy to close the cost gap between syngas-waste and the counterfactual is highest in flat glass melting at £48/MWh. This is explained by the fact that this process is entirely natural gas fired, unlike the other processes which included either electricity or fuel oil, which are more expensive than natural gas.

For some syngas-waste scenarios while the new technology case is more expensive than the counterfactual for the commercial discount rate of 12% the new technology is actually cheaper than the counterfactual for the social discount rate of 3.5%. This occurs for cases where the gate fee assumption is either £40/tonne or £0/tonne. This is due to the fact that for these gate fee assumptions there is a positive or zero cash flow for fuel costs over each year of the appraisal period (operator either receives payment for receiving waste or neither pays nor receives anything for receiving the waste), while in the counterfactual there is a negative cash flow for fuel costs (operator has to pay for its natural gas and fuel oil). These cash flows occur over every year of the appraisal period. For the lower social discount rate the positive fuel cash flows are discounted less than for the higher private discount rate, leading to the former managing to more than balance the discounted capex, which occurs upfront and at year 20, rather than over every year of the appraisal period, thereby returning a cash saving relative to the counterfactual. This effect disappears when the operator has to start paying for its fuel, as is the case with a gate fee of -£40/tonne or when purchased biomass is being gasified.

For all hydrogen scenarios examined, there is an increase in CO_{2e} emissions relative to the counterfactual over the 30 year period starting now. In order for the Mixed hydrogen scenario to produce CO_{2e} savings over the 30 year assessment period, the application of CCS to SRM would have to be brought forward in time. Likewise, the electricity grid would have to decarbonise more quickly in order for the Green hydrogen scenario to produce CO_{2e} savings over the 30 year assessment period.

In order to put the hydrogen scenarios into context, further information is supplied at the bottom of Table 15, Table 16 and Table 17 for each of the Brown, Mixed and Green hydrogen scenarios. This additional information shows the first year in which each scenario would generate annual CO_{2e} savings relative to the counterfactual, the annual saving that would be generated at the end of a 30 year assessment period which starts now, i.e. the annual savings in 2043 and the year in which the hydrogen project would have to be invested in if it were to generate net CO_{2e} savings over a 30 year assessment period. For the Brown scenario, CO_{2e} savings are never achieved relative to the counterfactual. Annual savings over the counterfactual would begin in the late 2040s or later for the Mixed scenario and in the late 2020s for the Green scenario. Net CO_{2e} savings over a 30 year assessment period would occur for the Green scenario if investment was made in the period 2016-2018, while for the Mixed scenario, investment would have to begin much later if net CO_{2e} savings were to be achieved over a 30 year period.

4. Characteristics of Iron and Steel Sector

4.1. Iron and Steel Sector – Sub-sectors and Direct Heat Consuming Processes

4.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat

The Steel sector is comprised of the following sub-sectors:

- Primary Production – Blast Furnace/Basic Oxygen Steelmaking (BOS) Route
- Primary Production – Electric Arc Furnace (EAF) Route
- Downstream Production

The relative importance of these sub-sectors in terms of the quantity of fuel consumed for the generation of direct heat is summarised in Table 18. The data for the Downstream Production sub-sector applies to downstream activities at both primary steel production sites and non-primary steel production sites, and includes data for rolling mills, tube mills, wire and coating plants.

Table 18 Iron and Steel Sector Summary (Data for 2013 supplied by UKSA) Data presented as received

Sector/Sub-sector	Annual Fuel Consumption for All Heat (MWh)	Annual Fuel Consumption for Direct Heat (MWh)
Blast furnace/BOS steelmaking	Not available	56,326,328
EAF Steelmaking	Not available	893,816
Downstream production	Not available	2,096,098
Iron and Steel (Total)	67,921,055[56]	59,316,242[57]

Overall, about 87%[58] of the fuel used to generate heat in the Steel sector is used for the generation of heat supplied direct to process.

---

[56] The fuel for indirect heat includes the double of counting of some energy, due to the consumption of by product gases such as blast furnace gas, coke oven gas and BOS gas for the generation of steam at CHP stations, which is subsequently consumed by steam producing processes. Unlike the case for direct heat, information is not available to allow this double counted energy to be removed. This would require knowledge of the quantity of by-product gas consumed in the CHP and the quantities of power and steam generated by the CHP. This information is not available to the authors.

[57] Double counting of energy removed where appropriate. See section 4.5

[58] The true figure will be higher for the reasons given above.

4.1.2. Direct Heat Consuming Processes

The main direct heat consuming processes carried out in the Steel sector are given in Table 19.

Table 19 Direct Heat Consuming Processes in the Steel Sector (Data for 2013 provided by UKSA)

Direct Heat Consuming Process	**Annual Fuel Consumed for Generation of Direct Heat (MWh)**	**Temperature Requirements of Process (ºC)**	**Characteristics of Heat – Hot Air Composition**
Coke production (Blast Furnace)	3,365,837	1000	No specific requirements
Sinter production (Blast Furnace)	2,789,395	500	No specific requirements
Blast Furnace	47,792,353	1400	Needs to generate a reducing atmosphere, but not strict cleanliness requirements
Basic Oxygen Steelmaking (Blast Furnace)	630,568	1400	Should be clean
Hot rolling-reheating etc. (Blast Furnace)	1,748,175		Usually should be clean
Steelmaking including secondary (EAF)	625,106	Various	Usually should be clean
Casting (EAF)	39,038		Usually should be clean
Hot rolling – reheating Furnaces (EAF)	229,672	950/1250	Usually should be clean
All heating processes(Downstream)	2,096,098	Various	Usually should be clean
Total	59,316,242[59]		

Overall, a little over 80% of fuel consumed for the generation of direct heat is consumed in the blast furnace where molten iron is produced from the reduction of iron ore. Other processes consuming direct heat and the nature of the process are described below.

The BOS process is the major modern process for making bulk steels. Apart from special quality steels (such as stainless steel), all flat products in the UK, and long products over a certain size, are rolled from steel made by the BOS process.

---

[59] Double counting of energy removed where appropriate. See section 4.5

The key component in the BOS is the Basic Oxygen Converter, however before this process can begin a blast furnace is required to create a charge of molten iron. The raw materials for producing molten iron are iron ore, coking coal and fluxes (materials that help the chemical process) - mainly limestone.

The coal and ore arrives by sea in very large ships and is off-loaded at deep-water harbours close to the steelworks that use it. The iron ores arrive in a number of forms: lumps of ore in the form in which they were mined; fine-sized iron ores; and pellets - fine ores which have been processed to stick together to form hard spheres of iron ore. The coals and ores are transported by conveyor belt or rail to stockyards where they are stored and carefully blended.

Blended coal is first heated in coke ovens to produce coke; the main fuel used for heating the coke ovens is coke oven gas (81.8%) with the balance of the heat provided by Blast Furnace gas (18.2%). This process is known as carbonisation. The gas produced during carbonisation is extracted and used for fuel elsewhere in the steelworks. Other by-products (such as tar and benzole) are also extracted for further refining and sale. Once carbonised, the coke is pushed out of the ovens and allowed to cool.

Fine-sized ore is first mixed with coke and fluxes and heated in a sinter plant, the main fuel used for heating the sinter ovens is Coke (88.3%) with the balance of the heat provided by Coal (5.2%) and some Natural Gas (2.3%) and Coke oven gas (4.2%). This is a continuous moving belt on which the coke is ignited. The high temperatures generated fuse the ore particles and fluxes together to form a porous clinker called sinter. The use of sinter in the blast furnace helps make the iron making process more efficient.

Iron ore lumps and pellets, coke, sinter and extra flux are carried to the top of the blast furnace on a conveyor or in skips and then tipped, or charged, into the furnace. Hot air (900°C is blasted into the bottom of the furnace through nozzles called tuyeres, and heat is produced using coke as the main fuel (60%), coal (~31%) and the balance being blast furnace gas (8%) and small amounts of coke oven gas and natural gas used in the stoves to heat the blast air. The oxygen in the air partially combusts with the coke to form carbon monoxide gas, and this generates heat. Frequently oil or coal is injected with the air, which enables less (relatively expensive) coke to be used. The carbon monoxide flows up through the blast furnace charge and removes oxygen from the iron ores on their way down, thereby leaving iron. The heat in the furnace melts the iron, and the resulting liquid iron (known as hot metal) is tapped at regular intervals by opening a hole in the bottom of the furnace and allowing it to flow out. This iron has a relatively high content of carbon, which must subsequently be reduced in order for ductile steels to be produced. The fluxes combine with the impurities in the coke and ore to form a molten slag, which floats on the iron and is also removed (tapped) at regular intervals.

The hot metal flows into torpedo ladles. These are specially constructed railway containers which transport iron, still in liquid form and with a relatively high carbon content, to the steel furnace (BOS). The BOS vessel is first tilted to allow materials to be tipped into it (charged). Scrap steel is first charged into the vessel, followed by hot metal (liquid iron) from the blast furnace. A water-cooled lance is lowered into the vessel through which very pure oxygen is blown at high pressure. The oxygen combines with the carbon, and with other unwanted elements, separating them from the metal, leaving steel. The process by which oxygen combines with carbon is exothermic and this supplies a proportion of the heat required by the BOS process. Other fuels used to supply heat to the BOS process include coke oven gas (39%), electricity (40%) and natural gas (21%). Oxygen Lime-based fluxes (materials that help the chemical process) are charged, and they combine with the "impurities" to form slag. The main gas formed as a by-product of the oxidation process is carbon-monoxide, and this is sometimes collected for use as a fuel elsewhere in the works. This is known as Basic Oxygen Steelmaking Gas (BOS Gas).

A careful balance between the amounts of hot metal and scrap charged into the converter is maintained as a means of controlling the temperature and to ensure that steel of the required specification is produced. After a sample has been taken to check that the composition of the steel is correct, the vessel is again tilted to allow the molten steel to flow out. This is known as tapping. The steel is tapped into a ladle, in which secondary steelmaking frequently takes place. During tapping small quantities of other metals and fluxes are often added to control the state of oxidation and to meet customer requirements for particular grades of steel.

Finally the vessel is turned upside down and the slag tipped out into a container. Steelmaking slag is sometimes recycled to make road building materials.

The modern BOS vessel makes up to 350 tonnes of steel at a time, and the whole process takes about 40 minutes.

Re- Heating – This takes place in furnaces that are fired by a range of burner types. The main fuel used for melting is Coke oven gas (47%) followed by natural gas (32%) and BOS gas (19%).

4.2. Iron and Steel Sector – Characteristics of Direct Heat Consuming Processes

4.2.1. Types of Fuel Used

This Section sets out the relative importance of each direct heat consuming process in terms of fuel consumption.

Table 20 summarises the types of fuel currently used in each process.

Table 20 Fuels Used for Direct Heat in the Steel Sector (Data for 2013 supplied by UKSA)

Process	Natural Gas	Coal	Coke	LPG	Blast Furnace gas	Coke Oven Gas	BOS gas	Electricity
Coke production (Blast Furnace)					18.2%	81.8%		
Sinter production (Blast Furnace)	2.3%	5.2%	88.3%			4.2%		
Blast Furnace	0.4%	30.6%	60.1%		7.8%	0.8%	0.2%	
Basic Oxygen Steelmaking/Casting (Blast Furnace)	21.1%					39%		39.9%
Hot rolling-reheating etc. (Blast Furnace)	32.1%				1.9%	47%	19%	
Steelmaking including	16.3%	2.6%	13%	0.6%				67.5%

Process	**Natural Gas**	**Coal**	**Coke**	**LPG**	**Blast Furnace gas**	**Coke Oven Gas**	**BOS gas**	**Electricity**
secondary (EAF)								
Casting (EAF)	100%							
Hot rolling – reheating Furnaces (EAF)	100%							
All heating processes(Downstream)	100%							
Total	**5.54%**	**24.86%**	**52.19%**	**0.01%**	**7.51%**	**8.01%**	**0.85 %**	**1.04%**

Currently, Coke constitutes a very large majority of total fuel consumption for the generation of direct heat (52%). The second most used fuel is Coal (25%) followed by Coke Oven Gas (8%).

Currently 16% of fuel for direct heat is supplied by the process gases of coke oven gas, blast furnace gas and BOS gas in the steel sector.

4.2.2. Fuel Costs

Fuel costs paid by industry vary according to demand. This is demonstrated in DECC's Quarterly Energy Prices document, where, for consumers of fuels, prices are presented according to three sizes of consumer (small, medium and large).

Blast furnace/BOS steelmaking – The main fuel used in Blast Furnace/BOS steelmaking is Coke. Of the three sites (TATA Scunthorpe, TATA Port Talbot and SSI Teesside) undertaking this process, the average consumption of the fuel Coke is 11,231,782 MWh, which is assumed to be equivalent to over 15 million MWh of coal, placing each site firmly in the 'large' category, implying a price for coal of 1.09 p/kWh (excl. CCL[60]).

EAF Steelmaking - In the EAF steelmaking sub-sector the average fuel for heat consumption is a little over 446,907 MWh per site with the main fuel used .being electricity This would place the average EAF steelmaking site in the 'extra-large' category, paying 6.76 p/kWh (excl. CCL).

Downstream production – In the Downstream production, the main fuel consumed for the generation of direct heat is natural gas, but the average consumption of this fuel at the site level is unknown.

4.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions

The specific energy consumption and specific CO_{2e} emissions for each of the seven main direct heat consuming processes, for which industry throughput data is available, are set out in

---

[60] Note, Under the Metallurgical/Mineralogical CCL exemption, from April 2014 CCL will no longer be changed on energy consumed in this process or any of the other processes carried out in the Iron and Steel sector.

Table 21. The unit of throughput is in terms of tonnes of product emerging from the process. Therefore, in the case of the process ‘Coke production’ the throughput is in units of tonnes of dry coke produced and for ‘Blast Furnace’ the throughput is in terms of tonnes of hot metal.

Table 21 Specific Energy Consumption and CO2e Emissions of Main Direct Heat Consuming Processes in the Steel Sector (From data provided for 2013 by UKSA)

Direct Heat Consuming Process	Specific Energy Consumption (MWh/tonne)[61]	Specific CO_{2e} Emissions (tCO_{2e}/tonne)
Coke production (Blast Furnace)	0.795	0.118
Sinter production (Blast Furnace)	0.248	0.100
Blast Furnace(includes coal prep/Stoves/main shaft)	4.827	1.832
Basic Oxygen Steelmaking/Casting (Blast Furnace)	0.055	0.017
Steelmaking including secondary (EAF)	0.682	0.304
Casting (EAF)	0.053	0.010
Hot rolling – reheating Furnaces (EAF)	0.543	0.101

From this it is clear that Blast Furnace, (which includes coal preparation, stoves and main shaft), is easily the most energy and CO_{2e} intensive of the processes.

4.2.4. Heat Load Factors

This requires knowledge of the number and capacity of burners, which is currently unknown for the Steel sector as a whole.

4.3. Types of Burner Used

The EAF sites supplying data to this study have supplied information on burner types. These have not been used in the analysis as the analysis has been confined to the blast furnace process and this process is not carried out at EAF sites. The rationale for confining the analysis to the blast furnace process is explained in the last paragraph of Section 4.4.1.However, for the record, it is instructive to note the following salient points about burners used at EAF sites producing stainless steel:

- The Argon Oxygen Decarbonisation (AOD) vessel[62] requires preheating and this uses burners with recuperators with individual capacities in the region 2.9 to 5.9 MWth.

---

[61] Double counting of energy removed where appropriate. See section 4.5

- Ladle heaters utilise cold air burners with capacities in the region of 4.1 MWth.
- There are a range of other burners used to heat slab, dry slab and dry DC arc vessels with capacities in the range from about 0.3 MWth to 3 MWth.

4.4. Technical Potential for Candidate Fuel Consumption and Barriers

4.4.1. Suitability of Candidate Fuels

Wood charcoal can be the source of carbon required to reduce iron ore and the heat required to produce hot, liquid metal in the blast furnace. This charcoal can be supplied either in the main charge loaded at the top of the blast furnace or supplied to the blast furnace instead of pulverised coal injection (PCI) at the tuyeres, at the bottom of the blast furnace. In addition to the obvious CO_{2e} abatement resulting from the displacement of coal derived coke by charcoal, other benefits result from charcoal use, including lower levels of sulphur and phosphorous inclusion in the hot metal and lower ash content, leading to less slag generation, although this last benefit depends upon the origin of the biomass used to make the charcoal.

PCI is used to reduce the coke rate (the consumption of coke per unit of hot metal produced). As coke is expensive, this reduces process costs and can also increase the productivity of the blast furnace.

Until the process of coke making was developed in the 1700s, charcoal from wood was the sole fuel used in the reduction of iron ore. However, the physical properties of charcoal limit its functionality in large blast furnaces when included in the main charge, especially due to its structural weakness and low compression resistance, which prevents it from supporting the iron ore burden in larger blast furnaces[63]. This is one of the reasons why coke came to predominate as the carbon source in the blast furnace as the greater strength of coke compared to charcoal allowed larger shafts to be used, resulting in higher levels of productivity. Notwithstanding these strength limitations, charcoal is used widely in smaller blast furnaces in Brazil where the limitations on mechanical strength are not a significant issue. Brazil's largest charcoal fired blast furnace produces up to 1.5 Mt of hot metal per year and, overall, charcoal supplied 31% of Brazil's iron and steel industry's energy requirement in 2010[64]. It is also reported that there are 163 charcoal based blast furnaces operating in Brazil[65].

It is understood that there are 7 blast furnaces operating in the UK with capacities ranging from 1.1 to 3.1 Mt hot metal per year. As there is uncertainty regarding the capacity below which charcoal could be used in the main blast furnace change, it will be assumed that all UK blast furnaces are too large for it to be technically possible to use significant amounts of charcoal in the main blast furnace change. However, this point needs to be followed-up in more detail as it may be possible that a proportion of the UK's blast furnace capacity could be susceptible to significant use of charcoal in the main blast furnace charge. It is also worth noting that charcoal

---

[62] AOD vessel is where liquid steel is refined by controlling the carbon, sulphur and alloy content. It is used in the manufacture of stainless steel and other high grade alloys.

[63] http://www.iea-coal.org.uk/documents/82861/8363/CO2-abatement-in-the-iron-and-steel-industry,-CCC/193 (Visited 24/10/14)

[64] http://www.carbontrust.com/news/2014/05/industrial-renewable-heat (Visited 24/10/14)

[65] Revista de Metalurgia, 49 (6) p. 458-468

with higher strength is under development[66] which could overcome the present issues with low charcoal mechanical strength.

Given the above, the use of pulverised charcoal instead of PCI would appear to offer more certain potential for charcoal use, as the mechanical strength limitation of charcoal would not present itself as an issue for this particular application.

The opportunities to use more of the process gasses arising at integrated steel works to generate direct heat were considered. If process gasses such as coke oven gas, blast furnace gas or BOS gas are flared and other fuels like natural gas are used to meet direct heat demand on the same site, overall emissions could be reduced if the process gas, instead of being flared, was used to displace the other fuels. Information from the industry indicates that, in the case of coke oven gas and blast furnace gas, where there is demand for heat or demand from on-site power plant, flaring of these gases is low, i.e. it is put to a useful purpose in one of these two applications. If there is flaring there is a tendency for this to coincide with low demand for heat from processes that might otherwise use the process gas or power plant failure or maintenance. Information from industry indicates a greater tendency to flare BOS gas, but for reasons to do with the suitability of BOS gas properties for other applications.

Overall, only about 6.5% of fuel consumed at the sites supplying data for this study was natural gas, LPG or electricity, with the balance being coal, coke and process gases associated with primary steel production (COG, BFG and BOS gas). The overwhelming majority of fuel consumption is associated with the blast furnace (80%) and this is why the technical and economic potential evaluated in this study concentrates on the substitution of coal or coke in the blast furnace with renewable fuel.

4.4.2. Technical Barriers to Candidate Fuel Use

Use of charcoal in the main charge of large blast furnaces is limited by its low mechanical strength. Use of charcoal on any significant scale would also prove a logistical challenge. The operation of planting, growing, harvesting and transforming into charcoal and transporting to UK integrated steel works would require the development of a large sustainable transnational supply chain, the sustainability of which, might be difficult to guarantee. The use of charcoal in blast furnaces may also reduce the productivity which could present an additional cost to the industry.

4.4.3. Technical Potential for Candidate Fuel Use

There is no relevant data from sector in the UK. However, the use of charcoal in both the blast furnace main change and as a substitute for pulverised coal injection (PCI) injected through the tuyeres has been trialled internationally. The technical potential for charcoal substitution in the main blast furnace charge is less certain than the technical potential for charcoal to displace PCI, as charcoal does not have the mechanical strength to support the iron ore charge in larger blast furnaces.

As there is uncertainty about whether the size of UK blast furnaces could support the substitution of coke by charcoal in the main blast furnace charge, the technical potential for charcoal is considered to be confined to the substitution of pulverised coal by pulverised

---

[66] http://www.unido.org/fileadmin/user_media/Services/Energy_and_Climate_Change/Energy_Efficiency/Renewables_%20Industrial_%20Applications.pdf (Visited: 24/10/14)

charcoal. Charcoal injection rates of up to 200 kg/thm[67] have been achieved, reducing CO_{2e} emissions from the blast furnace by 28% by displacing pulverised coal injection (PCI). However, at these replacement rates there is a reported reduction of 10% in the productivity of the blast furnace[68]. The cost effective potential for complete replacement of PCI with pulverised charcoal is therefore considered in 4.4.4. It is assumed that the energy contained in the displaced PCI must be exactly replaced by the energy contained in charcoal.

In order to reflect possible industry aversion to any perceived risk associated with a complete substitution of pulverised coal by pulverised charcoal, two modelling scenarios have been run, one with all pulverised coal displaced by pulverised charcoal and one with 50% of pulverised coal substituted by pulverised charcoal. More detailed assumptions behind this scenario are set out in detail in Appendix 4.

---

[67] thm = tonne hot metal

[68] 1st Spanish National Conference on Advances in Materials Recycling and Eco – Energy

4.4.4. Cost Effective Potential for Candidate Fuel Use

4.4.4.1. Replacement of Pulverised Coal Injection by Pulverised Charcoal

Table 22 Blast Furnace for Hot Metal Production -Modelling Results for Substitution of 100% of PCI with Pulverised Charcoal

	Fuel Consumption (MWh)	Annual CO_{2e} Emissions (tCO_{2e})	30 year CO_{2e} Emissions (tCO_{2e})
Counterfactual	51,989,971	17,107,617	496,120,902

New Technol./ Candidate Fuel	Gate Fee (£/tonne)	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[69]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m) [70]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[71]
100% of PCI with Charcoal	N/A	15,908,931	0	4,588,136	132,732,984	12,978	36,623	97.8	114.75
50% of PCI with Charcoal	N/A	15,908,931	0	2,294,068	66,527,963	7,991	22,414	120.1	143.02

---

[69] Excluding cost of carbon

[70] Excluding cost of carbon

[71] Including cost of carbon

From Table 22 it can be seen that the substitution of PCI with pulverised charcoal is an expensive abatement measure, even with the assumption that there is no capital expenditure required for additional fuel storage, handling and processing facilities[72]. If additional capital expenditure were to be including in the modelling to cover these items then the measure would become even more expensive. The relative expense of this opportunity relative to the counterfactual is driven by the high price of charcoal, which is assumed to have a current price of approximately £100/MWh, compared with the fuel it is replacing, pulverised coal, which is assumed to have a current price of approximately £11/MWh. The present value of CO_{2e} savings delivered by a 100% substitution of PCI with charcoal is £784 m over the 30 year assessment period, while the present value of the additional fuel costs is about thirteen times larger. This means that the value of the CO_{2e} savings is many times less that the additional fuel cost.

4.5. Basis of Energy Accounting

The figures presented in Table 18, Table 19 and

Table 21 are compiled on a primary energy accounting basis. The data received from UK Steel were provided on a delivered energy basis, i.e. the energy inputs at the point of delivery were counted.

However, three primary processes considered in this Iron and Steel study take primary fuel, transform some of it to heat and transfer some of it into other, manufactured fuels which may be recycled back in the primary process or consumed in a secondary process. These primary processes are: Coke production, Blast Furnace and Basic Oxygen Steelmaking. The primary fuel in and the manufactured fuels out are summarised in Table 23.

Table 23 Relationship between primary fuel in, manufactured fuel out, delivered energy in and delivered energy counted

Process	**Primary Fuel In**	**Delivered Fuel In**	**Manufactured Fuel Out**	**Delivered Energy Counted**	**Delivered Energy Double Counted**
Coke Production	Coking coal	Coking coal, COG, BFG	Coke, COG	COG, BFG	BFG
Blast Furnace	Coal, NG	Coke, coal, NG, BFG, COG, BOS gas	BFG	Coke, coal, NG, BFG, COG, BOS gas	BFG, BOS gas
Basic Oxygen Steelmaking	NG, electricity	NG, COG, electricity	BOS gas	NG, COG, electricity	None

---

[72] It was not possible within the time frame of this study to source capital costs for any additional charcoal storage, handling and processing facilities.

In Coke Production energy in COG comes from coking coal. Since coking coal has not been counted in Coke Production, if COG is counted as consumed in any other process there is no double counting.

In a blast furnace, the energy in BFG comes from the coal and coke inputs to the blast furnace. Since coal and coke are counted in Blast Furnace, if BFG is counted in any process the energy in that BFG is double counted.

In Basic Oxygen Steelmaking, the energy in the BOS gas comes from the burning of the carbon dissolved in the liquid iron by blowing oxygen through the liquid iron. This carbon in the liquid iron comes from the coal and coke inputs to the blast furnace. Since coal and coke are counted in the Blast Furnace, if BOS gas is counted in any process then the energy in that BOS gas is double counted.

Therefore, the figures in Table 18, Table 19 and

Table 21 have been derived by taking the delivered energy figures supplied for each process by UK Steel and discounting any consumption of BFG or BOS gas consumption.

4.6. Comparison with DUKES Data

The data presented in this section for the Iron and Steel sector is from 2013. In 2013 blast furnaces at all three integrated steel sites[73] were operating.

At the time of writing, only data for 2012 was available in DUKES for comparison. The blast furnace at SSI Teesside operated for only part of 2012. Table 1.1 of DUKES 2013 shows final energy consumption of 1,196 ktoe for Iron and Steel in 2012. The same table shows net consumption of blast furnaces and coke ovens of 2,184 ktoe in the “Transformation” section and a further 761 ktoe in the “Energy Industry Use” section. Assuming that there is no double counting of energy in the Transformation, Energy Industry Use and Final Consumption sections of Table 1.1, a total energy consumption of 4,141 ktoe, or 48.4 TWh is implied for the Iron and Steel sector for 2012, a year when the SSI blast furnace was only partially operational. This compares with a total in this study of 59.3 TWh in 2013, a year when all blast furnaces were operational.

---

[73] TATA Port Talbot, TATA Scunthorpe and SSI Teesside

5. Characteristics of Ceramics Sector

5.1. Ceramics Sector – Sub-sectors and Direct Heat Consuming Processes

5.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat

The Ceramics sector is comprised of the following sub-sectors:

- Heavy Clay (bricks, tiles, etc.)
- Refractories (insulation materials)
- Whitewares (sanitary ware, table ware)
- Materials (materials for a wide range of specialist applications, e.g. electro-ceramics)

The relative importance of these sub-sectors in terms of the quantity of fuel consumed for the generation of direct heat is summarized in Table 24.

Table 24 Ceramics Sector Summary (Data for 2012 supplied by BCC). Data presented as received

Sector/Sub-sector	Annual Fuel Consumption for All Heat (MWh)	Annual Fuel Consumption for Direct Heat (MWh)
Ceramics	3,970,671	3,886,805
Heavy Clay		2,582,935
Refractories		431,934
Whitewares		678,647
Materials		193,289

Overall, about 98% of the fuel used to generate heat in the Ceramics sector is used for the generation of heat supplied direct to process.

It should be noted that he data supplied by BCC is for the ceramic sites within the Ceramics Climate Change Agreements (CCAs). The fuel consumed at some refractory manufacturers that do not fire their products before delivery to the final customer, are not included in the above data, as inclusion in the CCA requires firing at the site. These refractory products are fired in-situ in the final application, e.g. liquid iron crucible. However, the refractor manufacturer does have to dry the green component before delivery to the customer. This requires fuel consumption which is not captured in the above data. It is estimated by BCC that including the fuel for this refractory drying would increase the fuel consumed by the Refractories sub-sector shown in Table 24 by 10-15%.

The ceramics sector can also be considered to include ceramic power supplies, which are used to make the products made by the above mentioned sub-sectors. Many of these suppliers consume fuel only for drying and so are not included in the above data. The Kaolin and Ball Clay (KaBCA) industry, which makes ceramic powers and incurs significant fuel consumption for power drying, has a CCA. For information, in 2008, about 528,000 MWh of fuel was consumed at kaolin and ball clay sites in the KaBCA CCA. However, some of this fuel will have been consumed for the generation of electricity in CHP and so only a portion of this 528,000 MWh can be considered associated with drying. In addition to the kaolin and ball clay CCA sites there are other sites producing ceramic powders which are neither in the ceramics CCA nor the kaolin and ball clay CCA and so the above data understates fuel consumption for direct heat in respect of these sites.

5.1.2. Direct Heat Consuming Processes

The main direct heat consuming processes carried out in the Ceramics sector are given in Table 25.

Table 25 Direct Heat Consuming Processes in the Ceramics Sector (Data for 2012 supplied by BCC)

Direct Heat Consuming Process	Annual Fuel Consumed for Generation of Direct Heat (MWh)	Temperature Requirements of Process (ºC)	Characteristics of Heat – Hot Air Composition
Firing (all sub-sectors)	3,275,347	1100 (up to 1750 in refractories)	Must be clean
Drying (all sub-sectors)[74]	549,624	200-220	Must be clean
Spray Drying (Refractories and Whitewares)	61,834	650	Must be clean
Total	**3,886,805**		

Overall, about 84% of fuel consumed for the generation of direct heat is for Firing. Other processes consuming direct heat and the nature of the process are listed below:

Firing – all Ceramic products require firing in kilns at high temperature in order for the full strength of the ceramic component to be developed. Over 94% of the direct heat comes from burning natural gas (100% for Whitewares), with the remainder coming from LPG (1.7%), gas oil (1.3%), fuel oil (0.9%), coal (0.7%) and coke (0.5%).

Drying – all Ceramic products require drying to remove excess moisture from the product before firing, otherwise the product may crack during firing. Waste heat from the firing kilns is usually used to support this. The other sources of heat supporting waste heat utilisation for drying are combustion of natural gas (96%), with the remainder coming from LPG (1.5%), gas oil (1.0%), fuel oil (0.7%), coal (0.8%) and coke (0.5%).

---

[74] Note that fuel consumed for generating heat for drying quoted in this table is additional to the heat already consumed for drying which is recovered from the firing process. At some sites, the heat requirement for drying is substantially or completely met by recovered heat from firing. Therefore, the actual thermal requirement for the drying process is substantially higher than that suggested by Table 25.

Spray Drying – this is used in the Refractories and Whitewares sectors. The process mixes the material in liquid form with hot air and sprays it into an atomiser where the water evaporates leaving a powder which is then formed and fired. This process has been widely used in whitewares since the 1950s and for more refined and advanced ceramic materials. Natural gas is the only fuel used for this (100%).

5.2. Ceramics Sector – Characteristics of Direct Heat Consuming Processes

5.2.1. Types of Fuel Used

This Section sets out the relative importance of each direct heat consuming process in terms of fuel consumption.

Table 26 summarises the types of fuel currently used in each process.

Table 26 Fuels Used in Direct Heat Consuming Processes in Ceramics Sector (Data for 2012 provided by BCC)

Process	**Natural Gas**	**LPG**	**Gas Oil**	**Fuel Oil**	**Coal**	**Coke**
Firing (all sub-sectors)	94.8%	1.7%	1.3%	0.9%	0.7%	0.5%
Drying (all sub-sectors)	95.7%	1.5%	1.0%	0.7%	0.8%	0.5%
Spray Drying (Refractories and Whitewares)	100%	0%	0%	0%	0%	0%
Total	**95.0%**	**1.7%**	**1.2%**	**0.9%**	**0.7%**	**0.5%**

Currently, natural gas constitutes a very large majority of total fuel consumption for the generation of direct heat (95%). The second most used fuel is LPG (1.7%) followed by Gas Oil (1.2%).

The sector has used both mine gas and landfill gas in brick production in the past but the sites doing this have either closed or have chosen to burn landfill gas to generate electricity, as the economics favour electricity generation.

5.2.2. Fuel Costs

Fuel costs paid by industry vary according to demand. This is demonstrated in DECC’s Quarterly Energy Prices document, where, for consumers of fuels, prices are presented according to three sizes of consumer (small, medium and large).

Owing to the preponderance of natural gas consumption in the Ceramics sector, the size categories and fuel prices pertaining to natural gas are referred to here.

The average fuel consumption for heat in the Ceramics sector is estimated to be almost 30,000MWh per site. This would place the average site in the ‘large’ category, paying 2.239 p/kWh (excl. CCL, 2012 prices).

5.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions

The following tables show the specific energy consumption and specific CO_{2e} emissions for each of the three main direct heat consuming processes set out in Table 27. The unit of throughput is in terms of tonnes of product emerging from the process.

Table 27 Specific Energy Consumption of Main Direct Heat Consuming Processes in Ceramics Sector (Data for 2012 provided by BCC)

Direct Heat Consuming Process	Specific Energy Consumption (MWh/tonne)	Specific CO_{2e} Emissions (tCO_{2e}/tonne)
Firing (all sub-sectors)	0.796	0.151
Drying (all sub-sectors)	0.134	0.025
Spray Drying (Refractories and Whitewares)	0.418	0.077

From this it is clear that Firing is the most energy intensive and CO_{2e} intensive process. Although spray drying is a heat intensive process, it is a relatively small consumer of fuel in absolute terms.

5.2.4. Heat Load Factors

The Heat Load Factors we report here are ‘fuel for direct heat load factors’, as the information we have received from sectors is based on quantified fuel consumption for the generation of heat rather than quantified consumption of heat.

Direct heat load factors are calculated as follows:

$$\frac{\text{Fuel Consumed in Process (MWh)}}{Capacity\ of\ Heat\ Generating\ Technology\ (MW) \times 8760\ hrs}$$

This gives an indication of the extent to which the capacity to generate heat is utilised over the course of a year. This requires knowledge of the number and capacity of burners, which is currently unknown for Ceramics. Owing to the large fuel consumption in the heavy clay sub-sector relative to the other sub-sectors, we have undertaken cost effective analysis for heavy clay. We have assumed a heat load factor of 90% which, when taken with the fuel consumption for the two main processes in heavy clay (drying and firing) gives the approximate burner capacities in Table 28.

Table 28 Estimated Burner Capacity for Two Direct Heat Consuming Processes in Ceramics (Determined using data provided by BCC)[75]

Sub-sector	Implied Total Burner Capacity (MW)	Annual Fuel Consumption (MWh)	Assumed Load Factor (%)
Heavy Clay (Firing)	277	2,187,588	90
Heavy Clay (Drying)	50	395,347	90

5.3. Types of Burner Used

More work required to ascertain.

5.4. Technical Potential for Candidate Fuel Consumption and Barriers

5.4.1. Suitability of Candidate Fuels

The largest area of direct heat use in Ceramics by some way is Firing and, indeed, the waste heat from this is further used in the Drying process. As direct heat is delivered to these processes via burners, the relevant candidate fuels are assumed to be either gaseous or pulverised biomass.

5.4.2. Technical Barriers to Candidate Fuel Use

The following technical barriers exist in respect of each of the candidate fuels being considered:

Biogas – Raw biogas directly from an anaerobic digester will contain hydrogen sulphide and other acid gases that may have implications for oven components. As such biogas would have to be cleaned-up before it could be combusted. Cleaned biogas would still be dilute from the point of view of methane content and would contain CO_{2e} in the range 30-40%. This means that the calorific value of cleaned biogas is significantly lower than natural gas. Consequently, for the same burner power to be attained, burner modifications would be needed to allow a much higher volume throughput of fuel gas. The increased mass flow may also have implications for the way heat is transferred. Cleaned biogas would burn with a lower flame temperature than natural gas. This will place limits on the extent to which cleaned biogas can displace natural gas unless complete burner replacement occurs. (Upgraded biogas – where CO_{2e} is removed – could be substituted one for one with natural gas. This is a proven technology.).

As discussed in Section 2.6.2, the supply of biogas for generation of direct heat in industry is assumed to be limited. However, BCC view biogas for direct heat applications as a key fuel swap opportunity, integral to their decarbonisation strategy. This raises a question about whether biogas used for the generation of electricity or injected to the gas grid, and used for

---

[75] If the assumed load factor is too high, then this would lead to and underestimate of the total burner capacity, and vice versa. This would, therefore, lead to an underestimate for the total burner replacement cost in the cost effective modelling.

heating applications that could be decarbonised by other means, could be better used in other ‘hard to decarbonise’ applications such as ceramic firing.

Hydrogen – The calorific value of hydrogen is only about 25% that of natural gas. Consequently, as with cleaned biogas, a greater volume of fuel will have to flow through the burner in order for the same burner power to be attained. While hydrogen burns with a flame with a higher temperature, its luminosity is lower than that of natural gas and so the efficiency with which heat is transferred is compromised. Moreover, hydrogen burns with a very high flame speed, such that burn-back may be a problem for pre-mixed burners unless the speed with which the fuel air mixture emerges from the nozzle is increased. This will place limits on the extent to which hydrogen can displace natural gas unless complete burner replacement occurs.

Syngas – The calorific value of syngas is in the range of about a third to three quarters that of natural gas, depending upon the composition of the waste or biomass being oxygen blown gasified. Consequently, for a significant degree of displacement of natural gas with syngas, burner modifications would be required in order for larger fuel volume throughput to be possible, if the same burner power is to be achieved. While hydrogen makes up a significant proportion of the composition of syngas, the presence of carbon monoxide in the gas mitigates problems of flame luminosity associated with a pure hydrogen fuel.

Pulverised Biomass – As noted in Table 2, where melting of ash is an issue, the use of biomass limits the temperature that can be achieved to about 900°C. This precludes the use of pulverised biomass for kiln firing (where temperatures in excess of 1,100°C are required). In theory, pulverised biomass could be used in burners supplying heat to the drying process, as this requires temperature less than 900°C, but only where this heat is not already sourced from the firing process as waste heat and where the ash created does not damage product aesthetics. According to BCC heat demand for drying is met largely by waste heat at many sites and at some sites it is entirely met by waste heat from the firing process. Ceramic particulate filtration could be used to clean up the combustion products, but his would be expensive. For drying and spray drying applications, biomass combustion in combination with heat exchange to generate clean hot air could displace fossil fuels and is of interest to the ceramics sector, but this would require a new burner design with significant capital requirements which limit the extent to which this could be retrofitted to existing dryers. The British Ceramic Confederation report that the use of biomass for firing of bricks has been attempted in Southern Europe, but only because the required firing temperatures are lower than the firing temperature required for bricks destined for the Northern European market, as the former have less stringent frost resistance requirements than the latter – developing frost resistance requires higher firing temperatures.

5.4.3. Technical Potential for Candidate Fuel Use

BCC have not provided any data on the technical potential for the candidate fuels to be burned in current burners, modified current burners or replacement burners.

Feedback we have received from burner suppliers indicates that modification to existing burners to burn the candidate fuels is not viable and a new combustion system would be required in each case. Therefore, for a burner to burn syngas or hydrogen we have assumed that a new burner system would be required.

Below we present the modelling results for heavy clay firing and drying. In the case of firing, the experience of the sector is that the natural gas currently used to satisfy the overwhelming majority of firing energy cannot be completely substituted by syngas. This is because the lower calorific value of syngas relative to natural gas prevents the very high temperatures required in the ‘peak firing’ zone from being attained. As such, natural gas would have to continue fuelling these firing zines, with syngas being used in the zones requiring lower temperatures. BCC advise that syngas could substitute in the range of 30-80% of natural gas, with 50% being typical. As such, in the modelling carried out, syngas has been assumed to substitute natural gas at the 50% level in the firing process. In the case of drying, where temperature requirements are lower, it is assumed that 100% of natural gas can be substituted by syngas.

Detailed assumptions underpinning modelling of the ceramics sector are presented in Appendix 5 – Ceramics Scenario Assumptions.

5.4.4. Cost Effective Potential for Candidate Fuel Use

The results below present the cost effective potential for the incumbent fuels used for direct heat in the heavy clay sector to be displaced with gaseous candidate fuels. The cost effectiveness of the technical potential for the displacement of incumbent fuel used in the drying process of the heavy clay sector by pulverised biomass is not evaluated, as no information was available on the costs of burners capable of burning pulverised biomass.

Table 29 Ceramics Heavy Clay Firing – Modelling Results for Syngas- Waste, Syngas – Biomass and Hydrogen

	Fuel Consumption (MWh)	Annual CO_{2e} Emissions (tCO_{2e})	30 year CO_{2e} Emissions (tCO_{2e})
Counterfactual	2,187,588	402,735	11,276,579

New Technol./ Candidate Fuel	Gate Fee (£/tonne)	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[76]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m)[77]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[78]
Syngas - Waste	40	1,093,794	-32,814	130,582	3,811,517	135	-31	35.54	15.48
	0	1,093,794	-32,814	130,582	3,811,517	229	219	60.03	28.26
	-40	1,093,794	-32,814	130,582	3,811,517	343	525	89.97	43.88
Syngas - Biomass	N/A	1,093,794	-32,814	185,053	5,336,703	289	381	54.15	35.27

---

[76] Excluding cost of carbon

[77] Excluding cost of carbon

[78] Including cost of carbon

New Technol./ Candidate Fuel	Scenario	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[79]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m) [80]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[81]
Hydrogen	BROWN	1,093,794	0	-104,114	-2,915,197	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	MIXED	1,093,794	0	-104,114	-2,258,411	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	GREEN	1,093,794	0	-275,804	-823,583	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase

---

[79] Excluding cost of carbon

[80] Excluding cost of carbon

[81] Including cost of carbon

	Scenario	CO_{2e} Saving Relative to Counterfactual - 30 Year Appraisal Period (tCO_{2e})	Year in Which New Technology Would Begin to Generate CO_{2e} Savings	Annual CO_{2e} Saving Relative to Counterfactual in 30 years' time (2043) (tCO_{2e})	Year from Which Investment Would Generate CO_{2e} Savings Over 30 year Period Relative to Counterfactual
Hydrogen	BROWN	-2,915,197	Never	-104,114	Never
	MIXED	-2,258,411	Early 2040s	-4,833	~2029
	GREEN	-823,583	2029	142,317	~2017

Table 30 Ceramics Heavy Clay Drying – Modelling Results for Syngas- Waste, Syngas – Biomass and Hydrogen

	Fuel Consumption (MWh)	Annual CO_{2e} Emissions (tCO_{2e})	30 year CO_{2e} Emissions (tCO_{2e})
Counterfactual	395,347	72,783	2,037,935

New Technol./ Candidate Fuel	Gate Fee (£/tonne)	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[82]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m)[83]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[84]
Syngas - Waste	40	395,347	-11,860	47,198	1,377,656	43	-21	31.02	13.28
	0	395,347	-11,860	47,198	1,377,656	76	70	55.51	26.06
	-40	395,347	-11,860	47,198	1,377,656	118	180	85.45	41.68
Syngas - Biomass	N/A	395,347	-11,860	66,886	1,928,930	72	51	37.44	23.22

---

[82] Excluding cost of carbon

[83] Excluding cost of carbon

[84] Including cost of carbon

New Technol./ Candidate Fuel	Scenario	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[85]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m)[86]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[87]
Hydrogen	BROWN	395,347	0	-37,632	-1,053,685	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	MIXED	395,347	0	-37,632	-816,293	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	GREEN	395,347	0	-99,688	-297,680	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase

---

[85] Excluding cost of carbon

[86] Excluding cost of carbon

[87] Including cost of carbon

	Scenario	CO_{2e} Saving Relative to Counterfactual - 30 Year Appraisal Period (tCO_{2e})	Year in Which New Technology Would Begin to Generate CO_{2e} Savings	Annual CO_{2e} Saving Relative to Counterfactual in 30 years' time (2043) (tCO_{2e})	Year from Which Investment Would Generate CO_{2e} Savings Over 30 year Period Relative to Counterfactual
Hydrogen	BROWN	-1,053,685	Never	-37,632	Never
	MIXED	-816,293	Early 2040s	-1,747	~2029
	GREEN	-297,680	2029	51,440	~2017

For all gate fee assumptions (£40/tonne, £0/tonne and -£40/tonne) across both heavy clay firing and drying, using a commercial discount rate of 12%, the new technology of Syngas-waste is more expensive than the counterfactual. The new technology Syngas-biomass is also more expensive than the counterfactual for both heavy clay firing and drying processes.

In the heavy clay firing scenario, detailed data on average burner capacities has been made available by the sector association. This has meant that burners (both natural gas in the counterfactual and new technology and syngas in the new technology case) are modelled as more expensive per MWth than in the modelling for the drying process. This is because the average burner capacity for firing is known and is 80kWth, while the average burner capacity for drying is unknown and is assumed to be a default capacity of 3 MWth, which is also the default for other processes where the average burner capacity is also unknown[88]. The Capex per unit capacity is higher for lower capacity burners than for higher capacity burners (see Appendix 2 – Burner Cost Assumptions), leading to the Capex for all burners being modelled as more expensive in firing than in drying. However, this additional cost of burners seems to have no noticeable effect on the overall economics of the project over the long term relative to the counterfactual, because the implied cost of abatement (£/tCO_{2e}) and implied subsidy (£/MWh of candidate fuel) for firing and drying are similar. This indicates that the economics are heavy determined by the capex of the gasifier and the fuel costs.

For all hydrogen scenarios examined, there is an increase on CO_{2e} emissions relative to the counterfactual over the 30 year assessment period.

In order to put the hydrogen scenarios into context, further information is supplied at the bottom of Table 29 and Table 30 for each of the Brown, Mixed and Green hydrogen scenarios. This additional information shows the first year in which each scenario would generate annual CO_{2e} savings relative to the counterfactual, the annual saving that would be generated at the end of a 30 year assessment period which starts now, i.e. the annual savings in 2043 and the year in which the hydrogen project would have to be invested in if it were to generate net CO_{2e} savings over a 30 year assessment period. For the Brown scenario, CO_{2e} savings are never achieved relative to the counterfactual. Annual savings over the counterfactual would begin in the early 2040s or later for the Mixed scenario and in the late 2029 for the Green scenario. Net CO_{2e} savings over a 30 year assessment period would occur for the Green scenario if investment was made in 2017, while for the Mixed scenario, investment would have to start in 2029.

---

[88] Other process examined in this study for which individual burner capacities are unknown and, therefore, for which individual capacities of 3 MWth are assumed are: Container Glass – Lehr, Container Glass – Forehearth, Heavy Clay – Drying; Maltings – Kilning and Tissue – Drying.

6. Characteristics of Cement Sector

6.1. Cement Sector – Sub-sectors and Direct Heat Consuming Processes

6.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat

For the purposes of this study, the Cement sector is considered to have no sub-sectors, with all participants engaged in the same activity, namely producing Portland cement clinker in rotary cement kilns. Calcium aluminate cement is made in the UK, but data for that process is not included in the figures below. It is understood that this cement is made at one site and the energy consumption is very low compared with the energy consumption associated with all Portland cement manufacture.

The fuel consumed for the generation of all heat and direct heat is given in Table 31.

Table 31 Cement Sector Summary (Data for 2012 supplied by MPA)[89]. Data presented as received.

Sector/Sub-sector	Annual Fuel Consumption for All Heat (MWh)	Annual Fuel Consumption for Direct Heat (MWh)
Cement	6,842,435	6,842,435

All heat consumed in the Cement sector is in the form of direct heat.

6.1.2. Direct Heat Consuming Processes

The main direct heat consuming processes carried out in the Cement sector are calcination of limestone to produce calcium oxide (CaO) (~900°C) and clinker production, whereby CaO is reacted with other components in the raw meal to produce cement clinker (~1400-1500°C). Often, calcination takes place in a separate pre-calciner chamber to which fuel is supplied separately. However, this is not the case at all cement sites. Therefore, the data in Table 32 relate to the overall process of calcination and clinker production.

---

[89] This fuel use for 2012 is for a level of production approximately 30% below the pre-recession level.

Table 32 Direct Heat Consuming Processes (Data for 2012 supplied by MPA)

Direct Heat Consuming Process	**Annual Fuel Consumed for Generation of Direct Heat (MWh)**	**Temperature Requirements of Process (ºC)**	**Characteristics of Heat – Hot Air Composition**
Calcination and Clinker production	6,842,435	Calcination ~900ºC Clinker production ~ 1500ºC	Dirty combustion products tolerated as can be incorporated in final product
Total	**6,842,435**		

At sites that do have separate pre-calciners, fuel for calcination accounts for about 50-70% of total fuel input[90].

6.2. Cement Sector – Characteristics of Direct Heat Consuming Processes

6.2.1. Types of Fuel Used

Table 33 summarises the types of fuel currently used in the combined calcination and clinker production process.

Table 33 Fuels Used in the Calcination and Clinker Production Process in the Cement Sector (Data for 2012 provided by MPA)

Process	**Natural Gas (%)**	**Coal (%)**	**Kerosene (%)**	**Gas Oil (%)**	**Petroleum Coke (%)**	**Grade A Waste Wood Chip (%)**	
Calcination and Clinker production	0.9	52.0	0.3	0.7	5.8	0.4	
Process	**SRF (%)**	**Waste Solvents (%)**	**Tyres (%)**	**Waste Oils (%)**	**Sludges (%)**	**Meat and Bone Meal (MBM) (%)**	**Total (%)**
Calcination and Clinker production	16.5	6.4	11.7	0.1	2.0	3.4	**100**

Currently, solid fuels constitute the large majority of fuel consumption, with coal on its own accounting for more than half of all fuel on an energy basis. The cement sector is a large consumer of waste fuels, some of which are renewable or have a renewable component. The ability of the cement sector to combust a large proportion of waste fuel derives from the alkaline

---

[90] From communications with Mineral Products association (MPA)

environment, very high temperature and long processing times of the clinkering process, whereby harmful species are broken down. Burning a large proportion of waste fuels has been accompanied by significant investments in the industry to comply with the Waste Incineration Directive. The final mineral product also allows the ash from a wide range of combustion products to be absorbed. Overall, about 40% of fuel input is in the form of waste fuels and the sector association estimates that about 18% of fuel input is biomass derived. This figure will be sensitive to the proportion of SRF that is biogenic. The composition of SRF may be deliberately altered through fortification with plastic material in order to raise the calorific value of the fuel. This will tend to depress the proportion of SRF that may be defined as biomass derived. Overall, SRF combusted in the cement sector has a non-biogenic content of about 40%. According to the MPA, the SRF burned in the cement sector has a CO_{2e} factor of about 0.14 $kgCO_{2e}/kWh$.

Currently, an estimated 18% of the fuel input for the generation of direct heat is estimated to be biomass derived.

6.2.2. Fuel Costs

Fuel costs paid by industry vary according to demand. This is demonstrated in DECC's Quarterly Energy Prices document, where, for consumers of fuels, prices are presented according to three sizes of consumer (small, medium and large).

Owing to the preponderance of coal consumption in the cement sector, the size categories and fuel prices pertaining to coal are referred to here.

Overall, in the cement sector 3,558,067MWh of coal was consumed across an estimated twelve sites making clinker. This means that the average coal consumption is about 300,000MWh of coal per annum per site, or about 39,000 tonnes of coal per annum per site, assuming a coal calorific value of 27.7 GJ/tonne[91]. This would place the average site producing clinker in the 'Large' category according to DECC Quarterly Energy Prices, paying £10.48/MWh of coal. The industry is able to substitute easily between coal and pet coke and so, depending upon the relative prices, pet coke could displace coal as the majority fuel. However, over 40% of the direct heat currently comes from fuels that are either not coal or petroleum coke.

6.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions

Table 36 shows the specific energy consumption and specific CO_{2e} emissions for the one identified direct heat consuming process in the Cement sector. The unit of throughput is in terms of tonnes of clinker produced. Note this is not the same as tonnes of cement produced by the sector, as cement is a composite mixture of ground clinker and other additives, such as other cementitious materials and gypsum. The tonnes of cement produced by the sector will exceed the tonnes of clinker produced.

---

[91] Annex 1 Digest of United Kingdom Energy Statistics, 2013

Table 34 Specific Energy Consumption for the Calcination and Clinker Production Process (From data supplied for 2012 by MPA)

Direct Heat Consuming Process	**Specific Energy Consumption (MWh/tonne clinker)**	**Specific CO_{2e} Emissions (tCO_{2e}/tonne clinker)**
Calcination and Clinker production	1.023 (3.683 GJ/tonne clinker)	0.275

6.2.4. Heat Load Factors

Fuel for direct heat load factors is calculated as follows:

$$\frac{\text{Fuel Consumed in Process (MWh)}}{Capacity\ of\ Heat\ Generating\ Technology\ (MW) \times 8760\ hrs}$$

While the fuel consumed in the process is known, the sector is unable to supply information on burner capacities. Consequently, it is not possible to calculate heat load factors. However, from discussions with Mineral Products Association (MPA), clinkering operations would typically run 24 hours a day throughput the year, with a 1-2 week shutdown per year for maintenance (e.g. kiln refractory replacement). This implies heat required for about 95% of the year. This implies a total burner capacity as shown below.

Table 35 Estimated Burner Capacity in Cement[92]

Sub-sector	**Implied Total Burner Capacity (MW)**	**Annual Fuel Consumption (MWh)**	**Assumed Load Factor (%)**
Calcination and Clinker production)	822	6,842,435	95

6.3. Types of Burner Used

Heat for clinkering is supplied by a main burner situated at the outlet end of the cement kiln where the clinker product emerges. These main burners are multi-channel burners allowing for the injection of a variety of fuels into the kiln, as is routine practice at cement sites. There are also normally at least two air channels in the burner through which air is blown to control the shape of the flame developed through the fuel channels. Flame temperatures of about 2000°C are currently relied upon to achieve transfer of heat to the clinker. As noted above, the overwhelming majority of fuel consumed is in solid form and this fuel is pulverised, mixed with air and blown through the fuel channels of the burner.

Where pre-calciners are used, fuel is fed to the pre-calciner either mechanically or pneumatically and the air needed to support combustion comes from the kiln exhaust and from clinker coolers.

---

[92] If the assumed load factor is too high, then this would lead to and underestimate of the total burner capacity, and vice versa.

6.4. Technical Potential for Candidate Fuel Consumption and Barriers

6.4.1. Suitability of Candidate Fuels

Production of cement clinker is a very high temperature process where heat is required to first calcine limestone and then to react the produced CaO with other components of the raw meal to produce cement clinker. This process is tolerant of a wide range of fuel types, including waste fuels, owing to the long residence times, very high temperatures and the ability of the final mineral product to absorb ash from a wide range of fuel types.

6.4.2. Technical Barriers to Candidate Fuel Use

While clinker production is tolerant of a wide range of fuels, the final mix of fuels chosen must satisfy three requirements:

- That the temperature required for the process is generated. This can place some restrictions on the composition of the fuel mix used in the main kiln burners for the clinkering process, where flame temperatures of up to 2000°C need to be generated.
- Emission limit values set for cement sites in terms of NO_2, SOx and dust emissions are not breached.
- Certain quality and consistency of quality of requirements in the final product have to be guaranteed, and this means that the range of fuels that can be consumed is not unrestricted.

In respect of the second point, increasing the use of substitute fuels may require the installation of additional abatement equipment, in addition to additional storage and transportation facilities for the candidate fuels as well as modifications to the existing burners to accept new fuel types.

According to the sector, up to 80% of the fuel requirements for the calcination and clinkering process could be supplied by biomass and still achieve the required temperatures for the clinkering process. However, the origin of this biomass may limit the extent to which it can be used, if this biomass is found in waste fuels and there are limits on the quantities of waste that a particular site is allowed to burn.

6.4.3. Technical Potential for Candidate Fuel Use

Below we consider the technical potential for the candidate fuels to be used in the processes set out above. This technical potential is considered for three scenarios:

- Scenario 1 Current Technical Potential – In this scenario no modifications to the incumbent heat generating technology (i.e. burner) are made. This scenario considers the maximum extent to which each of the candidate fuels may be used in the current burners.
- Scenario 2 Modified Technical Potential – In this scenario the basic incumbent burner is retained but modifications are made to the burner itself, or its supplementary equipment, in order to maximize the quantity of the candidate fuels that can be burned.
- Scenario 3 Replacement Technical Potential – In this scenario the incumbent burner is replaced with another, in order to increase further, beyond the Modified Technical Potential scenario, the quantity of candidate fuel that can be burned.

Table 36 Scenario 1 for Candidate Fuel Consumption in Calcination and Clinkering Process

Technology	Candidate Fuel	
	Biomass (wood waste)	**SRF**
Combined calcination and clinkering burners	40%	40%

Table 37 Scenario 2 for Candidate Fuel Consumption in Calcination and Clinkering Process

Technology	Candidate Fuel	
	Biomass (wood waste)	**SRF**
Combined calcination and clinkering burners	60%	60%

Table 38 Scenario 3 for Candidate Fuel Consumption in Calcination and Clinkering Process

Technology	Candidate Fuel	
	Biomass (wood waste)	**SRF**
Combined calcination and clinkering burners	80%	80%

The replacement technical potential presented in the Tables above would have associated with them the following modifications/replacements:

- Burner modification/replacement to allow for more channels in the multi-channel burner. This would facilitate oxygen enrichment, which in turn would allow the combustion temperature to be raised, thereby allowing greater biomass burning while still achieving the temperature required for clinkering.
- Larger fan to pull the combustion products and other gases through the kiln system. Increasing the proportion of total fuel that is biomass, relative to coal (which is the main incumbent fuel), leads to the generation of more water vapour from the following sources:
    - The water content of the biomass fuel itself
    - From the fact that biomass contains more water generating hydrogen than coal.

In order to maintain the same rate of clinker production, these combustion products will have to be pulled through the kiln system at a faster rate, and this would require a larger fan.

6.4.4. Cost Effective Potential for Candidate Fuel Use

As shown above, there are a wide range of fuel types that can be and are used in clinker production. The reasons for this wide range of possible fuels are discussed in the earlier Section 6.2.1. The candidate fuels being considered in this overall study that are currently used and can be used in greater quantities are Solid Recovered Fuel (SRF) and biomass. The biomass currently used in kilns is varied and ranges from sewage sludge, meat and bone meal to wood waste.

In order to carry out the cost effective analysis, the following simplifying assumptions are made:

- That in extreme cases up to 80% of the energy input to the kiln can come from biomass.
- That SRF will have a biomass content of 60%[93]
- That biomass will be assumed to be Grade A waste wood chip.

Taking into account these simplifications, it is assumed that the technical potential figures presented above of substitution levels of 40%, 60% and 80% relate to Grade A waste wood chip and SRF substitutions, with the balance of fuel consumption being coal. The results of cost effective modelling for these three levels of substitution are presented below. In summary, the scenarios for which cost effective potential will be determined for are:

---

[93] From conversations with companies operating SRF gasifiers

Table 39 Calcination and Clinker Production – 40% SRF / 60% Coal and 40% Biomass / 60% Coal

	Fuel Consumption (MWh)	Annual CO_{2e} Emissions (tCO_{2e})	30 year CO_{2e} Emissions (tCO_{2e})
Counterfactual	6,842,435	1,646,312[94]	46,096,748

New Technol./ Candidate Fuel	Gate Fee (£/tonne)	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[95]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m) [96]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[97]
40% SRF/ 60% Coal	40	2,736,974	0	52,436	1,520,633	-80	-143	-52.61	No subsidy
	0	2,736,974	0	52,436	1,520,633	-265	-648	-174.27	No subsidy
	-40	2,736,974	0	52,436	1,520,633	-203	-479	-133.50	No subsidy
40% Biomass/ 60% Coal	40	2,736,974	0	439,717	12,312,089	566	1602	45.97	26.99
	0	2,736,974	0	439,717	12,312,089	235	715	19.09	8.88
	-40	2,736,974	0	439,717	12,312,089	148	483	12.02	4.12

---

[94] This is lower than the CO2 emissions the MPA say were emitted by the fuel consumed in 2012. MPA say the CO2 emissions were about 1.8 MtCO2. The difference is substantially due to different CO2 factors for coal used by the MPA and used in this study.

[95] Excluding cost of carbon

[96] Excluding cost of carbon

[97] Including cost of carbon

Table 40 Calcination and Clinker Production – 60% SRF / 40% Coal and 60% Biomass / 40% Coal

	Fuel Consumption (MWh)	Annual CO_{2e} Emissions (tCO_{2e})	30 year CO_{2e} Emissions (tCO_{2e})
Counterfactual	6,842,435	1,646,312[98]	46,096,748

New Technol./ Candidate Fuel	Gate Fee (£/tonne)	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[99]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m)[100]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[101]
60% SRF/ 40% Coal	40	4,105,461	0	253,466	7,097,058	-276	-603	-38.89	No subsidy
	0	4,105,461	0	253,466	7,097,058	-386	-896	-54.39	No subsidy
	-40	4,105,461	0	253,466	7,097,058	-251	-534	-35.37	No subsidy
60% Biomass/ 40% Coal	40	4,105,461	0	834,389	23,362,895	690	2,005	29.53	20.12
	0	4,105,461	0	834,389	23,362,895	358	1,118	15.32	8.05
	-40	4,105,461	0	834,389	23,362,895	272	887	11.64	4.88

---

[98] This is lower than the CO2 emissions the MPA say were emitted by the fuel consumed in 2012. MPA say the CO2 emissions were about 1.8 MtCO2. The difference is substantially due to different CO2 factors for coal used by the MPA and used in this study.

[99] Excluding cost of carbon

[100] Excluding cost of carbon

[101] Including cost of carbon

Table 41 Calcination and Clinker Production – 80% SRF / 20% Coal and 80% Biomass / 20% Coal

	Fuel Consumption (MWh)	Annual CO_{2e} Emissions (tCO_{2e})	30 year CO_{2e} Emissions (tCO_{2e})
Counterfactual	6,842,435	1,646,312[102]	46,096,748

New Technol./ Candidate Fuel	Gate Fee (£/tonne)	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[103]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m) [104]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[105]
80% SRF/ 20% Coal	40	5,473,948	0	454,497	12,725,919	-39	-476	-3.06	No subsidy
	0	5,473,948	0	454,497	12,725,919	-74	-571	-5.81	No subsidy
	-40	5,473,948	0	454,497	12,725,919	135	-12	10.61	1.63
80% Biomass/ 20% Coal	40	5,473,948	0	1,229,061	34,413,701	1,248	2,999	36.26	28.59
	0	5,473,948	0	1,229,061	34,413,701	917	2,112	26.65	19.54
	-40	5,473,948	0	1,229,061	34,413,701	830	1,880	24.12	17.16

---

[102] This is lower than the CO2 emissions the MPA say were emitted by the fuel consumed in 2012. MPA say the CO2 emissions were about 1.8 MtCO2. The difference is substantially due to different CO2 factors for coal used by the MPA and used in this study.

[103] Excluding cost of carbon

[104] Excluding cost of carbon

[105] Including cost of carbon

The cost effectiveness of both the SRF and biomass substitution scenarios are sensitive to the assumptions made for the gate fee. This is because SRF is currently used in the sector and is therefore in the counterfactual. Different assumptions about the gate fee will produce different counterfactual costs of DRF consumption and, therefore, different new technology costs relative to it.

From the results presented in Table 39, Table 40 and Table 41 increasing the use of biomass in cement kilns is more expensive than the counterfactual for all combinations of gate fee and level of substitution. The higher the gate fee, the more expensive is the biomass opportunity because a higher gate assumption produces a cheaper counterfactual which results in the new technology seeming more expensive relative to it. The modelling indicates that in order to close the gap between the counterfactual and the use of biomass, a subsidy in the range £4/tonne - £29/tonne would have to be paid. The capital costs for biomass substitution are relatively modest for 40% and 60% substitution levels results for biomass and so the higher cost relative to the counterfactual is driven by the higher cost of biomass relative to coal.

From the results presented in Table 39, Table 40 and Table 41 increasing the use of SRF in cement kilns is less expensive than the counterfactual for all combinations of gate fee assumption and level of substitution, with the exception of the scenario with the least favourable gate fee assumption (-£40/tonne, i.e. the site pays about 0.8 p/kWh of SRF) and highest substitution level (80% SRF/20% coal). Again, with the exception of the highest substitution level (80% SRF/20% coal) the capital costs are relatively modest and this is more than offset by the fuel saving represented by using SRF instead of coal (the main incumbent fuel) – the present cost of SRF is 0.8 p/kWh (gate fee = -£40/tonne) 0 p/kW (gate fee = £0/tonne) and -0.8 p/kWh (gate fee = £40/tonne) while that of coal is 1.1 p/kWh. These findings point to the increased use of waste combustion in the cement sector being a particularly cost effective means of CO_{2e} abatement, indicating that the removal of barriers preventing increased flow of waste to the cement industry would pay dividends at the UK level.

Regarding the use of SRF in cement kilns at increased levels and in the future, MPA has drawn to the attention of the authors a number of issues arising that are likely to have an impact upon costs which are difficult to quantify without further research being undertaken. These issues would erode the current cost effectiveness implied by the above modelling results. These issues are:

Impact of moisture: Waste derived fuels like SRF have a higher moisture content than the main incumbent fuel, coal. At higher levels of substitution this has an impact upon capital costs in that new draught fans are required. While these extra capital costs are included in the modelling (see Appendix 6 – Cement Scenario Assumptions) the effect of higher moisture levels is also to reduce the capacity for clinker production, which will have an associated cost. This is difficult to quantify without further work and so has not been included in the modelling.

Cement quality requirements: One of the ways of reducing the CO_{2e} emissions impact of cement production is to substitute the clinker with other cementitious materials, thereby reducing the amount of clinker that must be produced in the cement kiln for a given level of cement production. In order to maintain the quality standards of the overall cement product (mixture of clinker, clinker substitutes and other additives), the quality of the clicker must be kept very high. As the ash from the solid fuels used in clinker production are incorporated in the clinker product, this implies the need to tighten the specification of the SRF used, which in turn implies more processing and sorting and, therefore, higher costs. These costs have not been included in the modelling.

Additives to control chromium VI: The levels of chromium VI in the final cement product must be controlled, in order to avoid allergic dermatitis in users of the cement. This is achieved by adding reducing agents such as ferrous sulphate and stannous sulphate. SRF can contain high levels of chromium VI and so increased use of SRF will lead to increased reducing agent addition and, therefore, increased costs.

Increased use of kiln gas bypass: High chlorine content of kiln exhaust can lead to blockages of cyclone pre-heaters, through which hot kiln gases pass for preheating raw meal entering the process. This is avoided by bleeding some of the hot kiln gases and cooling it so that the chlorine species are condensed out. This bypass of hot kiln gas will waste a proportion of the heat from the kiln (which would otherwise be used to pre-heat the raw meal). SRF can contain relatively high levels of chlorine and so increased use of SRF could lead to an increase in heat wasted and an increase in the levels of maintenance required for kiln bypass systems, resulting in higher operating costs.

7. Characteristics of Food & Drink Sector

7.1. Food & Drink Sector – Sub-sectors and Direct Heat Consuming Processes

7.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat

The Food & Drink sector can be usefully split into the following sub-sectors:

- Malting
- Industrial Bakeries
- Crisps Snacks Nuts
- Cereal Products
- Instant Coffee
- Biscuits
- Meals
- Oils & Fats
- Other
- Pet Foods
- Canned Food
- Meal Enhancers
- Frozen & Chilled Fruit & Veg
- Meat Fish Poultry
- Chocolate & Sugar
- Misc. (made up of 10 smaller sub sectors).

The relative importance of these sub-sectors in terms of the quantity of fuel consumed for the generation of direct heat is summarised in Table 42.

Table 42 Food & Drink Sector Summary (Data for 2008 supplied by Food and Drink Federation). Data presented as received

Sector/Sub-sector	Annual Fuel Consumption for All Heat (MWh)	Annual Fuel Consumption for Direct Heat (MWh)
Food & Drink	31,261,440 (estimated from ECUK, will include sub-sectors not listed below)	4,789,000
Malting	1,093,000	350,000
Industrial Bakeries	Included in the figure for Food & Drink, above.	1,111,000
Crisps Snacks Nuts		620,000
Cereal Products		462,000
Instant Coffee		466,000
Biscuits		429,000
Meals		215,000
Oils & Fats		260,000
Other		153,000
Pet Foods		164,000
Canned Food		78,000
Meal Enhancers		84,000
Frozen & Chilled Fruit & Veg		49,000
Meat Fish Poultry		63,000
Chocolate & Sugar		80,000
Misc. (10 sub sectors)		205,000

Overall, about 16% of the fuel used to generate heat in the Food & Drink sector is believed to be used for the generation of heat supplied direct to process. Whilst there are other sectors not listed above (for example Spirits and Brewing) the vast majority of heat used in these sectors is supplied indirectly in the form of steam.

7.1.2. Direct Heat Consuming Processes

The main direct heat consuming processes carried out in the Food & Drink sector are given in Table 43.

Table 43 Direct Heat Consuming Processes in Food and Drink Sector (From data supplied by FDF for 2008)

Direct Heat Consuming Process	**Annual Fuel Consumed for Generation of Direct Heat (MWh)**	**Temperature Requirements of Process (ºC)**	**Characteristics of Heat – Hot Air Composition**
Kilns (Malting only)	350,000	250	Low NOx if direct, immaterial if via air-to-air heat exchangers
Drying (all sub-sectors excluding Malting)	609,000	90-250	Must be free of particulate matter and other contaminants not suitable for human consumption or likely to taint smell or taste.
Ovens (all sub-sectors excluding Malting)	2,364,000	100-240	Must be free of particulate matter and other contaminants not suitable for human consumption or likely to taint smell or taste.
Miscellaneous (all sub-sectors excluding Malting)	1,466,000	90-250	Unknown
Total	**4,789,000**		

Overall, about 49% of fuel consumed for the generation of direct heat is for ovens. Other processes consuming direct heat and the nature of the process are listed below:

Kilns – only used in the Malting sector. Currently, natural gas constitutes a very large majority of total fuel consumption for the generation of direct heat (90%). The only other fuel used in quantity is fuel oil (10%).

Ovens – baking of goods, particularly significant in Industrial Bakeries, Biscuits, Cereal Products and Crisps, Snacks & Nuts sub-sectors. The Food & Drink Federation advise that all direct heat can be assumed to come from natural gas, whereas in practice a small amount will come from LPG, gas oil and fuel oil.

Drying – of particular significance in Instant Coffee and Cereal Products to dry out the product. The Food & Drink Federation advise that all direct heat can be assumed to come from natural gas, whereas in practice a small amount will come from LPG, gas oil and fuel oil.

Miscellaneous – additional processes are carried out within the Food & Drink sector involving direct heat. The Food & Drink Federation advise that all direct heat can be assumed to come from natural gas, whereas in practice a small amount will come from LPG, gas oil and fuel oil. These processes include most significantly frying in the Crisps, Snacks, Nuts sub-sector (often via heating of thermal oil as a carrier), roasting in the Instant Coffee sub-sector (where some of the fines are burnt on site for heat generation) and distillation/deodorisation/oil heating pre steam stripping in the Oils & Fats sub-sector). Further detail needs to be obtained on these processes to evaluate the renewable heat potential.

7.2. Food & Drink Sector – Characteristics of Direct Heat Consuming Processes

7.2.1. Types of Fuel Used

This Section sets out the types of fuel consumed for the generation of direct heat in the main direct heat consuming processes.

Table 44 summarises the types of fuel currently used in each process.

Table 44 Fuels Used in the Main Direct Heat Consuming Processes in the Food and Drink Sector (Source: FDF)

Process	**Natural Gas**	**Fuel Oil**
Kilns (Malting only)	90%	10%
Drying (all sub-sectors excluding Malting)	100%	
Ovens (all sub-sectors excluding Malting)	100%	
Miscellaneous (all sub-sectors excluding Malting)	100%	
Total	**99.3%**	

Currently, natural gas constitutes a very large majority of total fuel consumption for the generation of direct heat (over 99%). The remainder comes from burning fuel oil (principally in air-to-air heat exchangers in the Maltings sub-sector).

Currently none of the renewable and low carbon fuels under consideration in this study are consumed with in the Food & Drink sector. However, the specific biomass fuel of ‘coffee fines’ is consumed and requires further quantification.

7.2.2. Fuel Costs

Fuel costs paid by industry vary according to demand. This is demonstrated in DECC’s Quarterly Energy Prices document, where, for consumers of fuels, prices are presented according to three sizes of consumer (small, medium and large).

Owing to the preponderance of natural gas consumption in the Food & Drink sector, the size categories and fuel prices pertaining to natural gas are referred to here.

There are a very large number of sites in the Food & Drink sector (over 1000) but the average fuel for heat consumption is over 27,000 MWh per site (over 40,000 MWh per site for Malting). This would place the average site in the ‘large’ category, paying 2.239 p/kWh (excl. CCL, 2012 prices). In practice though, there will be a large number of small to medium size sites, paying from 2.602 to 3.212 p/kWh. Understanding the distribution of site sizes across the >1,000 sites and, therefore, the distribution of fuel process paid would require further work.

7.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions

The following tables show the specific energy consumption and specific CO_{2e} emissions for each of the main direct heat consuming processes set out in Table 45. The unit of throughput is in terms of tonnes of product emerging from the process.

Table 45 Specific Energy Consumption (Data for Maltings from Maltsters' Association of Great Britain, MAGB)

Direct Heat Consuming Process	**Specific Energy Consumption (MWh/tonne)**	**Specific CO_{2e} Emissions (tCO_{2e}/tonne)**
Kilns (Malting only)	0.700	0.135
Drying (all sub-sectors excluding Malting)	Unknown	Unknown
Ovens (all sub-sectors excluding Malting)	Unknown	Unknown
Miscellaneous (all sub-sectors excluding Malting)	Unknown	Unknown

(Throughput data is currently only available for the Malting sub-sector, so specific energy consumption and specific CO_{2e} emissions have not yet been calculated for all processes).

7.2.4. Heat Load Factors

By Heat Load Factors we here report 'fuel for direct heat load factors', as the information we have received from sectors is based on quantified fuel consumption for the generation of heat rather than quantified consumption of heat. Determining the quantity of heat consumed requires knowledge of:

1) The quantity of fuel consumed, and
2) The quantity and condition of hot air and combustion products leaving the process after heat has been given up to process.

The ratio of 2/1 is the overall efficiency with which energy contained in the fuel is converted into heat and subsequently transferred to the process. This efficiency will vary from process to process and according to the specific requirements of the process.

Fuel for direct heat load factors is calculated as follows:

$$\frac{\text{Fuel Consumed in Process (MWh)}}{Capacity\ of\ Heat\ Generating\ Technology\ (MW) \times 8760\ hrs}$$

This gives an indication of the extent to which the capacity to generate heat is utilised over the course of a year. This requires knowledge of the number and capacity of burners, which is currently unknown for Food & Drink but is known for the Maltings sub-sector. This is shown in Table 46.

Table 46 Estimated burner capacity in Maltings sub-sector (From data supplied by MAGB)[106]

Sub-sector	Approximate Total Burner Capacity (MW)	Fuel Consumption for Kilns(MWh)	Implied Load Factor (%)
Malting	300	350,000	13.3%

The low implied load factor is likely a function of the seasonal nature of Malting, whereby campaigns of Malting occur over a limited portion of the year.

7.3. Types of Burner Used

Additional work required to ascertain.

7.4. Technical Potential for Candidate Fuel Consumption and Barriers

7.4.1. Suitability of Candidate Fuels

The largest areas of direct heat use in Food & Drink are in Ovens and Drying, where the heated air comes into direct contact with the product. For this reason the air needs to be as clean as possible, without contaminants and particulates. In the Malting sub-sector the main use is in Kilns, which are of two types: direct combustion (about 7% of fuel use for kilns), where the hot air conditions must be low in NO_X and gas-to-air heat exchanger, accounting for 93% of kiln fuel use, where the combustion air conditions are immaterial. In the latter case it may be possible for pulverised biomass to displace the incumbent fuel. Gas-to-air heat exchangers could be used in other parts of the Food & Drink sector to overcome concerns relating to the cleanliness of the fuel combustion products, but DECC would have to consider whether this constituted direct heat. This may also present technical issues regarding heat metering, as the quantity of heat delivered to process would be a function of the heat exchanger efficiency.

7.4.2. Technical Barriers to Candidate Fuel Use

The following technical barriers exist in respect of each of the candidate fuels being considered:

Biogas – Raw biogas directly from an anaerobic digester will contain hydrogen sulphide and other acid gases that may have implications for oven components and certainly implications for food. Cleaned biogas would still be dilute from the point of view of methane content and would contain CO_{2e} in the range 30-40%. This means that the calorific value of cleaned biogas is significantly lower than natural gas. Consequently, for the same burner power to be attained, significant burner modifications would be needed to allow a much higher volume throughput of fuel gas. The increased mass flow may also have implications for the way heat is transferred. Cleaned biogas would burn with a lower flame temperature than natural gas. This will place limits on the extent to which cleaned biogas can displace natural gas unless complete burner replacement occurs. (Upgraded biogas – where CO_{2e} is removed – could be substituted one for one with natural gas).

---

[106] If the assumed load factor is too high, then this would lead to and underestimate of the total burner capacity, and vice versa. This would, therefore, lead to an underestimate for the total burner replacement cost in the cost effective modelling

According to the Food and Drink Federation (FDF), the potential for on-site generation of biogas using anaerobic digesters at food and drink sites is limited. In the main, food and drink sites strive to generate as little waste as possible and this would limit the supply of feed material for the AD plant. Opportunities for generation of biogas using AD plant might exist at food processing sites further up the supply chain nearer to the primary agricultural product. At such sites, waste generate may be unavoidable and the supply of feed material to an AD plant may be more reliable.

Hydrogen – The calorific value of hydrogen is only about 25% that of natural gas. Consequently, as with cleaned biogas, a greater volume of fuel will have to flow through the burner in order for the same burner power to be attained.

Syngas – The calorific value of syngas is in the range of about a third to three quarters that of natural gas, depending upon the composition of the waste or biomass being oxygen blown gasified. Consequently, for a significant degree of displacement of natural gas with syngas, burner modifications would be required in order for larger fuel volume throughput to be possible, if the same burner power is to be achieved. While hydrogen makes up a significant proportion of the composition of syngas, the presence of carbon monoxide in the gas mitigates problems of flame luminosity associated with a pure hydrogen fuel.

Pulverised biomass – This may only be a candidate fuel for some of the Maltings sub-sector. Use of this fuel would require complete burner replacement.

7.4.3. Technical Potential for Candidate Fuel Use

In light of the relatively low temperatures required for the kilning process, it is assumed that there is 100% technical potential for the displacement of the incumbent natural gas and fuel oil used in the maltings sector with syngas and hydrogen. This is in contrast with some of the other very high temperature processes considered above (glass melting and ceramics firing) where the calorific values of the candidate fuels are not high enough for a 100% replacement of the incumbent, higher calorific value fuel to be achieved without wider process change, which is not considered in this study. As is the case with the other processes considered above, the use of syngas or hydrogen at these levels is assumed to require complete replacement of the burner system with dedicated syngas or hydrogen burners.

Detailed assumptions underpinning modelling of the maltings process are presented in

Appendix 7 – Maltings Scenario Assumptions.

7.4.4. Cost Effective Potential for Candidate Fuel Use

The results of the cost effective modelling are presented in Table 47.

Table 47 Maltings Kilning – Modelling Results for Syngas- Waste, Syngas – Biomass and Hydrogen

	Fuel Consumption (MWh)	Annual CO_{2e} Emissions (tCO_{2e})	30 year CO_{2e} Emissions (tCO_{2e})
Counterfactual	350,000	67,400	1,887,186

New Technol./ Candidate Fuel	Gate Fee (£/tonne)	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[107]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m)[108]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[109]
Syngas - Waste	40	350,000	0	44,750	1,302,642	804	1,177	617.55	340.68
	0	350,000	0	44,750	1,302,642	834	1,257	640.49	353.46
	-40	350,000	0	44,750	1,302,642	871	1,355	668.52	369.08
Syngas - Biomass	N/A	350,000	0	62,180	1,790,682	854	1,309	476.68	360.47

---

[107] Excluding cost of carbon

[108] Excluding cost of carbon

[109] Including cost of carbon

New Technol./ Candidate Fuel	Scenario	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[110]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m)[111]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[112]
Hydrogen	BROWN	350,000	0	-30,350	-849,819	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	MIXED	350,000	0	-30,350	-639,657	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	GREEN	350,000	0	-30.350	-180,530	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase

---

[110] Excluding cost of carbon

[111] Excluding cost of carbon

[112] Including cost of carbon

	Scenario	CO_{2e} Saving Relative to Counterfactual - 30 Year Appraisal Period (tCO_{2e})	Year in Which New Technology Would Begin to Generate CO_{2e} Savings	Annual CO_{2e} Saving Relative to Counterfactual in 30 years' time (2043) (tCO_{2e})	Year from Which Investment Would Generate CO_{2e} Savings Over 30 year Period Relative to Counterfactual
Hydrogen	BROWN	-849,819	Never	-30,351	Never
	MIXED	-639,657	2043	1,418	~2028
	GREEN	-180,530	2028	48,504	~2016

From the results presented in Table 47 the cost of Syngas-waste and Syngas-biomass are both more expensive than the counterfactual. This was seen with the overwhelming majority of other processes for which the cost effective potential for Syngas was evaluated. However, the costs of syngas from both sources is about an order of magnitude more expensive per unit of syngas delivered to the process than for the other processes examined in this study. The main reason for this difference is the low load factors in the Maltings kilning process relative to the other processes considered. Kilning requires gasification capacity to meet demand for syngas that is concentrated in part of the year. This means that the capital costs incurred are spread over a much smaller amount of syngas than is the case for the other processes examined, leading to much higher relative costs.

For all hydrogen scenarios examined, there is an increase on CO_{2e} emissions relative to the counterfactual over the 30 year assessment period.

In order to put the hydrogen scenarios into context, further information is supplied at the bottom of Table 47 for each of the Brown, Mixed and Green hydrogen scenarios. This additional information shows the first year in which each scenario would generate annual CO_{2e} savings relative to the counterfactual, the annual saving that would be generated at the end of a 30 year assessment period which starts now, i.e. the annual savings in 2043 and the year in which the hydrogen project would have to be invested in if it were to generate net CO_{2e} savings over a 30 year assessment period. For the Brown scenario, CO_{2e} savings are never achieved relative to the counterfactual. Annual savings over the counterfactual would begin in the 2043 for the Mixed scenario and in 2028 for the Green scenario. Net CO_{2e} savings over a 30 year assessment period would occur for the Green scenario if investment was made in 2016, while for the Mixed scenario, investment would have to start in 2028.

8. Characteristics of Oil Refining Sector

With the exception of some data on fuel consumption and some anecdotal information, this section is constructed entirely from literature sources and internal knowledge.

8.1. Oil Refining Sector – Sub-sectors and Direct Heat Consuming Processes

8.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat

The UK Oil Refining sector is relatively compact, with seven currently operating sites. These seven coastal sites supply approximately 90% of the UK market demand for petroleum products. In addition, the UK operates a significant total refining capacity (third largest in the EU[113])..

More than half of the product is supplied to market by pipeline to major oil terminals and another third by sea tanker.

Hard figures for total fuel consumption for the sector are not published, and nor are figures for the fuel that is consumed for direct applications within the sector. The sector indicated that it would not be able to assist with this study in the timescales required. The sector also indicated that it saw little technical potential for a migration away from its current fuel mix to a fuel mix lower in carbon. This is explained in more detail below.

Anecdotal evidence obtained through conversations with industry representatives suggests that between 50% and 70% of the total fuel consumed by oil refineries is used for the generation of heat supplied direct to process. The remainder of the fuel consumed is used for the generation of steam for other heating purposes.

Six of the seven operating refineries in the UK currently operate Combined Heat and Power (CHP) installations that supply the steam requirements for the sites. In addition, all sites operate various forms of waste heat recovery to generate steam for use at the installation. A particular example of this is where sites operate a ‘partial burn’ catalytic cracker. Here a syngas is created by the regeneration of the catalyst (combustion of the petroleum coke that forms on the surface of the catalyst) that is rich in carbon monoxide (CO). This syngas is combusted in a CO Boiler to recover significant quantities of steam.

United Kingdom Petroleum Industrial Association (UKPIA) has supplied data on the fuels consumed by UK refineries in 2012[114]. These fuels are consumed for three purposes:

- Generation of direct heat

---

[113] UK PIA Statistical Review 2013

[114] The refineries considered in the analysis are as follows: Stanlow – Essar Energy PLC; Fawley – ExxonMobil Co. Ltd; Grangemouth – Ineos Refining Ltd; Lindsey Oil Refinery – Total (UK); Pembroke – Valero Energy Ltd.; Killingholme – Phillips 66 UK, Milford Haven – Murco Pet. Ltd, Coryton – Petroplus; Dundee- Nynas UK AB and Eastham- Eastham Refinery Ltd. Note that Coryton is no longer operating.

- Generation of steam
- During flaring of by-product gases.

Table 48 shows the fuels consumed at refineries for these purposes in 2012.

Table 48 Fuel Consumption at Seven Main UK Refineries (2012 for 2012 provided by UKPIA). Data presented as received

	Refinery Gas[115] (GWh)	Fuel Oil/Gas Oil (GWh)	Petroleum Coke[116] (GWh)	Natural Gas (GWh)	Total (GWh)
Fuel Consumed	28,970	4,088	15,164	10,929	59,151
	49.0	6.9	25.6	18.5	100.0

Seven of these refineries had CHP serving them in 2012 and the fuel in Table 48 will include fuel to CHP where the CHP is ‘embedded’ in the refinery. The fuel to the embedded CHP for 2012 was identified from CHPQA data and removed from the data supplied by UKPIA. This removes fuel for power and steam generation. If the assumption is made that all steam is generated by CHP, what remains after removing the embedded CHP fuel from the total refinery fuel is the fuel for direct heat at the refineries, plus fuel for direct heat and steam at the refineries without CHP. The refineries without CHP are: Coryton, Dundee and Eastham. Unfortunately, it has not been possible to estimate the fuel for steam and direct heat at these other refineries. Therefore, the figures presented in Table 49 will be an overestimate of the fuel for direct heat, but are nevertheless considered a reasonable indication of the level of fuel consumption for direct heat and the types of fuel consumed for this heat generation.

---

[115] A by-product of the refining process

[116] A by-product of the refining and cracking process

Table 49 Fuel Consumption for the Generation of Direct Heat at Refineries (Derived using data provided by UKPIA and CHPQA data)

Fuel Consumed	Refinery Gas (MWh)	Fuel Oil/ Gas Oil (MWh)	Petroleum Coke (MWh)	Natural Gas (MWh)	Total (MWh)
	25,053	520	15,164	0	40,737
	61.5%	1.3	37.2	0.0%	100.0%

The fuel consumed for all heat generation, some power and a small amount of flaring is 59,151 GWh, while the estimated fuel for direct heat generation is 40,737 GWh, which is about 69% of all fuel consumed at the refineries included in the analysis. Therefore, based on the above methodology and assumptions, we estimate that a large majority of the fuel for heat generation is fuel consumed for the generation of direct heat. However, over 98% of the fuel for direct heat is fuel which is generated as a by-product of the refining process (refinery gas and petroleum coke). Arguably, if these fuels were not consumed for the generation of direct heat they would either be flared (i.e. burned without the recovery of heat) or, assuming their market value warrants it, transported to another place where they would be burned.

8.1.2. Direct Heat Consuming Processes

The direct heat consuming process utilised on refinery sites is the fired heater (also known as a process heater or process furnace). The fired heater is the mainstay of refinery processes – each refinery step is reliant on the operation of its fired heater. The process fluid requiring heating is passed through a heater ‘box’ in tubes, through radiant and convection sections. A bank of burners provides a carefully balanced heat profile across the heater – flame luminosity and length are particularly important for maintaining consistent heating of the process fluid in the heater. Burners are typically (and increasingly so) gas-fired, although some heaters continue to fire liquid fuels. Fired heater designs vary, depending on manufacturer, purpose and required duty.

The number and capacity of fired heaters in operation on UK Refineries varies, depending on the specific details of each refinery, and the age and particular design of each processing train. Typically, a refinery may have as many as twenty to thirty fired heaters, ranging in individual capacity from 10MWth to 150MWth.

8.2. Oil Refining Sector – Characteristics of Direct Heat Consuming Processes

8.2.1. Types of Fuel Used

The UK Oil Refining sector currently uses a relatively narrow range of fuels for heat generation. This is driven primarily by the need to reduce the use of semi-processed products that otherwise could be used as refinery feedstock to produce the premium petroleum products for sale. Also of importance is the availability of by-product gases which are suitable for combustion on site but which would require considerable further processing before they can be used as feedstock or sold on.

Figure 3Simple Fired Heater Schematic (obtained from www.area4info.com) (Visited: 24/10/14)

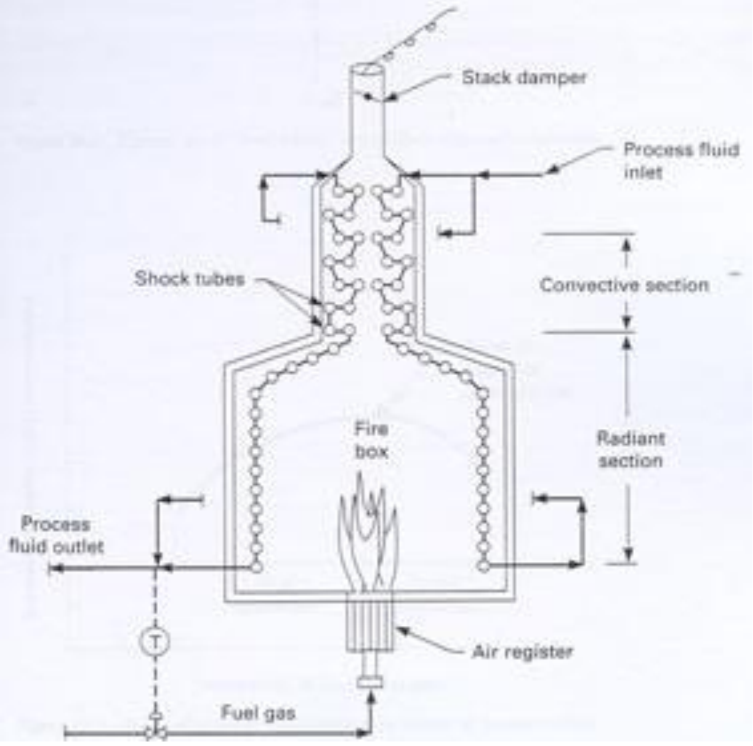


Table 48 and Table 49 show the types of fuel used for all purposes and for the generation of direct heat, respectively. From Table 49it is estimated that over 98% of the fuel for the generation of direct heat is derived from by-product fuels (refinery gas and petroleum coke).

Currently none of the renewable and low carbon fuels under consideration in this study are consumed within the Oil Refining sector, unless refinery fuel gas is considered as a low carbon fuel[117].

8.2.2. Fuel Costs

---

[117] Refinery gas could be considered a low carbon fuel for the generation of useful heat if the alternative use of it is flaring.

Fuel costs paid by industry vary according to demand. This is demonstrated in DECC's Quarterly Energy Prices document, where, for consumers of fuels, prices are presented according to three sizes of consumer (small, medium and large). The refinery sector will fall into the 'large' category, paying 2.403 p/kWh (excl. CCL) for its natural gas consumption. Prices of Refinery Gas are not relevant here as these are by-products of the petroleum refining activity and are not traded. As such, there is no market price to refer to.

8.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions

Additional work required to ascertain.

8.2.4. Heat Load Factors

The sector was unable to supply these data. However, the load factors for the generation of direct heat at refineries are likely to be very high. Assuming that the refinery operates throughout the year (8760 hrs) the heat generating capacity would be:

40,737 GWh/8,760 hrs = 4.650 GW[118]

8.3. Types of Burner Used

Additional work required to ascertain.

8.4. Technical Potential for Candidate Fuel Consumption and Barriers

8.4.1. Suitability of Candidate Fuels and Technical Barriers

Process heating is supplied by burners producing design length flames in the fired heater radiant section. These flames have to cover either the length or width of the section in order for heat to be efficiently transferred to the process fluid in the flow tubes. Heat is transferred to the tubes via radiant heating in the radiant section, and convection heating in the convection section of the heater.

While solid, candidate fuels in pulverised form could in theory be blown through burners, there are three key reasons that make this impractical. The first is the need for a fuel delivery system that can get a potentially bulky fuel to a number of disparate areas on a large site. The second and third relate to the impact of higher entrained dust in the exhaust gases, causing deposition on the heater tubes (and unacceptable reduced heat transfer and lifecycle impacts), together with increasing emissions from the heater stack with unacceptable regulatory impacts.

Application of candidate liquid or gaseous fuels to fired heaters, while in theory technically possible, would be hampered by the technical difficulties of supplying a substitute fuel to the number of fired heaters located on refinery sites. This would incur significant issues in connecting the heater burners to individual supplies. The main potential operational disadvantage in using alternatives in fired heaters is the potential thermal instability across the

---

[118] If the assumed load factor is too high, then this would lead to and underestimate of the heat generating capacity, and vice versa.

heater, due to changes to the burner performance parameters (flame length, temperature, consistency and luminosity). All of this suggests significant operational risks in attempting process modification or change and a considerable barrier to its adoption.

For these reasons only the potential to burn candidate fuels that may completely substitute the current fuel are likely to be considered by the sector. This would mean fuels such as biomethane or biodiesel. These fuels could be incorporated into a utility supply system that already exists on a refinery without too great an impact (for example injection of biomethane into the existing site natural gas grid). However, concern has been expressed at the exposure of an operator to fuels that are of much wider market interest and potential fuel cost increases that are outside of the control of the refinery operator.

Anecdotal evidence from fired heater manufacturers suggests that no research has been undertaken into the potential for technical modifications to fire renewable or low carbon fuels. In particular, no market interest has been expressed to the manufacturers.

8.4.2. Technical Potential for Candidate Fuel Use

Discussion with refinery operators and industry representation has resulted in the robust message that the oil refining sector is extremely unlikely to consider any changes of the nature being reviewed in this report, or adoption of renewable or low carbon fuels for direct heat generation[119].

It was also stated that the single most important consideration of a fired heater is to provide heat, with a 98% plus availability, and there is absolutely no room for failure or operational downtime – the core process cannot be limited by the utility. For this prime reason the sector is extremely risk averse with respect to process changes.

In any case, as set out in 8.2.1 it is estimated that over 95% of the fuel currently used for the generation of direct heat are by-products of the refining process (refinery gas and petroleum coke). If not used to generate heat these fuels would either be combusted without recovery of the heat (flaring) or, assuming that the market value of the fuel warrants it, transported to another place for combustion. As such, it can be argued that there is very little potential for the substitution of incumbent fuels at refineries with renewable or lower carbon alternatives that does not displace the CO_{2e} emissions associated with incumbent fuel use to another application or place.

8.4.3. Cost Effective Potential for Candidate Fuel Use

Lack of granular and confirmed data from the sector makes this problematic. However, estimates of the quantity and type of fuel consumed for the generation of direct heat suggest that there is little technical potential to displace incumbent fuel consumption and not simply displaced the CO_{2e} emissions associated with incumbent fuel use to another application or place.

---

[119] In addition to technical barriers, a key message has been the lack of access to any capital in the industry to affect process change, other than essential operating changes and modifications that are made during the regular refinery turnaround periods (scheduled maintenance, lasting 4 to 6 weeks, approximately every 4 years). An example was given of the choice between uprating tube materials in convection banks (bringing improved efficiency and tube life) versus changing to (relatively) expensive liquid fuels, where the risks of a short term policy and operational difficulties outweigh any potential benefits

8.5. Comparison with DUKES Data

Table 1.1 (Energy Industry Use section) of DUKES 2013 shows fuel consumption by refineries of 5,265 ktoe (61.2 TWh). This compares with the fuel consumed figure in this study of 59.2 TWh.

9. Characteristics of Chemicals Sector

9.1. Chemicals Sector – Sub-sectors and Direct Heat Consuming Processes

9.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat

The Chemicals sector is very diverse. It can be split in to two broad sub-sectors, which can then be described by a number of further sub-sectors.

Table 50 Chemicals Sector (Source: CIA)

Broad Sub-Sector	Sub-Sector
Organic Chemicals	Manufacture of other organic basic chemicals
	Manufacture of plastics in primary forms
	Manufacture of synthetic rubber primary forms
	Manufacture of pesticides & agro-chemicals
	Manufacture of basic pharmaceutical products
	Manufacture of man-made fibres
Inorganic Chemicals	Manufacture of dyes and pigments
	Manufacture other inorganic basic chemicals
	Manufacture of fertilisers, nitrogen compounds

The IPPC Bureau classifies activities as

- Chlor- alkali manufacturing industry
- Large volume Inorganic chemicals industry – Solids and others
- Large volume Inorganic chemicals industry – Ammonia, acids and fertilisers
- Large volume Organic chemicals
- Manufacture of Organic fine chemicals

These activities are the sector headings for the BAT[120] Reference Notes. The character of energy use can also be broadly sorted according to these categories:

---

[120] BAT = Best Available Techniques

- **Chlor- alkali manufacturing industry**. This is dominated by electrochemistry. Hydrogen by-product is burned on site for hot water and steam for caustic soda concentration.
- **Large volume Inorganic chemicals industry – Solids and others**. A diverse range of industries with some high temperature process heat use for ore and other raw material treatment in kilns, some calciners, dryers and directly fired heaters. Other processes involve the liquid phase digestion of ores etc. which utilises process steam.
- **Large volume Inorganic chemicals industry – Ammonia, acids and fertilisers**. This is a major sector supplying bulk chemicals for fertiliser and further synthesis. It covers ammonia, urea and ammonium based fertilisers, nitric acid, phosphoric acid and phosphate fertilisers. There is substantial use of fired heaters for ammonia production but waste heat is used internally within the process for mechanical drives and process steam.
- **Large volume Organic chemicals**. A diverse sector. A sample selected in the BREF suggests that the majority of installations require heat in the form of process steam with few processes using high temperature operations. This also includes the petrochemicals group which has a substantial use of directly fired process heaters.
- **Manufacture of organic fine chemicals.** This covers the preparation of dyes, pigments, biocides, explosives and pharmaceuticals. Production is often in small scale batch processes at modest temperatures. The heat demand is almost exclusively process steam or hot water.

This summary indicates the sub sectors of greatest interest for this study are in the large volume inorganic sectors and the large volume organic sector. From conversations with industry sources, petrochemicals almost certainly accounts for the greatest use of fuel for the generation of direct heat in the form of fired process heaters and furnaces. This is thought to apply particularly to high tonnage primary precursors such as olefins and aromatics that are manufactured or separated from petroleum fractions. It is suggested that up to 70% of the energy input to primary petrochemicals is to fired process heaters and reaction furnaces supplying this direct heat.

Another significant consumer of direct heat is steam reforming of natural gas for the generation of synthesis gas, which is subsequently used for producing hydrogen, ammonia (for agrochemicals and nitric acid) and methanol, which is important as a chemical precursor. These reactions require high temperatures and short residence times in the reactor require high rates of heat transfer that can only be supplied by direct heat. It is suggested that over 70% of the fuel input to steam reforming is supplied to the reformer furnace providing the direct heat.

The Chemicals Industry Association (CIA) has provided estimated fuel consumed for the generation of all types of heat consumed by the sector in 2006, as this is the latest year for which data are available. Data for the overall Chemical sector has been provided for two sub-sectors, which together cover the whole sector. These sub-sectors are known as: Broad Organic and Broad Inorganic.

Data was provided covering both fuel consumed for the generation of heat and quantity of imported heat in the form of steam. As we are interested in the fuel consumed for the generation of direct heat, we have disregarded the energy figure for imported steam and then undertaken a refining exercise in respect of the remaining fuel to estimate the fuel consumed for the generation of direct heat. This refining exercise is based on the following assumptions:

- That all of the sector’s demand for steam remaining after the heat imports figure is disregarded is met by CHP. In practice, there will be some steam generated just in boilers and so this assumption will tend to understate the fuel for indirect heat in the sector.
- The only heat generated by CHP in the Chemicals sector is in the form of steam or hot water (i.e. indirect heat). In practice, some of the heat from CHP will be in the form of direct heat and so this assumption will tend to overestimate the fuel for indirect heat in the sector.

CHP statistics from DUKES and CHPQA for 2006 have been consulted in order to estimate the fuel consumed by CHP. A Chemicals site with CHP will have the CHP fuel for heat and power generation included in the data provided by CIA. This fuel needs to be removed from the CIA provided figures in order to leave the fuel for direct heat.

As stated above, the imported heat included in the CIA data has already been disregarded. This suggests that fuel for CHP heat consumed by 3rd parties supplying Chemicals sites can be disregarded. This means that it is necessary to identify the CHP schemes embedded at Chemical sites, and remove this fuel from the CIA data.

The CHPQA database of schemes operating in 2006 was consulted and those schemes categorised as serving the Chemicals sector were identified. 3rd party CHP schemes, i.e. those not embedded at Chemicals sites but exporting heat to them were identified and removed from the analysis, as it is considered that this heat had already been removed from the CIA data (see above). For the remaining CHP schemes, the fuel consumed for the generation of heat and power was determined. This fuel was then removed from the CIA provided data, resulting in an estimate of the fuel for direct heat. This is summarised in Table 51 below:

Table 51 Sub Sector Fuel Consumption (2006 Data from CIA). Data presented as received

Sector/Sub-sector	Annual Fuel Consumption for All Heat (MWh)	Estimated Annual Fuel Consumption for Direct Heat (MWh)
Organic Chemicals	47,336,908	32,331,909
Inorganic Chemicals	13,045,962	8,910,913
Total	**60,382,871**	**41,242,522**

9.1.2. Direct Heat Consuming Processes

The main direct heat consuming processes carried out across the Chemicals sector are given in Table 52. These estimations of the heat consumed across the sub-sectors are based on benchmarks and production rate information given in the BAT Reference Documents and other documents generally available.

Organic Chemicals

It is estimated that around one third of the heat used in the organic chemicals subsector is used as direct heat in Olefin production. This is represented by just four facilities in the UK with steam cracker units at Mosmorran, Wilton, Grangemouth and Fawley. The direct heat used in these specific processes is for fired heaters providing heat into the feedstock prior to its introduction to the steam cracker unit. Some of these sites are integrated with adjacent refineries. As a result of this, refinery gas is made available for cracker process heaters which would limit the extent to which the candidate fuels could displace the incumbent fuel, as the incumbent fuel (refiner gas) would either be burned in another application at the chemical site or refinery or flared.

Inorganic Chemicals

The single largest consumer of direct heat in the inorganic chemicals subsector is in the production of Ammonia via steam reforming. It is estimated that this accounts for nearly 20% of the total direct heat consumption in the inorganics sector. The direct heat here is used in a fired heater type process furnace.

Other consumers of note in the inorganic sector are in the manufacturing of titanium dioxide, lead oxide and magnesium compounds. This accounts for almost 10% of the total direct heat consumption. This heat is used in calcining and drying processes, although data is not available to identify the consumptions of these individual sub-processes.

Estimations also suggest that Soda Ash production could account for a further 700,000MWh of heat use, in the form of coal in the lime kiln part of the process. However, the data provided from the sector does not include any coal use in the inorganic subsector so this is not clear. Coal is used in the process as the kiln gases are CO_{2e} rich, which is essential for later steps in the manufacturing process where the kiln gases are used.

Table 52 Example Direct Heat Consuming Processes

Direct Heat Consuming Process	Annual Fuel Consumed for Generation of Direct Heat	Characteristics of Heat – Flame Temperature Requirement (ºC)	Characteristics of Heat – Hot Air Composition
Process heating (via fired heaters) (Organic & Inorganic sectors) Ammonia furnaces	Principal Consumers: Organic sector– Ethylene >14TWh Inorganic Sector – Steam reforming – >1.5TWh	Varies depending on the specific product process, but generally high	Must be free of particulate matter
Calciners/Reactors (Inorganic sector)	>1.3TWh	Varies depending on the specific product process, but generally high (for example, magnesium oxide calcination requires 1800°C)	Many processes require a solid fuel such as coal or coke. Solvay process for Soda Ash requires CO_{2e} rich kiln gas for use in other parts of process.
Drying	Inorganic Sector - 161,262MWh	800 - 1300	Must be free of particulate matter. Some processes will require clean gas to prevent contamination of product.

Refer to Section 8.1.2 for more detail regarding the operation of fired heaters for process heating. All the same principles of operation apply to the chemical sector as with the oil refining sector. The petrochemical sub-sector in particular has a closely linked heritage with the refinery sector and sites are often co-located.

Drying is a much smaller individual process, and technically offers greater potential for substitution with candidate fuels into burners. A range of burner types and sizes may be applied. The principal fuel adopted is natural gas, and thus gaseous candidate fuels will be of principal interest. Depending on the nature of the product being dried, there may be opportunities to consider alternative phase fuels such as liquids, or even solids fired as a dust, provided appropriate fuel preparation and handling equipment was available and suitable for installation and operation on a complex site.

9.2. Chemicals Sector – Characteristics of Direct Heat Consuming Processes

9.2.1. Types of Fuel Used

This section sets out the types of fuel currently consumed in the generation of direct heat in the sector. Table 53 summarises the proportions of fuel currently used in each of the broad sub-sectors. This does however include the fuel used to generate steam (and power where CHP is adopted).

Table 53 Fuel Consumption Across Broad Sub-Sectors (Source: CIA)

Broad Sub-sector	Natural Gas	Gas/Fuel Oil	Manufactured Fuel	Coal
Broad Organics	41%	3.4%	54%	1.3%
Broad Inorganics	96%	3.7%	0	0

Manufactured Fuel above relates to by-product/waste gases generated on or adjacent which are subsequently combusted to provide heat for chemical processes. Examples include refinery gas and hydrogen.

We believe that, with the exception of hydrogen, none of the candidate fuels under consideration in this study are used for the generation of heat. Where hydrogen is used, it is believed to be a by-product of chemical processes, originating either form a fossil fuel, as would occur at a petrochemical site or as a by-product of electricity consumption during electrolysis. In both these cases the original source of energy is non-renewable and so the hydrogen by-product would have a finite carbon factor associated with it.

9.2.2. Fuel Costs

Fuel costs paid by industry vary according to demand. This is demonstrated in DECC’s Quarterly Energy Prices document, where, for consumers of fuels, prices are presented according to three sizes of consumer (small, medium and large). The Chemicals sector is so diverse that there will be sites that fall into all three of these classifications. For confidentiality reasons, the sector association was not able to share fuel consumption data that would illustrate this range.

9.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions

More work required to ascertain.

9.2.4. Heat Load Factors

More work required to ascertain.

9.3. Types of Burner Used

More work required to ascertain.

9.4. Technical Potential for Candidate Fuel Consumption and Barriers

Many of the same barriers that are considered for the oil refining sector are applicable to the chemicals sector. Many of the chemicals manufacturing sites which are using the technologies utilising direct generation of heat are of a similar, complex, nature to refinery sites (and often have spun out of larger operations as the sectors have developed).

9.4.1. Suitability of Candidate Fuels

Refer to the discussion on suitability and barriers given in Section 8.4.1. As described above, most of these barriers will also apply to the large volume chemicals sector.

However, there may well be greater potential to burn gaseous candidate fuels in this sector. The candidate fuels under consideration are, therefore, biogas, hydrogen and syngas.

9.4.2. Technical Barriers to Candidate Fuel Use

The following technical barriers exist in respect of each of the candidate fuels being considered:

Biogas – Raw biogas directly from an anaerobic digester will contain hydrogen sulphide and other acid gases that may have implications for dryer components. As such biogas would have to be cleaned-up before it could be combusted. Cleaned biogas would still be dilute from the point of view of methane content and would contain CO_{2e} in the range 30-40%. This means that the calorific value of cleaned biogas is significantly lower than natural gas. Consequently, for the same burner power to be attained, significant burner modifications would be needed to allow a much higher volume throughput of fuel gas. The increased mass flow through a furnace may also have implications for the way heat is transferred to the product. Cleaned biogas would burn with a lower flame temperature than natural gas. These will place limits on the extent to which cleaned biogas can displace natural gas unless complete burner replacement occurs. (Upgraded biogas or biomethane – where CO_{2e} is removed – could be substituted one for one with natural gas).

Hydrogen – The calorific value of hydrogen is only about 25% that of natural gas. Consequently, as with cleaned biogas, a greater volume of fuel will have to flow through the burner in order for the same burner power to be attained. While hydrogen burns with a flame with a higher temperature, its luminosity is lower than that of natural gas and so the efficiency with which heat is transferred to the product will be compromised. Moreover, hydrogen burns with a very high flame speed, such that burn-back may be a problem for pre-mixed burners unless the speed with which the fuel air mixture emerges from the nozzle is increased. This will place limits on the extent to which hydrogen can displace natural gas unless complete burner replacement occurs.

Syngas – The calorific value of syngas is in the range of about a third to three quarters that of natural gas, depending upon the composition of the waste or biomass being oxygen blown gasified. Consequently, for a significant degree of displacement of natural gas with syngas, burner modifications would be required in order for larger fuel volume throughput to be possible, if the same burner power is to be achieved. While hydrogen makes up a significant proportion of the composition of syngas, the presence of carbon monoxide in the gas mitigates problems of flame luminosity associated with a pure hydrogen fuel.

9.4.3. Technical Potential for Candidate Fuel Use

Further information is required from the sector to enable more to be said about this.

The sector association does not have this data available, and it would be necessary to obtain the information from its members. Given the size and diversity of the sector, this would take much longer that the timescales in this study allow. Targeting key direct heat consuming processes in the sector, once identified in the sections above, may be a sensible, pragmatic approach to addressing the diversity on scope challenges.

9.4.4. Cost Effective Potential for Candidate Fuel Use

More work required to ascertain.

9.5. Comparison with Dukes Data

CIA provided data indicating that in 2006 the sector consumed 67.9 TWh of fuel and imported heat. Removing imported heat, as it is assumed to be steam (indirect heat), leaves 60.4 TWh. Removing fuel for associated CHP (thus removing fuel for power and fuel for steam) leaves 41.2 TWh. This is a crude estimate of direct heat. It will be an overestimate as there will be some steam generation at sites without CHP and the fuel for this steam will be in the 41.2 TWh figure. Table 1.1 of Dukes shows final energy consumption of Chemicals in 2006 (not including electricity but including heat sold) was 68.0 TWh and so is close to the 67.9 TWh figure provided by CIA.

10. Characteristics of Paper & Pulp Sector

10.1. Paper & Pulp Sector – Sub-sectors and Direct Heat Consuming Processes

10.1.1. Sub-sectors, Fuel for Heat and Fuel for Direct Heat

The Paper and Pulp sector is comprised of the following sub-sectors:

- Tissue
- Newsprint & Graphics
- Packaging
- Speciality

The relative importance of these sub-sectors in terms of the quantity of fuel consumed for the generation of direct heat is summarized in Table 54.

Table 54 Paper & Pulp Sector Summary (2012 Data from Confederation of Paper Industries, CPI). Data presented as received

Sector/Sub-sector	Annual Fuel Consumption for All Heat (MWh)	Annual Fuel Consumption for Direct Heat (MWh)
Paper	9,900,000	1,338,000
Tissue		1,011,000
Newsprint & Graphics		37,000
Packaging		34,000
Speciality		250,000

Overall, about 13.5% of the fuel used to generate heat in the Paper & Pulp sector is used for the generation of heat supplied direct to process.

Across all sub-sectors direct heat is **only** consumed in the drying process. Most heat required for drying in the sector is actually supplied indirectly in the form of steam in cylinder dryers and Yankee dryers, and so does not appear in the figures given in Table 54.

10.1.2. Direct Heat Consuming Processes

Direct heat for drying is used in the follow situations:

Through Air Dryers – Used in the manufacture of tissue

Dryer Hoods (with IR or air impingement) – These may be over Yankee dryers in the tissue sector or over cylinder dryers in other sub-sectors. Within dryer hoods there may be either infra-red heaters (IR) or air impingement heaters, both of which use natural gas burners.

Coater Dryer – These are gas fired IR heaters used to dry coatings applied to paper already dried by cylinder dryers. The coating cannot be dried by a cylinder dryer without damaging the coating and so must be dried indirectly.

Pulp Driers – These are used to dry pulp like paper products, e.g. egg boxes rather than the pulp that is the material input to the paper making process. Gas is fired in ovens and the product placed inside the ovens to be dried.

The quantities of fuel used in the above mentioned types of dryer are given in Table 55

Table 55 Direct Heat Consuming Processes (2012 Data from CPI)

Dryer Type	**Annual Fuel Consumption for Direct Heat (MWh)**
Through Air Dryer (TAD)	360,000
Dryer Hoods (with IR or air impingement)	815,500
Coater Dryer	73,500
Pulp Dryers	89,000
Total	**1,338,000**

10.2. Paper & Pulp Sector – Characteristics of Direct Heat Consuming Processes

10.2.1. Types of Fuel Used

The Paper and Pulp sector consumes either natural gas or biomass for both the generation of heat and electricity. Table 56 shows how these fuels are consumed.

Table 56 Fuels Used (2012 Data from CPI)

Category of Consumption	**Annual Fuel (MWh)**
Total Fuel Consumption	14,500,000 (NG + biomass)
of which natural gas	12,300,000
of which natural biomass	2,200,000
Total Fuel for Heat	9,900,000 (NG + biomass)
Total Fuel for Electricity	4,600,000 (NG + biomass)
Total Fuel for Direct Heat	1,338,000 (All NG)

Biomass is only used for the generation of steam which is either used to generate electricity on site or is supplied as steam to process.

Heat consumed is either in the form of steam or as direct heat. All direct heat consumed is from the combustion of natural gas.

Currently none of the renewable and low carbon fuels under consideration in this study are consumed with in the Paper sector for the generation of direct heat[121].

10.2.2. Fuel Costs

Fuel costs paid by industry vary according to demand. This is demonstrated in DECC's Quarterly Energy Prices document, where, for consumers of fuels, prices are presented according to three sizes of consumer (small, medium and large).

Owing to the importance of natural gas consumption in the sector, the size categories and fuel prices pertaining to natural gas are referred to here. When working out the average natural gas consumption and, therefore, the representative size of consumer we consider:

- The total natural gas consumption for the generation of heat and electricity, as sites will pay according to the scale of their consumption, including that consumed for the generation of electricity and indirect heat (steam).
- The number of sites consuming this natural gas

In total 50 sites accounted for the 12,300,000MWh of natural gas consumption, implying an average consumption of ~246,000MWh of natural gas p.a. This would place the average paper site consuming natural gas for the generation of direct heat in the 'large' category, paying 2.403 p/kWh (excl. CCL).

10.2.3. Specific Energy Consumption and Specific CO_{2e} Emissions

Table 57 shows the specific energy consumption and specific CO_{2e} emissions for the direct drying processes being carried out in each of the four sub-sectors.

Table 57 Specific Energy Consumption (From data provided for 2012 by CPI)

Direct Heat Consuming Process	Specific Energy Consumption (MWh/tonne)	Specific CO_{2e} Emissions (tCO_{2e}/tonne)
Tissue	1.220	0.226
Newsprint & Graphics	0.148	0.027
Packaging	0.124	0.023
Speciality	2.306	0.427

The high relative energy consumption and CO_{2e} emissions are evident in the tissue sector, where generated hot air not only performs a drying role with a product conditioning role. A

---

[121] Although biomass is consumed for the generation of steam used in cylinder dryers and Yankee Dryers. There is also the consumption of biogas from anaerobic digestion of effluent waste from the paper making process at one site. AD would be confined to sites where there is a high effluent concentration, which will tend to be sites using recycled paper. At the one site with AD, biogas only accounts for a very small proportion of gas demand (~1% of fuel for heat generation), with none of this biogas burned for direct heat generation.

number of direct heat drying processes are carried out in the Speciality sector and this makes it difficult to comment on the specific consumption and emissions for this sub-sector.

10.2.4. Heat Load Factors

While the fuel consumption for the generation of direct heat is known for each sub-sector, the sector association has not been able to provide information on burner capacity that would allow load factors to be determined at his stage. However, upon speaking with the Confederation of Paper Industries (CPI) in respect of the tissue sub-sector, they have indicated that the demand for heat can range from 95% of the year for larger mills to 50% for smaller mills. Overall, on a weighted energy consumption basis, heat would be required for an average of 80-85% of the year[122].

10.3. Types of Burner Used

It was only possible to determine the burner type for some of the burners associated with Dryer Hoods (See Section 10.3). These burners were found to Air Blast Burners.

10.4. Technical Potential for Candidate Fuel Consumption and Barriers

10.4.1. Suitability of Candidate Fuels

As explained above, over 75% of fuel for direct heat in the paper sector is used within the tissue sub-sector. Suitable candidate fuels will only be those that burn cleanly. Therefore, the candidate fuels being considered in this study, which are suitable for the paper sector, are considered to be biogas, hydrogen and syngas. The intimate contact between the combustion products and the product and the stringent hygiene requirements of the product preclude the other candidate fuels.

10.4.2. Technical Barriers to Candidate Fuel Use

Same as per pre-mix burners in general, e.g. getting more volume of fuel gas in to maintain burner power, adjustments required to alter the stoichiometric fuel:air mix in order to achieve complete combustion and altering the flow rate from the burner nozzle in order to avoid burn-back with candidate fuels with hydrogen content.

10.4.3. Technical Potential for Candidate Fuel Use

From feedback from burner suppliers we will assume that for the candidate gaseous fuels to be burned complete burner replacement will be required across all processes. We further assume that when that is the case the candidate fuels can supply all of the process heat.

---

[122] If the assumed load factor is too high, then this would lead to and underestimate of the total burner capacity, and vice versa. This would, therefore, lead to an underestimate for the total burner replacement cost in the cost effective modelling

10.4.4. Cost Effective Potential for Candidate Fuel Use

The results of the cost effective modelling for the Tissue drying process are presented below in

Table 58 Paper Tissue Drying - Modelling Results for Syngas- Waste, Syngas – Biomass and Hydrogen

	Fuel Consumption (MWh)	Annual CO_{2e} Emissions (tCO_{2e})	30 year CO_{2e} Emissions (tCO_{2e})
Counterfactual	1,011,000	186,125	5,211,503

New Technol./ Candidate Fuel	Gate Fee (£/tonne)	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[123]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m)[124]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[125]
Syngas - Waste	40	1,011,000	-30,330	120,697	3,523,007	158	23	44.87	20.29
	0	1,011,000	-30,330	120,697	3,523,007	244	254	69.36	33.07
	-40	1,011,000	-30,330	120,697	3,523,007	350	537	99.30	48.69
Syngas - Biomass	N/A	1,011,000	-30,330	171,045	4,932,745	300	403	60.81	40.08

---

[123] Excluding cost of carbon

[124] Excluding cost of carbon

[125] Including cost of carbon

New Technol./ Candidate Fuel	Scenario	Annual Candidate Fuel Consumption (MWh)	Annual Energy Saving Relative to Counterfactual (MWh)	Annual CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	30 Year CO_{2e} Savings Relative to Counterfactual (tCO_{2e})	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 12% (£m)[126]	Cost Relative to Counterfactual Over 30 Year Appraisal Period – DR = 3.5% (£m)[127]	Implied Cost of Abatement – DR = 12% (£/tCO_{2e})	Subsidy Implied per Unit Candidate Fuel (£/MWh)[128]
Hydrogen	BROWN	1,011,000	0	-96,233	-2,694,533	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	MIXED	1,011,000	0	-96,233	-2,087,462	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase
	GREEN	1,011,000	0	-254,927	-761,243	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase	N/A – Emissions Increase

---

[126] Excluding cost of carbon

[127] Excluding cost of carbon

[128] Including cost of carbon

	Scenario	CO_{2e} Saving Relative to Counterfactual - 30 Year Appraisal Period (tCO_{2e})	Year in Which New Technology Would Begin to Generate CO_{2e} Savings	Annual CO_{2e} Saving Relative to Counterfactual in 30 years' time (2043) (tCO_{2e})	Year from Which Investment Would Generate CO_{2e} Savings Over 30 year Period Relative to Counterfactual
Hydrogen	BROWN	-2,694,533	Never	-96,233	Never
	MIXED	-2,087,462	Early 2040s	-4,467	~2029
	GREEN	-761,243	2029	131,545	~2017

The results for the tissue drying process presented in Table 58 are in line with those presented for the other processes for which syngas and hydrogen are considered candidate fuels. In summary, syngas from both sources (waste and biomass) are more expensive than the counterfactual with the implied need for subsidies in the range £20-£40/MWh of delivered syngas necessary to close the cost gap with the counterfactual over the 30 year assessment period.

As is seen above for all of the other processes for which hydrogen is considered a candidate fuel, the use of hydrogen represents a CO_{2e} emissions increase over the counterfactual over the 30 year assessment period. The availability of CCS on SMR and the decarbonisation of the grid would have to occur earlier than is assumed in this study for net CO_{2e} savings to result over the 30 year assessment period.

In order to put the hydrogen scenarios into context, further information is supplied at the bottom of Table 58 for each of the Brown, Mixed and Green hydrogen scenarios. This additional information shows the first year in which each scenario would generate annual CO_{2e} savings relative to the counterfactual, the annual saving that would be generated at the end of a 30 year assessment period which starts now, i.e. the annual savings in 2043 and the year in which the hydrogen project would have to be invested in if it were to generate net CO_{2e} savings over a 30 year assessment period. For the Brown scenario, CO_{2e} savings are never achieved relative to the counterfactual. Annual savings over the counterfactual would begin in the early 2040s for the Mixed scenario and in 2029 for the Green scenario. Net CO_{2e} savings over a 30 year assessment period would occur for the Green scenario if investment was made in 2017, while for the Mixed scenario, investment would have to start in ~ 2029.

11. Monitoring of Direct Heat

An important consideration in whether the RHI should be extended to heat supplied directly to process is whether the quantity of heat can be satisfactorily monitored, since RHI payments would be made against this value. The nature of the monitoring – whether it is to be directly metered or determined by benchmark approaches, needs to be considered in the light of the technology approach.

We consider there are three possible core methods for determining the quantity of renewable heat sent directly to a process. These possible methods are:

(1) The measurement of the direct heat.

(2) The measurement of the fuel used to generate the heat.

(3) The measurement of the product outputs of the heat consuming processes.

We have explored the technical advantages and disadvantages of each of these. The associated costs are to be considered in the next stage of this project.

11.1. Method 1 Measurement of Direct Heat

The large variety of processes identified during this study emphasises the challenge of robustly metering heat generated and consumed by direct firing applications. The most direct and proven method of direct heat measurement is that put forward in the guidance for metering of direct heat, adopted in DECC's Combined Heat and Power Quality Assurance (CHPQA) programme[129]. This method is sufficiently robust to meet CHPQA requirements, where accurate determination of energy flows is necessary for assessing scheme qualification for available fiscal benefits.

This method relies on determining gas mass flows and temperatures at key points across the process. It would be suitable for direct use of hot gases used for drying purposes. The useful energy extracted from the hot gases involves, as a minimum, measuring the gas temperature before utilisation, the gas temperature in the flue leaving the process plant and the mass flow rate of gases. As such only processes with clear boundaries around them and identifiable points for energy flow into and out of the boundary are amenable to this methodology.

A number of issues need to be considered with this approach to ensure good quality measurements:

11.1.1. Location of thermocouples

---

[129] Apart from the guidance set out in CHPQA guidance the authors are not aware of any best practice guidance on measurement of direct heat.

Thermocouples must be installed at a point where they measure the gas temperature without interference from other influences. In particular, it is very important to avoid any impingement from a burner flame on to the thermocouple, or significant radiant effects from a refractory lining. It is also important to ensure that the measurements made are representative of true gas temperatures evenly spread across the duct. This may require several thermocouples to measure the temperature across the duct. Depending upon the dimensions of the duct, it may be necessary for cross duct temperatures to be mapped to an agreed matrix by and independent 3rd party. Thermocouples should also be calibrated at agreed intervals in order to ensure that the accuracy of measurement is acceptable.

11.1.2. Location of flow measurement devices

Similarly to thermocouples, the necessary devices installed to measure air flow rates must be located in the fully developed flow stream to ensure minimum uncertainties for the measurements made. There should be provision of long, straight lengths of duct before and after the measuring location. Significant guidance is available on how to measure flow and the location of suitable measurement locations, and in particular standard methods are available, such as BS EN ISO 16911-2:2013 (Determination of velocity and volumetric flow in ducts — Part 2: Automated measuring systems). Again, depending upon the configuration of ducts, it may be necessary for a 3rd party to verify that he positioning of flow measurement devices is consistent with accurate flow measurement. If this method were adopted, tailored guidance would have to be developed in respect of measuring flow and situation of flow devices.

11.1.3. Suitability of flow measurement devices

The flow measurement device must be appropriate to the characteristics of the fluid being measured. For example, if measurements are to be made in an gas stream that is carrying high concentrations of entrained particulate material, then the device must be capable of reliably measuring in these conditions, and may require automatic air purge systems and appropriate data manipulation (to remove time periods when purge systems are operating). A variety of devices are available to measure flow. Options include meters using pitot-static tubes, orifice plates, venturis, Coriolis, vortex shedding, turbine, magnetic, ultrasonic, positive displacement and thermal dispersion.

11.1.4. Measurement of composition

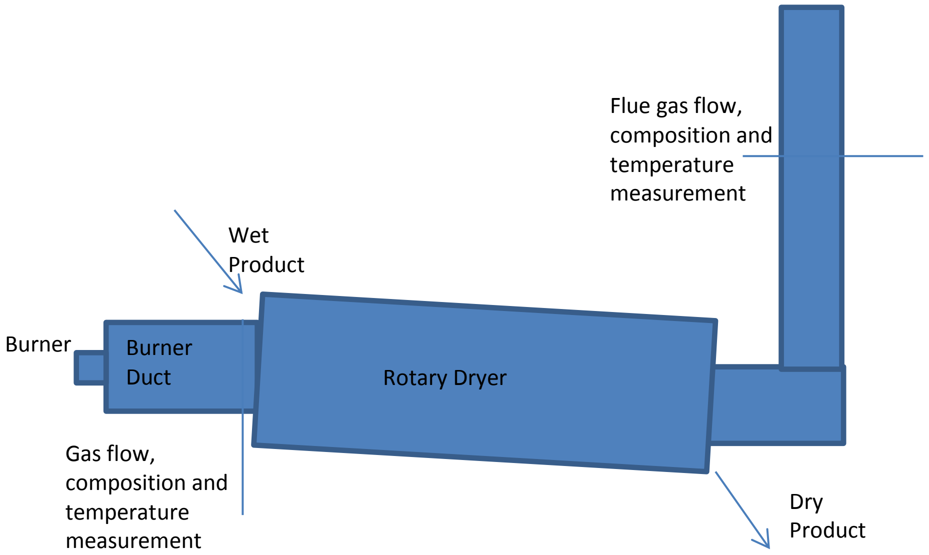
Where measurement of the composition of the process air is required, it should be undertaken by appropriate continuous measurement. This should be located in ducts in the process where it can be proven that the location is representative of the air passing through the heat utilisation step in the process. A range of devices are available for the continuous measurement of oxygen and moisture content.

11.1.5. Measurement of energy input and output

It will be required to understand the energy input into the process, and so measurement of the this will be required. This is achieved by volume and temperature measurement of hot combustion gases and air entering the process.

All devices utilised must demonstrate installation in accordance with manufacturer's instructions, operation to appropriate reference standard methods, and calibration to National Standards.

Figure 4 Example location of measure points for Method 1



Where only a proportion of the heat from combustion of the fuels is used for direct heating it is likely that the remaining exhaust will be used for some other duty such as steam generation or water heating. In this case an energy balance that includes the boiler duty can be used to derive the direct heating duty.

Modification of this method would be necessary to cover processes such as Fired Heaters, where the measurement of the process fluid temperature can be added to understand the sensible heat added to the fluid. To do this evaluation of the specific heat capacity of the process fluid will be necessary. Considerable monitoring across fired heaters is already in place for operational control and it is probable that little modification would be necessary to affect appropriate metering. However, this would have to be investigated further and is outside the scope of this study.

Relative Advantages

The actual useful heat absorbed in the process is determined and the RHI payment is made against this.

Minimising the heat flow from the process (i.e. heat losses) is incentivised as this increases the heat consumed in the process per unit of fuel input and, therefore, any potential RHI payment per unit of fuel consumed.

This method would fit within the current legal framework of the RHI, which requires direct measurement of heat.

Relative Disadvantages

Measurement is susceptible to uncertainty if thermocouple locations are not properly chosen to capture variations of temperature across the duct. Detailed guidelines will need to be developed by the RHI administrator, Ofgem, to cover appropriate locations of thermocouples and flow meters.

Difficult to audit as in some cases access to thermocouples can be difficult.

The actual useful heat absorbed in a particular process under examination may not be best practice useful heat consumption per unit of product made. For example, the process may be operating efficiently from the point of view of minimising the waste heat leaving the process. However, the process may not be optimised from the point of view of throughout. If this is the case more useful heat (and therefore fuel) will be consumed than is strictly necessary. Making RHI payments on a quantity of heat determined in this way will not incentivise the optimisation of processes from a throughput point of view. However, other business drivers, such as maximising utilisation of the process, reduce the risk of this.

11.2. Method 2 Direct Measurement of Fuel Input (Fuel input benchmark method)

In this method, instead of undertaking to determine the energy content of the direct flows of gas supplying heat to process, the quantity of fuel inputs is used as a proxy for the energy flow. While simpler than direct measurement of heat, this method requires agreement on standard direct firing efficiency factors that would be used to turn fuel inputs into process heat consumption, which may need to vary appreciably across the different processes under consideration. This will require the identification of appropriate benchmarks against specific processes. It will also be necessary to calorific value of the fuel consumed.

We recommend that this method should use a heat benchmark figure when determining the useful heat, as follows:

Useful Heat (MWh) = Verified fuel input (MWh) x standard direct firing efficiency

Where the standard direct firing efficiency would be the agreed ratio of energy in the fuel that is actually consumed in the process to the energy in the fuel input to the process, i.e. discounting energy exiting the process.

The calorific value of the relevant fuel would have to be known. Factors for standard fuels exist. Fuel input for non-standard fuels could be verified using the monitoring and verification protocols used for EU ETS. The Cement sector currently combusts a number of non-standard waste fuels, but undertakes an agreed methodology for determining their energy content.

A direct firing efficiency is invoked to convert verified fuel input into useful heat, i.e. heat actually consumed in the process in question. We recognise that this factor will have to vary to account for the varying proportions of heat released during combustion that can be counted as useful heat. In some applications virtually all of the heat released during combustion can be counted as useful heat (e.g. fryers in the food industry) while in other applications only a proportion of this can be counted as useful heat (dryers), with the balance not used but rather exhausted. We believe that only allowing for useful heat provides an incentive for the balance of the heat released during combustion, currently unutilised, to be utilised, for example through heat recovery to displace fossil fuel consumption elsewhere or the generation of electricity. These factors should be a function of the process outlet temperature, and they could be in the range of 70% to 90%.

For example, suppose that for the cement clinker manufacturing process it is agreed that only 70% of the energy in the fuel can be utilised in the process, implying that 30% has to pass up the stack (exit the process) and suppose that two fuels of used, Fuel 1 and Fuel 2, then the useful heat would be determined as follows:

Useful Heat (MWh) = [(Fuel 1 (tonnes) x GCV Fuel 1 (MWh/tonne) + Fuel 2 (tonnes) x GCV Fuel 2 (MWh/tonne)] x 0.7

In order to minimise complexity the number of different direct firing efficiency factors should be kept to a minimum, but not be so small as to inadequately cover the range of direct firing activities.

Relative Advantages

Potentially easy to administer and verify.

Potentially complex and expensive mass flow and temperature monitoring equipment is avoided.

Relative Disadvantages

A standard direct firing efficiency has to be determined and agreed for each application/sector process. It is critical to establish conversion factors that incentivise efficiency. If set too high inefficient processes will be over incentivised. If set too low then efficient processes will be penalised. These factors would have to be agreed with stakeholders. Sources of information that could be drawn upon for determining these factors could be BAT documents or work conducted to set emissions benchmark values for EU ETS phase three, where the specific processes in question are covered in those documents and studies.

The issue with not incentivising the optimisation of processes from the point of view of throughput (see above) remains. This would be addressed under Method 3, which would require reference to the physical product throughput of the process.

This method would not fit within the current legal framework of the RHI, which requires direct measurement of heat. This method utilises a direct measurement of the chemical energy within the fuel input to the process and a standard factor. Accordingly, RHI regulation will need to be amended to allow for this method.

11.3. Method 3 Direct Measurement of Product Output (Product benchmark method)

In this method the quantity of product emerging from the heat consuming process is measured and the direct heat deemed necessary for its manufacture is determined. The heat deemed necessary for manufacture should be based on benchmark values, such as those established for the allocation of EUAs under Phase III of the Emissions Trading Directive or best practice values quoted in BAT documents in which the process is covered.

Product benchmarks have been established for a significant proportion of the product outputs for the heat consuming processes under consideration in this work. Such a method has the advantage that it incentivises the efficient generation and consumption of renewable heat, as the operator of the process will, regardless of how efficiently he operates, only receive benefit for a quantity of heat consumption that is equivalent best practice for the product he is making. Benchmarks are generally based on the average of the best 10% of performing installations.

For example, in the case of cement clinker production, according to the BAT for cement and lime production[130], the best practice performance for clinker production is about 3,000 MJ/tonne clinker (8.33 MWh/tonne clinker). Therefore, useful heat could be determined as follows:

Useful Heat (MWh) = Clinker Production (tonne) x 8.33 MWh/tonne clinker

Relative Advantages

The measurement of activity (product throughout) would in many cases be more straightforward than with metering the actual quantity of useful heat consumed.

Both best practice thermal efficiency and productivity is incentivised.

Relative Disadvantages

Suitable benchmark values will only be available where direct emissions for the product under consideration are fuel related emissions and where the product benchmark was not developed taking a ‘system’ view of the production of the product, where the benchmark may reflect energy consumption from a number of processes, not just the direct heat consuming process of interest. As product benchmarks are expressed in terms of tCO_{2e}/tonne product, these would have to be converted into a fuel input equivalent and so attention would have to be given to the fuel types generating the benchmark in the first place.

This method would not fit within the current legal framework of the RHI, which requires direct measurement of heat. This method utilises a direct measurement of the chemical energy within the fuel input to the process and the level of production of the product in question. Accordingly, RHI regulation will need to be amended to allow for this method.

For example, suppose a direct heat consuming process only produces one product (Product A) and Product A’s production only involves the consumption of direct heat. Product A has been assigned an EU ETS Phase III product benchmark of 0.185 tCO2/tonne based upon the 10% best performing producers of Product A and, overall, these producers consumed only natural gas and gas oil in the production of Product A, with a split 75% Natural Gas and 25% Gas Oil.

The CO_2 factor for natural gas is 0.1841 kgCO2/kWh and for Gas Oil is 0.2777 $kgCO_2$/kWh.

The weighted CO_2 factor for the fuels used at the 10% best performing producers is: (75% x 0.1841 kgCO2/kWh) + (25% x 0.2777 kgCO2/kWh) = 0.2075 kgCO2/kWh.

Therefore,

Useful Heat (MWh)/ Product A (tonne) = (1000 $kgCO_2/tCO_2$ x 0.185 tCO_2/tonne)/(0.2075 $kgCO_2$/kWh x 1000 kWh/MWh) = 0.892 MWh/tonne Product A

If production of Product A was 1,000 tonne, then

Useful Heat (MWh) = 0.892 MWh/tonne Product A x 1,000 tonne Product A = 892 MWh

If the specific process in question now burns, for example, syngas from waste (50%) and natural gas (50%), the useful heat on which the RHI might be paid could be:

50% x 892 MWh = 446 MWh

---

[130] Best Available Techniques (BAT) for the Production of cement, Lime and Magnesium Oxide, p. 47

11.4. Protocol

To evaluate the relative merits and demerits of each of the three candidate methods of monitoring heat against the key direct heat consuming processes, a hierarchy process is followed.

The exercise is to consider which of the potential monitoring methods is suitable for use with the process being considered.

The Direct Metering method would be technically possible if the following are true:

(i) The energy content of the heat contained in the hot air entering the process can be metered

(ii) The energy content of all the fuel inputs to the process can be metered

(iii) If applicable, the energy content of the renewable fuel inputs to the process can be metered separately from the other fuel inputs

(iv) The quantity of heat contained in the hot gases leaving the process can be determined.

Direct heat processes proving technically incompatible with the Direct Metering method could be technically compatible with the Fuel Input Benchmark method if the following are true:

(i) The energy content of all fuel inputs to the process can be metered

(ii) The energy content of the renewable fuel input to the process can be metered and

(iii) A standard direct firing efficiency can be determined and agreed in respect of the direct firing process under consideration.

Direct heat processes proving technically incompatible with the Fuel Input Benchmark method could be technically compatible with a Product Benchmark method if the following are true:

(i) The energy content of all fuel inputs to the process can be metered

(ii) If applicable, the energy content of the renewable fuel inputs to the process can be metered separately from the other fuel inputs

(iii) the quantity of a product leaving the heat consuming process can be determined and

(iv) An agreed standard direct firing efficiency can be agreed for the process, where the standard direct firing efficiency would the ratio of energy in the fuel that is actually consumed in the process to the energy to the fuel input to the process, i.e. discounting the energy exiting the process.

11.5. Recommendation

Under the assumption that any method eventually adopted to determine the quantity of direct heat consumed in a process, on which a subsidy might be paid, would have to be the same across all processes, a method will have to be adopted that requires for its operation data that can be available for all processes and which captures the greatest number of advantages.

While the Direct Metering method is the most robust in determining the actual quantity of heat consumed in the process, an initial assessment indicates that this method will not work for all of the significant processes investigated in this study. For a number of processes, it is not expected that it will be possible to determine the energy content of the gas streams entering the process. Practical constraints preventing this include:

1. Very high process input temperatures rendering the lifetime of thermocouples to measure input temperatures unacceptably short.

2. Process configurations preventing the ‘fully developed’ gas stream entering the process from being accessed and, therefore, measured.

These technical issues are not expected to apply to the same extent for the determination of the energy content of hot gas streams leaving the process[131], as temperatures of air leaving the process will tend to be lower and exhaust monitoring will facilitate the measurement of mass flows from the process. This indicates that the component of direct heat consumption determination that involves metering quantity of heat leaving the process could be retained.

It is further anticipated that the determination of heat consumption using already derived benchmark values will prove impractical to apply in all cases. There are two main difficulties anticipated:

The main source of such benchmark values are the product CO_{2e} emission benchmarks developed for EU ETS. However, if a direct heat consuming process is not one of those for which a product benchmark has been derived, then there will be no reference to use for determination of the best practice CO_{2e} emissions and, by extension, heat consumption.

Many of the product benchmarks have been developed using a ‘system’ approach, whereby emissions from a number of heat consuming processes (and also process emissions for some processes) required for the production of the product are included in the benchmark. As seen above, a number of direct heat consuming processes may be required for the production of a product and it is necessary to know a benchmark value just for the process to which a renewable fuel might be consumed, not all processes associated with production of a product. Examples of these difficulties include[132]:

- One product benchmark for grey cement, when the benchmark will include process emissions and emissions from fuel consumption for both calcination and clinker production. As discussed above, on some sites calcination and clinker production takes place in discrete processes, each with its separate fuel feed.
- One product benchmark for container glass, which includes emissions associated with fuel use for melting, forming and annealing, when in practice these are separate processes with their own, discrete fuel consumption.
- Product benchmarks for different types of paper and board production (Newsprint, Tissue etc.) when the emissions for this include emissions from fuel consumed for the generation of steam (indirect) heat.

Given the above, we recommend that the feasibility of using a hybrid of the Direct Metering (Method 1) and Fuel Input (Method 2) approaches should be investigated further for specific applications. Such an approach would retain the direct measurement of heat leaving the process, but would rely upon metering of the fuel input to the process as the means of determining the energy input to the process. This hybrid approach would take advantage of instrumentation already in place and reduce the complexity of and technical challenges associated with additional instrumentation, should this be needed. This hybrid approach would incentivise the minimisation of heat leaving the process as waste heat in the form of hot gas, but not necessarily heat lost through other mechanisms, such as through structural losses. However, this method would not fit within the current legal framework of the RHI, which requires direct measurement of heat.

---

[131] It is anticipated that in many cases the equipment to do this is already in place because of emissions monitoring requirements.

[132] 2011D0278 — EN — 07.09.2012 — 002.001 — 36 Annex I Product Benchmarks

If this investigation reveals that the quantity of heat leaving a particular process cannot be directly measured, and the process produces a ‘standard product’, then Method 3 could be considered.

11.6. Dual Use Fuels

Fuels sent to process can perform the role of energy carrier or chemical feedstock. An example of this is the use of carbon rich fuels (coal and coke) in the blast furnace at an integrated steel site. These fuels both combust for the generation of heat and act as a chemical reductant of iron ore or to iron. As such, the view may be taken that not all of the energy content of the fuel to the blast furnace is for the generation of heat. If this view is taken and a subsidy is only to be applied to fuel for the generation of heat, an agreed convention will have to be arrived at for apportioning the fuel input to the heat generation component and the chemical reductant component. In theory, doing this accurately would require knowledge of the carbon content of the fuel input, iron ore input and liquid iron output over the period of time under consideration. These complications have led to a simplified view being taken for Climate Change Levy (CCL) purposes, whereby all coke fed to blast furnaces is exempt from the CCL. Perhaps a similar approach can be considered for the RHI.

Dual use fuel issues may arise with other fuels in other processes. For example, the use of synthesis gas as both a chemical feedstock in the chemical sector and as a source of heat.

11.7. Measurement Uncertainty Considerations

The uncertainty of a measurement can be defined as the range of values within which there is a high probability (>98%) that the true value of a measured or calculated value lies.

The expression of uncertainty provides an indicator of the quality of the monitoring of performance or heat utilisation. It can be derived both for individually metered components of a measurement, and for values derived by calculation. A robust method for these derivations has been in operation on DECC’s CHPQA programme for some years.

For metered values, the uncertainty of individual measuring components can be confirmed by manufacturer’s specifications at installation, meter data sheets, or by calibration against standard methods. These values should be regularly confirmed by calibration (frequencies based on manufacturer’s specifications or standard methods).

In order for a measurement to be deemed best practice, individual metered inputs and outputs and calculated values, should be determined within an uncertainty that falls within a range of acceptability. Acceptable uncertainty would be better than 98%.

If a benchmark method is considered, further work would have to be undertaken to determine the uncertainty associated with the benchmark value.

12. Analysis and Conclusions

12.1. Extent of Direct Heat Consumption in the Sectors

Table 59 Relative quantities of fuel consumed for the generation of direct heat in the eight industrial sectors of interest

Industrial Sector	Fuel Consumption for Heat (MWh)	Fuel Consumption for Direct Heat (MWh)	Associated CO_{2e} Emissions for Direct Heat (tCO_{2e})	Year
Iron and Steel	67,921,055[133]	59,316,242[134]	20,958,660	2013
Refineries	59,151,000[135]	40,737,000[136]	13,302,402	2012
Chemicals	60,382,871[137]	41,242,522[138]	Insufficient information on fuel split	2006
Cement	6,842,435	6,842,435	1,646,312	2012
Glass	6,500,000	6,436,716	1,355,101	2012
Food and Drink	31,261,440[139]	4,789,000	889,877	2008
Ceramics	3,970,671	3,886,805	736,834	2012
Paper	9,900,000	1,338,000	247,811	2012
Total	**245,929,472**	**164,588,720**	**36,136,997,**	

---

[133] The fuel for indirect heat includes the double of counting of some energy, due to the consumption of by product gases such as blast furnace gas, coke oven gas and BOS gas for the generation of steam at CHP stations, which is subsequently consumed by steam producing processes. Unlike the case for direct heat, information is not available to allow this double counted energy to be removed. This would require knowledge of the quantity of by-product gas consumed in the CHP and the quantities of power and steam generated by the CHP. This information is not available to the authors

[134] Double counting of energy removed where appropriate. See section 4.5

[135] Includes fuel for power generation at refineries with embedded CHP

[136] Fuel for direct heat not supplied by sector. Fuel for direct heat estimated (see 8.1.1)

[137] Includes fuel for power generation but excludes fuel associated with steam imported from 3rd parties.

[138] Fuel for direct heat not supplied by sector. Fuel for direct heat estimated (see 9.1.1)

[139] Supplied by Food and Drink federation, but taken from Energy Consumption in the UK

Table 59 shows the relative importance of the industrial sectors under consideration in this study, in terms of the magnitude of fuel consumption and CO_{2e} emissions associated with the generation of direct heat. As such, it indicates the sectors where a move towards renewable and low carbon fuels for the generation of direct heat would have the largest absolute effect upon CO_{2e} emissions. The relative size of the different direct heat consuming processes within each sector is given in the chapters dedicated to each sector.

12.2. Technical Potential for Candidate Fuel Consumption

12.2.1. Glass, Food and Drink, Ceramics and Paper

Throughout the analysis we have assumed that where the incumbent fuel is gaseous, the candidate renewable or low carbon fuel must also be gaseous. This is mainly driven by process requirements where the clean burn of a gaseous fuel is necessary so as not to affect the product coming into direct contact with the combustion products. This is certainly the case in Glass, Paper, Food and Drink and most of the Ceramics products and processes. It is expected to be the case in Chemicals, where the final product is intolerant of any particulate inclusions that would originate from a solid fuel. Solid biomass fuels also have technical limitations where the temperature of the direct heat consuming process must be high (>900°C), as ash melting from solid biomass can prevent temperatures above 900°C from being accessed. There are some processes in these sectors where the combination of process temperature and particulate tolerance are such that solid biomass could be a candidate fuel. An example of this is drying in the Ceramics heavy clay sub-sector, where relatively low temperatures are required and the final product (bricks, tiles etc.) may tolerate the formation of particulates on the product surface. However, the nature of the drying process is such that a flame is required and this can only be achieved through the burning of pulverised biomass in a burner. It has not been possible to obtain costs for such burners and so the cost effective potential for this relatively niche opportunity has not been explored. As such syngas from waste, syngas from biomass and hydrogen have been carried forward as technically compatible with the processes carried out in these sectors. Accordingly, the cost effectiveness of the use of these fuels has been evaluated for the main direct heat consuming processes in Glass, Food and Drink (Maltings sub-sector only), Ceramics and Paper.

It has not been possible to establish with certainty whether, and the extent to which, the gaseous candidate fuels can be used in incumbent burners without modifications. Some sectors have suggested that they consider it possible for relatively small levels of substitution (0-30%) to be possible without burner modification. However, feedback from burner manufacturers has indicated that it is not possible to burn syngas, hydrogen (or indeed un-upgraded biogas) without a wholesale change of the existing burner system. There has been similar uncertainty regarding whether, and the extent to which, the candidate gaseous fuels can be used in incumbent burners with modifications to the burner, but not burner replacement. If technical potential for this existed, the cost effectiveness of this potential would depend upon the costs of burner modification. It has not been possible to obtain these costs from burner manufacturers and suppliers, who have, in any case, maintained that complete burner replacement is necessary.

With the exception of flat glass melting, container glass melting and heavy clay firing, which require very high temperatures, we have assumed that each process in question can tolerate 100% of the heat demand being supplied by the candidate fuel. In the case of the aforementioned processes, the low calorific values of the candidate fuels (syngas and hydrogen) relative to the main fuel being displaced (natural gas) and the need to attain very high temperatures, leads to the assumption that 50% of the direct heat demand will have to continue coming from natural gas. In the case of heavy clay firing, this assumption is based upon actual practical experience with the combustion of syngas in ceramic kilns. In the case of glass melting, the assumption is adopted on the basis that very high temperatures are required in glass melting. However, this is a very complex area and the reasonableness of this assumption is likely to vary from process to process. The true technical potential to use the candidate fuels in the specific processes will depend upon a complex interaction between the properties of the fuel (GCV – which in turn determines the volume of combustion products flowing through the process, flame speed, flame luminosity etc.) and the process itself., This may only be determined by actual trial runs in situ, to confirm that there are not unsatisfactory changes in the quality of the product emerging from the process or to the throughput of the process, i.e. that the process can maintain an acceptable level of productivity. If there are unacceptable changes to either product quality or process throughput for a given level of candidate fuel use, then maintenance of that level of substitution would require changes to the process itself, for example installation of a new furnace or kiln. Compared with a burner replacement, that would be a substantial technical and financial undertaking.

In light of the above considerations, the analysis has proceeded on the basis that, with the exception of glass melting and heavy clay firing, there is 100% technical potential for syngas from waste, syngas from biomass and hydrogen to be used to supply direct heat to the other processes in the Glass, Maltings, Ceramics and Paper sectors. It is also assumed that burning syngas or hydrogen would require dedicated burners, and that dedicated natural gas burners would have to be retained as a back-up supply of direct heat, should the supply of the candidate fuel fail. The costs associated with this are discussed in 12.3.

12.2.2. Cement

The cement sector already obtains a proportion of its direct heat from biomass. This biomass comes from a variety of sources, including SRF, meat and bone meal, sludges and waste wood chip. The Cement sector is the only sector analysed in this study that currently uses renewable fuels to satisfy some of its direct heat demand. The sector has estimated that 18% of fuel demand for direct heat is satisfied by renewable fuels.

The overwhelming majority of fuel currently used in cement kilns is in solid form, with some relatively minor consumption of gaseous and liquid fuels. As such, the obvious candidate fuel to consider for cement kilns are the solid candidate fuels; Solid Recovered Fuel (SRF) and biomass. This is because cement sites are already set-up to handle, prepare and burn solid fuels in their current burner systems. Moreover, the clinker production process is particularly tolerant of solid fuels, owing to the ability of the clinker product to absorb the resulting ash. The clinker production process is also tolerant of waste fuels, owing to the very high temperatures and long residence times at these high temperatures. This leads to the destruction of potentially harmful species originating from the waste.

The process of clinker production in a cement kiln is a two stage process. In the first stage, heat is consumed to calcine limestone to create CaO (900°C). This is followed by heat being consumed to drive the reaction of CaO with other materials in the raw meal fed to the kiln to produce cement clinker (1400-1500°C). Depending upon the set up at the site, calcination may be carried out in the same kiln as clinker production, or may be carried out in a separate chamber called a pre-calciner. At sites with pre-calciners, about 50-70% of total fuel consumption takes place in the pre-calciner. Owing to the lower temperatures developed when solid biomass is burned in air, sites with pre-calciners lend themselves better to higher levels of biomass substitution. However, the unavoidable need for a proportion of the heat in the kiln to be at 1500°C, and for flame temperatures to be at about 2000°C for this to be attainable, places a limit on the extent to which biomass can substitute the current mix of fuels (see 6.2.1). This means that very high levels of biomass substitution, in the order of 80%, for example, would require alterations to the process. These alterations include the installation of pre-calciners where they are currently not in place, and the use of oxygen firing to raise the flame temperatures attained with biomass. These entail capital costs, which are discussed in 12.3 and in Appendix 6 – Cement Scenario Assumptions. Following discussions with the sector, it has been assumed that biomass substitution levels of 80% are possible, so long as the afore-mentioned investments take place. Substitution levels of 40% and 60% have also been considered for biomass and SRF, separately, where less significant investments are required. The biomass substituted is assumed to be waste wood chip.

12.2.3. Iron and Steel

When considering the analysis of potential for the Iron and Steel sector in this study, it should be kept in mind that only data for three companies has been made available. However, data from both of the two companies operating the very energy intensive primary Blast Furnace (BF)/Basic Oxygen Steelmaking (BOS) process have been made available. This means that the vast majority of the fuel consumed for the generation of direct heat falls within this study.

The primary BF/BOS process is a source of by-product gases with significant energy content. These by-product gases arise from the processes of making coke for the BF (Coke Oven Gas, COG), producing liquid iron in the BF (Blast Furnace Gas, BFG) and refining liquid iron into steel (Basic Oxygen Steelmaking, BOS gas). None of these gases are renewable as they all contain carbon that ultimately comes from mineral coal processed in the coke ovens. The possible uses of these gases are combustion on site for a useful purpose, flaring or transfer to another place for combustion. In all of these situations CO_{2e} emissions result, and so the most carbon efficient use of these fuels is for as much of them as possible to be combusted to supply useful heat, thereby displacing the consumption of other fossil fuels. Information from the sector relating to these gases indicates that where they are generated with the required properties, and there is a simultaneous demand for heat or power, they are combusted for a useful purpose. Consequently, we conclude that there is no significant additional potential for their consumption for the generation of direct heat for process. However, it is worth noting that in some cases, where they are flared because of an absence of heat demand, they could be used to generate more electricity than is currently the case. This would require the installation of additional electricity generation capacity.

Of far more significance is the Blast Furnace process, which, according to data supplied for this study, consumes about 80% of the fuel for direct heat in the iron and steel sector. As such, substitution of the incumbent fossil fuels used in this process warrant the most attention. These incumbent fuels are mineral coke, coal, BFG and some other, minor fuels. It is necessary for there to be a large carbon input to the blast furnace process in the form of any displacing fuel, as carbon is needed to act as both a source of heat and as a reducing agent for the iron ore fed to the blast furnace. This points to the use of biomass charcoal as the most appropriate candidate fuel substitution for this very significant energy consuming process. For technical reasons discussed in 4.4.1, the potential for biomass charcoal to displace mineral coke is unclear, but certainly warrants further investigation. However, research indicates that the coal input to the blast furnace could be replaced by biomass charcoal in a pulverised form injected into the blast furnace, albeit with some downside of reduced blast furnace productivity. As such, the cost effective potential for the complete replacement of coal in the blast furnace with biomass coke has been evaluated.

12.2.4. Refineries

The fuel consumption for direct heat has been estimated (see 8.1.1), rather than provided directly by UKPIA. These estimates indicate that over 95% of the fuel for direct heat is from the combustion of refinery gas and petroleum coke. Both these fuels are by-products of the petroleum refining activity and, if not combusted for a useful heat purpose, would have to be combusted and where possible used in boilers for steam raising. Estimates from ETS7s indicate that only about 4% of refinery gas is flared[140]. Overall, this suggests that the potential for candidate fuel consumption at refineries is very small relative to the overall fuel consumption for the generation of direct heat. This finding and the lack of sufficiently granular data prevented any further analysis of the Refineries sector.

12.2.5. Chemicals

As mentioned above, the fuel consumption for direct heat generation has been estimated from sector supplied data on direct fuel and imported steam, data sourced by the authors on the estimated fuel consumed by on site CHP in the chemicals sector and the application of a number of assumptions. These assumptions imply a high proportion of fuel consumption being associated with direct heat generation (about two-thirds). However, there are significant uncertainties associated with this and these are discussed in section 9.1.1.

Within the general organics sub-sector, manufactured fuel accounts for over 50% of direct fuel consumed. A large proportion of this will be refinery gas consumed at petrochemical sites adjacent to and integrated with oil refineries. Where this fuel is consumed in direct heat consuming processes, it is not susceptible to substitution with candidate fuels, as the refinery gas would be displaced and then consumed in another process at the chemical site, a process at the refinery, or be flared.

The lack of sufficiently granular data prevented further analysis of the Chemicals sector.

12.3. Costs of Candidate Fuel Consumption

The following sections summarise the costs likely to be experienced by operators in the relevant sectors as a result of moving to displace their incumbent fuels with the various, relevant candidate renewable and low carbon fuels.

12.3.1. Glass, Food and Drink, Ceramics and Paper

As has been explained previously, the predominant fuel used in these sectors is natural gas and consequently the candidate fuels are the gaseous renewable and low carbon fuels of: syngas from the gasification of waste, syngas from the gasification of biomass and hydrogen.

---

[140] Communicated to the authors by DECC statisticians.

12.3.1.1. Syngas – waste[141]

Counterfactual (Base Case)

In the counterfactual, the capital cost of natural gas burners is assumed to be £3,417 per MWth of capacity, and the maintenance cost of the natural gas burners is assumed to be 3% of the capital cost of the burners each year. This is set out in Appendix 2 – Burner Cost Assumptions.

New Technology

The main capital item is a gasifier. It is assumed that the capital cost of a gasifier is ~£1.71m per MWth of capacity to generate syngas. The origin of these assumed costs are set out in Appendix 1 – Gasifier Cost Assumptions. The gasifier is assumed to have an operating and maintenance cost (not including the cost of feedstock to the gasifier) of 4.5% of the capital cost of the gasifier each year. In order to guarantee the supply of syngas at times of maintenance, 130% of the gasifier capacity required to generate the demand for syngas is assumed. As such, it is assumed that the gasifier capacity is modular and, at any one time, 30% of the modules are down being cleaned.

The waste feedstock to the gasifier is assumed to have a range of costs (-£40/tonne, £0/tonne and +£40/tonne). The gasifier is assumed to be 78% efficient, in energy terms, at turning waste into syngas. The origin of these assumptions is set out in each sectors Appendix (e.g. Appendix 3 – Glass Scenario Assumptions).

Burners to burn syngas are assumed to have a capital cost of £15,599 per MWth of capacity. The maintenance cost of these burners is included in the maintenance of the gasifier. The assumptions behind this are set out in Appendix 2 – Burner Cost Assumptions.

Back up natural gas burners are assumed to be necessary and are included as a cost, as is the additional cost of electricity required to operator the gasifier.

12.3.2. Syngas – biomass

Counterfactual (Base Case)

In the counterfactual, the capital cost of natural gas burners is assumed to be £3,417 per MWth of capacity and the maintenance cost of the natural gas burners is assumed to be 3% of the capital cost of the burners each year. This is set out in Appendix 2 – Burner Cost Assumptions

New Technology

The main capital item is a gasifier. It is assumed that the capital cost of a gasifier is ~£1.71m per MWth of capacity to generate syngas. The origin of these assumed costs are set out in Appendix 1 – Gasifier Cost Assumptions. The gasifier is assumed to have an operating and maintenance cost (not including the cost of feedstock to the gasifier) of 4.5% of the capital cost of the gasifier each year. In order to guarantee the supply of syngas at times of maintenance, 130% of the gasifier capacity required to generate the demand for syngas is assumed. As such, it is assumed that the gasifier capacity is modular and, at any one time, 30% of the modules are down being cleaned.

The waste feedstock to the gasifier is assumed to cost £6.43 per MWh of waste wood chip, and the gasifier is assumed to be 78% efficient, in energy terms, at turning waste into syngas. The

---

[141] Detailed assumptions underpinning the modelling for these sectors are given the Appendices. Owing to the availability of more specific data on average burner capacities in heavy clay firing, the burner costs assumptions are different for this process than for the other processes examined. This is set out and explained in the Appendix for Cemarics.

origin of these assumptions is set out in each sector's respective Appendix (e.g. Appendix 3 – Glass Scenario Assumptions).

Burners to burn syngas are assumed to have a capital cost of £15,599 per MWth of capacity. The maintenance cost of these burners is included in the maintenance of the gasifier. The assumptions behind this are set out in Appendix 2 – Burner Cost Assumptions.

Back up natural gas burners are assumed to be necessary and are included as a cost, as is the additional cost of electricity required to operate the gasifier.

12.3.3. Hydrogen

Counterfactual (Base Case)

In the counterfactual, the capital cost of natural gas burners is assumed to be £3,417 per MWth of capacity and the maintenance cost of the natural gas burners is assumed to be 3% of the capital cost of the burners each year. The assumptions behind the cost of hydrogen burners are set out in Appendix 2.

New Technology

Burners to burn hydrogen are assumed to have a capital costs of £56,500 per MWth of capacity. The maintenance cost of these hydrogen burners is assumed to be 3% of the capex each year.

N.B. Cost effective modelling of the hydrogen opportunity has not been pursued since, for all hydrogen supply scenarios investigated, a CO_{2e} emissions increase results.

12.3.4. Cement

The opportunities investigated for Cement are moving from the current mix of fuels fed to the cement kilns to the following fuel mix:

- 60% Coal/ 40% Biomass
- 60% Coal/ 40% SRF
- 40% Coal/ 60% Biomass
- 40% Coal/ 60% SRF
- 20% Coal/ 80% Biomass
- 20% Coal/ 80% SRF

Counterfactual (Base Case)

The counterfactual is simply continuing to produce cement with the existing plant and mix of fuels.

New Technology

Depending upon the degree to which the existing fuel mix is displaced by biomass and SRF, a range of additional capital and operational costs (not including fuel costs) are incurred. For lower rates of SRF consumption, these are modest, as this fuel is already consumed in the sector (albeit at lower rates than those examined in the modelling), and so much of the existing storage and handling facilities are assumed to be adequate. However, at higher levels of SRF substitution, more significant capital costs are incurred. This is also the case for higher levels of biomass substitution. Lower levels of biomass substitution do incur additional capital costs as new storage and handling facilities are assumed to be needed for this fuel. Detailed assumptions behind the modelled scenarios are set out in Appendix 6 – Cement Scenario Assumptions.

12.3.5. Iron and Steel

The opportunity examined for the Iron and Steel sector is the displacement of pulverised coal injected into the blast furnace by pulverised biomass charcoal. There is unlikely to be further opportunity for charcoal to displace mineral coke fed to the blast furnace in the main change.

Counterfactual (Base Case)

The counterfactual is simply continuing to produce hot metal with the existing plant and mix of fuels

New Technology

It has not been possible to obtain capital costs relating to the use of pulverised charcoal (new storage, handling and processing plant), although it is likely that additional capital expenditure would be required for this opportunity to be pursued. Consequently, the existing equipment for storing, handling, processing and feeding to the blast furnace pulverised coal is assumed to be suitable for charcoal. Consequently, the new technology is replacing all pulverised coal fed to the blast furnace with pulverised charcoal.

Detailed assumptions are provided in Appendix 4 – Iron and Steel Scenario Assumptions.

12.4. Cost Effective Potential for Candidate Fuel Consumption

As discussed above, it has been possible to undertake cost effective potential analysis for six of the eight sectors of interest to this study. For five of these sectors the analysis has been carried out for the most significant direct heat consuming processes. This has been the approach taken for the Glass, Iron and Steel, Ceramics, Food and Drink and Paper sectors. For Cement, this has been carried out for all of the fuel for direct heat generation in the sector, as all direct heat is considered to be consumed in one process. All of the main results of interest are summarised in Appendix 11 – Summary of Results of Cost Effective Potential Analysis, and a full glossary of terms is also provided there.

12.4.1. Fuel Savings Relative to Counterfactual

For simplicity, our modelling has assumed that in order for the process to continue to operate with the required throughput, the same amount of energy must be delivered to the direct heat consuming process by the candidate fuel as by the incumbent fuels[142]. This means that the environmental benefit from the substitution is due only to the candidate fuel having a lower CO_{2e} intensity than the incumbent fuel(s). This is a reasonable assumption where all of the fuels delivering heat to the process are combusted. However, where the counterfactual includes electricity as a source of heat, and this is displaced by a candidate fuel in the new technology, it is likely that more energy will have to be delivered to the process in the new technology case than in the counterfactual case. This is because the use of electricity for the generation of heat

---

[142] However, it is acknowledged that for some processes combusting solid biomass, more energy might have to be put into the process to maintain the same productivity. This would occur if there were a higher moisture content in the candidate fuel than in the incumbent fuel, as would be the case with the displacement of coal by solid biomass in a cement kiln. However, the effect is not thought to be very large compared to other effects, and so has not been factored in the modelling.

is more efficient than the combustion of a fuel for the generation of heat, as the latter inevitably involves some of the energy of the fuel passing through the process unused in the form of exhaust gases, whereas heat generated from electricity will tend to pass out of the process only via losses through insulation. For the processes modelled, counterfactual cases where electricity is used are only found in the Melting, Lehr and Forehearth processes of the Container Glass sub-sector. This electricity is only assumed to be replaced by candidate fuel in the Forehearth and Lehr processes, as the electricity used in container glass melting plays a role that extends beyond supplying heat to the process and is assumed to be required in the new technology case. While electricity is used in relatively small proportions in the Container Glass subsector, the presence of this fuel in the counterfactual does have an impact on the cost-effectiveness of candidate fuel substitution, which is discussed below.

For processes where syngas is considered as a candidate fuel, there is additional electricity consumption in the new technology case. This is required for the operation of the gasifier in the new technology case, and is not required in the counterfactual.

12.4.2. The Case for Hydrogen

For none of the pairs of counterfactual and new technology scenarios is displacement of incumbent fuel with hydrogen environmentally beneficial in terms of CO_{2e} emissions. This is because, in all cases, replacement by hydrogen results in an increase in CO_{2e} emissions. This is a direct result of the assumptions made in this study relating to the hydrogen manufacturing processes assumed for the future (a mix of Steam Methane Reforming (SRM) and electrolysis), the availability of CCS applied to SRM, and the decarbonisation trajectory assumed for grid electricity. The assumptions are set out in detail in Appendix 9 – Assumptions Regarding Hydrogen CO2e Factors and Process.

In light of this finding, the cost effective potential for hydrogen displacement has not been pursued.

12.4.3. CO_{2e} Savings Relative to the Counterfactual

The CO_{2e} savings relative to the counterfactual over a 30 year appraisal will, in most cases, be a multiple of the annual CO_{2e} savings. However, for cases where electricity is consumed in the counterfactual and for two of the three scenarios examined for hydrogen, where hydrogen is consumed in the new technology, this will not be the case, as the CO_{2e} factors for both of these fuels decline over time. In the case of electricity this is due to a decarbonisation of the grid and in the case of hydrogen, depending upon the scenario being considered, this is due to a decarbonisation of the grid or an increased use of CCS, where the hydrogen is produced using SMR.

12.4.4. Cost Effective Potential of New Technologies

In terms of whether a new technology is cost effective, this is expressed relative to the counterfactual. This means that a new technology is cost effective if the Net Present Value (NPV) of the project to convert to the candidate fuel is less negative than the NPV of the project to continue with the incumbent fuels. The costs of these projects are set out in detail of the Appendices for each Sector that is modelled.

12.4.4.1. Fuels from Waste (SRF and Syngas from Waste)

A clear message from the cost effective modelling is that, where the candidate fuel is waste used directly in the process, without transformation into another fuel, the new technology is almost always cost effective relative to the counterfactual. The example here is the increased use of SRF directly in a cement kiln. A range of SRF substitution levels have been investigated, as well as a range of assumptions regarding the gate fee for the waste. In all but one scenario investigated, the new technology case was less expensive than the counterfactual. The exception was where the most unfavourable gate fee assumption was made (operator actually pays £40/tonne for receiving the waste) and the highest substitution rate, where appreciable capital expenditure is required to make possible the consumption of this higher level of waste. This is driven by the fact that, even at a gate fee of -£40/tonne, the cost of the SRF is less than the main fuel it displaces (coal).

Where waste is transformed into another fuel, as is the case where gasification of waste is used to produce syngas, the cost of the new technology is almost always more expensive than the counterfactual. The exception is where the counterfactual is comparatively expensive in itself, because it consumes relatively expensive electricity. However, this finding is made against a background of top down analysis. If individual site data on fuel demand were available and the analysis was done at this level, then the fact that unit costs of plant such as gasifiers and burners vary according to capacity would be brought into play. The relative costs of the new technology against the counterfactual could be quite different at the individual site level, and would be expected to produce a different result than at the aggregated, sector level.

12.4.4.2. Biomass

Another clear message from the cost effective modelling is that, where the candidate fuel involved is solid biomass, it is always the case that the new technology is not cost effective relative to the counterfactual. This applies whether the biomass is being gasified to produce syngas for consumption in sectors where the predominant incumbent fuel is natural gas (Glass, Ceramics, Food and Drink and Paper) or whether the biomass is being consumed as a solid fuel. This could be the case to a significant extent in the Cement sector, or as biomass charcoal in the Blast Furnace process in the Iron and Steel sector. This is a result of costs assumed for solid biomass in this study and how they compare against the incumbent fuels used, which is not favourably.

12.5. The Case for Support

When viewed at a high level, the results of the cost-effective modelling indicate, for a range of gate fee assumptions, the absence of a case for **financially** supporting the consumption of waste fuels, when these fuels are consumed directly in the process and do not require investment in technology to convert to a fuel in a more convenient form (e.g. gaseous form). This is the case for the consumption of SRF directly in cement kilns. However, for cases where waste fuel is consumed, but requires investment in technology to convert the waste into a gaseous fuel so that it can be used in the process in question, the modelling indicates that there is a case for financially supporting such applications.

The modelling indicates that, for the assumptions relating to biomass costs, there is also a case for financially supporting the use of biomass directly in direct heat consuming process or in cases where investment in technology is required to turn the biomass into a more convenient form of fuel.

Whether a new technology (candidate fuel) is cost effective relative to the counterfactual (incumbent fuel) is, in the main, invariant across processes. So, for example, where syngas-waste is not cost effective in Glass melting, it is also not cost effective in tissue drying. However, across the different processes, there are material differences in relative costs according to the load factors of the direct heat consuming processes and the types of fuel used in the counterfactual. Two examples are set out below:

Sub-sector = Maltings, Process = Kilning, New Technology = Syngas-waste or Syngas-biomass – This new technology was found to have a cost of abatement associated with it of less than £100/tCO_{2e}, for all processes with the exception of the kilning process in maltings. For this process, the cost of abatement was >£400/tCO_{2e}. This process is quite different from the others modelled in that it has a very low heat load factor (~13%) while in the other processes in the other sectors had load factors at 80% or greater. A low heat load factor means that the full capacity for generating heat is only used over a small proportion of the year, but the full capacity is nevertheless required. This means that the capital costs associated with providing heat from syngas-waste must be sufficient to cover the peak demand for heat, but the period of time over which the benefits can balance these costs is much shorter than for the processes with higher heat load factors. Overall, for a load factor as low as 13%, over a 30 year period of project appraisal, the benefits are insufficient to return a cost of abatement in a range that could be reasonably incentivised.

Sub-sector = Container Glass, Process = Lehr, New Technology = Syngas-waste – This New technology was found not to be cost-effective across all processes modelled, except the Lehr process in Container Glass, when a gate fee of £40/tonne was assumed. The main difference between this process and the other processes modelled against Syngas-waste is the fuel mix in the counterfactual. This fuel mix contains 30% electricity which is an expensive fuel relative to the other fuels used in the other counterfactuals (predominantly natural gas). This makes the counterfactual for the Lehr process more expensive per unit of fuel input, relative to the other counterfactual processes, to the point where the Syngas-waste new technology is actually the cheaper alternative. This underlines the point that the case for support is not a function of the absolute cost of the new technology but only a function of the relative costs of the new technology and counterfactual cases, and the latter cost is determined by the current mix of fuels used in the process. The more expensive the incumbent fuels, the less pronounced is the financial case for support and vice versa.

This last point is further reinforced by the results for the Cement sector where the new technology is an increasing share of solid biomass against a counterfactual with a 52% share of coal and a range of waste fuels. Coal, being a cheap fuel, makes the counterfactual relatively cheap to continue running. The remaining fuels in the counterfactual are mainly waste fuels. The cost of substituting biomass is quite dependent upon the gate fee assumption, even though this does not apply to biomass, as the gate fee assumption is a determining factor of the cost of the counterfactual. The higher the gate fee assumption, the more expensive it is to substitute biomass into cement kilns, and vice versa.

Considerations of support should go beyond the relative costs of new technologies and the counterfactual, and the quantity of CO_{2e} savings that could be 'purchased' by an incentive payment in respect of candidate fuel consumption. There are two additional factors that have a bearing on whether financial or other support may be warranted. These are:

1. Whether alternative options are available to decarbonise a process from the ones considered above

2. Whether the candidate fuels considered will be made available to the above processes in the quantities required, for the levels of decarbonisation required, of those processes to be achieved.

Where other opportunities to decarbonise a process are limited, then non-financial support for the candidate fuel may be warranted if the opportunity is (a) cheap relative to the counterfactual, (b) it is significant in terms of CO_{2e} savings potential, but (c) there are challenges associated with channelling the candidate fuel to the process in question. For example, the modelling in this study has indicated that it is cheaper to burn SRF in cement kilns at levels significantly higher than those currently used. This raises the question of why these higher levels have not already been achieved. If this were due to difficulty with cement manufacturers sourcing suitable SRF, then, assuming the overall availability of waste allows it, support to make this easier could be a very cost effective way for the UK to reduce its CO_{2e} emissions – the modelling indicates that each tonne of CO_{2e} saved by SRF substitution actually saves money. Support associated with promoting the increased direct use of biomass in cement clinker production would, according to the modelling, have to have a financial component to it and may have to include other support to encourage the channelling of biomass to this particular application, possibly leading to an overall more burdensome and less efficient means of decarbonising cement clinker production. As such, there is an argument for encouraging the channelling of waste towards applications where it can be used directly in generating process heat, because this will generate CO_{2e} savings at lowest cost.

Biomass might be better directed towards the direct heat consuming processes that cannot use waste directly, and therefore, cheaply (although waste gasification could compete with biomass gasification in those sectors where gaseous fuels must be used). Depending upon the relative costs of the main direct heat decarbonisation options available to glass melting and ceramics firing (electrification, increased use of biogas, increased use of syngas), support beyond the financial might be warranted to overcome biomass supply barriers and barriers associated with technical risk of operating gasification plant. This would be necessary if the use of syngas from biomass is a relatively cheap decarbonisation option relative to the other technical measures and these barriers are acute.

There are a range of non-technical barriers to candidate fuel use applying across the sectors considered in this study. These are considered below, together with suggested support mechanisms to address them.

12.6. Non-Technical Barriers to Candidate Fuel Consumption

If the incentives for the candidate fuels to be consumed for the generation of electricity (or indirect heat) are generous compared to any incentives that might be put in place to encourage the use of candidate fuels for the generation of direct heat, then the market for the candidate fuels might be skewed in such a way that candidate fuels are not made available for direct heat generation at a competitive price.

Sites where it is technically and economically feasible to switch to the candidate fuels may be reluctant to do so if the site believes that there are any uncertainties regarding the following:

- The reliability of technology using candidate fuels
- Ability of the site to cope with practicality of fuels deliveries (e.g. increased traffic movements)
- Security of supply of the fuel
- Availability of the fuel

- Sustainability of the fuel
- Price
- Calorific value of the fuel
- Certainty of Government policy
- In the case of waste, negative perception on the part of the public regarding the proximity of the waste and the product. This would be particularly acute in the food and drink sector where the handling of waste on the same site as the production of food might not be acceptable to the public
- Anxiety regarding the negotiation of contracts for the supply of the fuel, where such negotiations are outside the core business of the operator
- Anxiety regarding the technical challenges of operating plant, such as gasifiers, where this is outside the core business of the operator, although this would be mitigated by the availability of Energy Service Companies (ESCos) in the market with experience in this area.

These concerns about any particular fuel are mitigated if the heat consuming process can be run off a wide range of fuels, as is the case in the cement sector. However, where the process can only tolerate one or two fuels, then uncertainty over the above could lead to a “no invest“ decision in respect of the candidate fuel, even if the case is sound on technical and economic grounds.

Changing a process over to a new candidate fuel, which although on paper is technically feasible, will carry with it a degree of trepidation. Even small differences between the situation on the ground at a site considering the change and a site where there is documented proof of success, will raise the question: “Will it really work here?”. Large direct heat consuming processes, where the environmental prize associated with conversion is greatest, are usually the keystone of all site activities and the main source of revenue for a site. This is certainly the case in the processes of glass melting, liquid iron production and cement clinker manufacture, where there may be only one kiln or furnace on a site. The high fixed cost of these assets means that there is an economic imperative to run them as close to maximum capacity for as long as possible, meaning that any unexpected downtime can be particularly damaging to a company’s ability to fulfil orders, leading to financial and reputational damage. Under these circumstances, there will be a natural reluctance to alter a process unless there is a guarantee of success.

Many of the companies operating in the large direct heat consuming sectors are international with operations across a number of countries. That makes the pool of projects competing for finance large and varied. Against that background, any perceived uncertainty attaching to an energy project, such as those mentioned above, could easily make another project in another jurisdiction appear to be a better investment.

Part of any investment decision to use a candidate fuel will be based upon how the fuel will be treated from the point of view of CO_{2e} emissions. Where there is currently uncertainty about this, another variable is introduced into the decision-making matrix that can make the decision to switch more difficult to make[143].

For some sites in the Chemicals sector (petrochemicals), the production of syngas for generating direct process heat could compete with the production of syngas for use as a chemical feedstock. The use of syngas as a precursor of a range of petrochemical products

---

[143] Feedback from British Ceramic Confederation (BCC) on uncertainty about syngas fuels in this regard.

could make more economic sense to the site than combusting it for the generation of direct heat. The use of syngas as a chemical precursor would become more favourable if conventional sources of feedstock were to become more scarce.

The above barriers are mapped to the sectors considered in this study according to the impact each barrier has in each sector. This is presented in Table 60.

Table 60 Barriers to Candidate Fuel Consumption in Each Sector Considered

The table estimates the severity of the impact of the barriers on each sector (H = High, M = Medium, L = Low)

	Sector							
Barrier	**Glass**	**Iron & Steel**	**Ceramics**	**Cement**	**Food & Drink**	**Oil Refining**	**Chemicals**	**Paper & Pulp**
Reliability of technology using the candidate fuels	H	H	H	L	H	H	H	H
Ability of the site to cope with fuel deliveries	M	M	M	L	H	L	L	M
Security of supply	H	H	H	M	H	H	H	H
Availability of the fuel	H	H	H	M[144]H[145]	H	H	H	H
Sustainability of the fuel	H	H	H	M	H	H	H	H
Price	H	H	H	H	H	H	H	H
Calorific value	H	M	H	H	M	M	M	M
Certainty of Government policy	M	M	M	M	M	M	M	M
Negative public perception of waste	M	M	M	L	H	M	M	M

---

[144] For waste

[145] For biomass

Anxiety regarding negotiation of contracts	M	M	M	L	H	M	M	M
Anxiety regarding technical challenge of new plant	M	M	M	L	H	M	M	M
	Sector							
	Glass	**Iron & Steel**	**Ceramics**	**Cement**	**Food & Drink**	**Oil Refining**	**Chemicals**	**Paper & Pulp**
Anxiety over applicability to the specific site	H	H	H	L	H	H	H	H
How the fuel will be treated for CO_{2e} emissions	M	M	M	M	M	M	M	M
Alternative use of fuel as a feedstock	L	L	L	L	L	M	M	L

The ratings of High, Medium and Low here are intended to show the relative importance of the barrier to each sector based on Ricardo-AEA's experience and understanding of the industries and do not refer to an absolute scale of importance.

Each of the barriers considered in Table 60 are discussed further and potential support measures aimed at overcoming these barriers are also presented in Table 61.

Table 61 Barriers to Candidate Fuel Uptake and Potential Support Measures

Barrier	Discussion	Potential Support Measures
Reliability of technology using the candidate fuels	An issue for most sectors given where only limited use of the fuels has been made. The exception is Cement where there is wider and longer experience of using the candidate fuels.	Support for R&D and demonstration projects applicable to the sector.
Ability of the site to cope with fuel deliveries	Increased traffic movements will affect particularly sectors with smaller rural sites, probably more Food & Drink than other sectors.	This could be mitigated through use of biogas in the natural gas supply or local networks.
Security of supply	These three issues are linked – the long term availability and security of supply of the candidate fuels is a key barrier to take up.	Government incentives that favour the use of the candidate fuels for direct heat in industry over other uses (e.g. electricity generation)
Availability of the fuel		
Sustainability of the fuel		
Price	This relates directly to the quantitative analysis we have carried out on financial barriers.	See the sections of the report on cost-effective potential for candidate fuel use.
Calorific value	The candidate fuels may have lower calorific value than natural gas (the fuel often being displaced), particularly biomass.	Financial incentives for processes that produce higher calorific value fuels from biomass, e.g. oxygen blown gasification.
Certainty of Government policy	The take up of candidate fuels will require support to overcome financial and other barriers. Industry will need to see long-term commitment for these support measures so that they can make major long-term financial decisions.	Long-term consistent policy support.
Negative public perception of	Mainly an issue for Food & Drink and public perception regarding the proximity of waste to the	This could be mitigated through use of biogas in the natural gas supply or local networks so the waste is not

Barrier	Discussion	Potential Support Measures
waste	product.	used on site, or remote generation of syngas and supply to the site.
Anxiety regarding negotiation of contracts	This is an anxiety where such negotiations are outside the core business of the operator, particularly for smaller organisations.	Support to the development of ESCos in the market with experience in this area.
Anxiety regarding technical challenge of new plant	This is an anxiety where the use of plant such as gasifiers is outside the core business of the operator.	Support to the development of ESCos in the market with experience in this area.
Anxiety over applicability to the specific site	Even small difference between the site and one where the fuel has been used will raise the questions 'Will it really work here?'	Support for R&D and demonstration projects applicable to the sector.
How the fuel will be treated for CO_{2e} emissions	Operators with emissions targets are concerned that the treatment of CO_{2e} of candidate fuels may change. This affects their decision to take up the fuel.	Long-term certainty of policy on CO_{2e} emissions treatment. (This does not necessarily mean the treatment is fixed but that operators know how it will change and when).
Alternative use of fuel as a feedstock	This is principally a concern for the Chemicals industry where syngas may be used as a feedstock precursor for a range of petrochemical products more economically than using it for direct heat.	Incentives to use syngas for direct heat which take into consideration both the extra cost relative to the incumbent fuel (natural gas) and the value of syngas as a chemical feedstock.

12.7. Avoiding Perverse Incentives

If a subsidy is made available on heat consumed directly which is generated from renewable sources, this could drive behaviour not necessarily consistent with the best environmental outcome. There are two main examples of this:

- Direct heat loads are fabricated in order to derive income from the subsidy. In order to guard against this it should be necessary for the site to demonstrate that the heat load is economically justifiable in its own right. A heat load can be regarded as economically justifiable if it does not exceed the actual demand for heat from the process concerned and the heat consumed by the process would be satisfied at market conditions by the generation of heat using conventional fuels.
- The direct heat consuming process is not optimised for energy efficiency and the quantity of heat consumed (on which a subsidy might be paid) is larger than it needs to be. This can be addressed via the methodology used for determining the quantity of heat actually consumed in the process. Candidate methods for doing this and their relative merits for driving optimisation of the energy efficiency of the process are discussed in 11.5.

12.8. Conclusions

Where gaseous fuels are currently consumed, with the exception of glass melting and ceramics firing, we have assumed that there is 100% technical potential for candidate fuels to be burned if there is a complete change of the burner system. In the case of glass melting and ceramic firing, the potential is set at 50% for the reasons discussed in these sectors' chapters and Appendices. The cost effective potential has been carried out for these technical potentials. Implicit in this assumption is another assumption that the characteristics of the candidate fuels are such that changes to the process itself are not required to maintain the same levels of product quality and process productivity. If such changes were necessary, then further, additional (and probably significant) costs would be associated with the use of the new technology. These additional costs could have a significant impact upon the cost effectiveness found in this study. Limiting the technical potential to 50% in glass melting and ceramic firing was specifically intended to avoid wider process change.

For the hydrogen production scenarios examined in this study, we conclude that hydrogen is an unattractive candidate fuel because its consumption leads to an increase in CO_{2e} emissions across all processes where it is considered a candidate fuel. On this basis, the cost effective potential for hydrogen consumption has not been pursued.

Unlike hydrogen, syngas from gasification of waste and from biomass always offer reductions in CO_{2e} relative to the counterfactual. However, with the exception of one process, neither is cost effective relative to the counterfactual.

For the processes where solid biomass could be a suitable candidate fuel for technical reasons (e.g. clinker production and in the blast furnace), we conclude that subsidies are necessary if they are to offer cheaper alternatives to the counterfactual.

The cost effectiveness and/or level of subsidy required to render a new technology cost effective is a function of both the load factor of the heat consuming process, and the present fuel mix in the counterfactual. Higher heat load factors and more expensive fuels used in the counterfactual tend towards increasing the cost effectiveness of the new technology, or point to lower subsidies being required to render a new technology cost effective relative to the counterfactual. Processes using gaseous fuels will tend to use natural gas as the incumbent fuel, and so the cost of counterfactual fuels across these processes will be similar per unit of heat required. As such, a candidate fuel that is cost effective across one of these processes will tend to be cost effective across all, unless there is a significant difference between heat load factors of the processes.

Processes using solid fuels in the counterfactual, which are therefore susceptible to substitution by solid biomass or waste fuels, can be very different in their counterfactual costs. Processes already using waste fuels or coal can have very low counterfactual fuel costs, making the consumption of renewable or low carbon fuels (or the consumption of greater proportions of renewable and low carbon fuels than is currently the case) expensive. We conclude that this implies a subsidy would need to be part of a support package.

A standard approach to determining the amount of heat consumed in a direct heat consuming process which is robust, and which has the greatest chance of being practicable across a large number of processes, has been proposed as a hybrid of Method 1 and Method 2 presented in Section 11.5. This requires at a minimum accurate metering in energy terms of the total fuel input to the process, the renewable or low carbon fuel input to the process and metering of the quantity of heat contained in the hot gases leaving the process.

The direct heat consuming processes examined in this industry would require a range of changes to them, or their ancillary processes and activities, to allow the burning for the first time (or increased burning) of the candidate fuels considered, thereby securing CO_{2e} savings. These changes range in complexity. For example:

- The installation of on-site gasifier technology and replacement of process burners (most extreme)
- Simply requiring the installation of new or additional fuel storage and handling systems
- Situations which involve no capital investment at all.

Under the current RHI Regulations not all of these changes would be considered an action trigging an incentive payment, in that they do not always involve putting into place new installations. In spite of this, there is still a cost gap between burning the candidate fuel and carrying out business as usual process, which could be overcome with an incentive payment. This implies that if the RHI were to be used to incentivise the use of candidate fuels in these direct heat consuming industrial processes, amendments to the RHI Regulations would be required.

12.9. Suggestions for Further Research Required

- Further investigation of technical potential for candidate gaseous fuels to be burned in incumbent (mainly natural gas) burners without modification. The assumption made in this study, that complete burner replacement is required, stems from burner manufacture feedback. Feedback from a more balanced range of sources should be sought.
- We have assumed that for processes where 100% substitution with a gaseous candidate fuel is possible, this can proceed without triggering wider process change. The technical correctness of this assumption should be further researched.
- Further work to establish the most likely trajectory of the gate fee for waste that can be burned directly in direct heat consuming processes or can be gasified to produce syngas, as there is significant uncertainty about this and the results presented in this study are sensitive to it.

- Bottom-up analysis from site level data to sense check aggregated modelling results obtained from process level (i.e. multi-site) perspective – unit costs of burners and gasifier depend upon the individual capacities of these.
- Further investigation of the non-technical barriers to candidate fuel uptake is required. This will verify the relative importance of these in terms of the CO_{2e} emissions savings at risk if not addressed, and formulate the details of the support mechanisms suggested in this study.
- Continuing with the work started in respect of the chemicals sector. This will result in it being characterised at least as well as the other sectors in terms of how much direct heat is consumed, and where it is consumed.
- Validate some of the key cost data underpinning the results of the cost effective modelling. In particular, the capital and maintenance costs associated with gasifiers (and how these scale with individual gasifier unit capacities) and natural gas, syngas and biogas burner costs (and how these also scale with capacity).
- Complete the modelling for charcoal substitution in the blast furnace by sourcing information on whether, and how much, additional capital cost would be required.
- It has been suggested that the assumptions used to derive the availability of biomass presented in Chapter 2 may be out of date. More recent research on this question should be sourced.
- Further work should be carried out to understand the likely availability and composition of waste for gasification in the future. This is important given other policies impacting upon waste availability. Availability of waste will determine its cost in the market, which will have an impact upon the cost effective modelling results presented in this study. Changes in the composition of waste will drive changes in the calorific value of syngas produced, which may affect costs if more expensive biomass feedstock is required to maintain syngas calorific value.
- Field investigations should be carried out to test the high level practicality of the proposed direct heat metering methodology at a number of sites operating the largest direct heat consuming processes investigated in this study. The other possible methods presented in Section 11 that could be used where the proposed method is impracticable should also be field tested. This would lead to a matrix of results, showing process against the requirements set out in Section 11.4.

Table 62 Further Work – Constructing Matrix of Process Compatibility against Proposed Heat metering Methodology Data Requirements

Process	Proposed Hybrid Methodology Data Requirements Met?		
	Measurement of Total Fuel Energy Input (Y/N)	Measurement of Candidate Fuel Energy Input (Y/N)	Quantity of Heat Contained in Hot Gases Leaving the Process (Y/N)
Glass melting	Y	Y	Y
Brick firing	Y	Y	Y
Cement Clinker Production	Y	Y	Y
Tissue Drying	Y	Y	?
Blast Furnace	Y	Y	?
Maltings Kilning	Y	Y	?

Processes with an “N” in any cell in Table 62 could then be tested against Method 3, and then against Method 1, which would be the most onerous and expensive. This will allow an understanding of the proportion of industrial direct heat that could be determined with ease for the purposes of the RHI and which might place more burdens on industry and the administration. This could take about 4 months.

Following this, actual demonstration of the proposed methodology could be undertaken for a period of 6 months each.

13. Appendix 1 – Gasifier Cost Assumptions

For larger gasifier projects we have used information from the Defra report “Advanced Thermal Treatment of Municipal Solid Waste report”[146].

This report provides come indicative capital costs for projects of two capacities, as follows:

Waste Gasification Capacity (ktpa)	**Capacity of Yielded Syngas (MWth)**	**Capex (£m)**
25	8	9
100	32	55

It is worth noting that, owing to the small number of operating facilities, it has been very difficult to get real operational data on Capex and data.

Also, projects where syngas can be used will have their demand expressed in terms of MWth and not tpa of waste fed to the gasifier. It has therefore been necessary to convert the above capacities into thermal equivalent in order to be relevant for the application under consideration. This has been done assuming that the waste is Refuse Derived Waste (RDF) and has a GCV of 13 MJ/kg and that the efficiency of the process of turning the energy content of the waste into energy content in the syngas is 78%. These assumptions have been kindly shared with Ricardo-AEA by New Earth Advanced Thermal.

There are also insufficient data points in the literature to make extrapolation from Capex for a known capacity to Capex for a capacity of interest for a particular project on any basis other than a pro-rata basis.

Consequently, to illustrate, to provide the capex for a syngas conversion project at a flat glass site requiring fuel at a rate of 49 MWth the following calculation is used:

Capex for 49MWth = Capex for 32 MWth x (49 MWth/32 MWth), or

Capex for 49 MWth = £55 m x (49 MWth/32 MWth) = £84 m

Each application will be subject to very specific conditions which will inevitably have an impact upon costs. We would recommend that these figures should be treated with an error margin of about 30%.

In the absence of cost data for gasifiers with a range of capacities, it will be assumed in the analysis that the Capex of £55m/32 MWth = £1.7 m/MWth applies across all cases. However, it should be kept in mind that the Capex per unit of capacity is likely to be higher for smaller capacity gasifiers. To further investigate the potential identified in this study, a bottom-up analysis at the individual site level could be undertaken. A site level analysis could use a Capex

---

[146] Advanced Thermal Treatment of Municipal Solid Wastes, February 2013

for the gasifier appropriate for the actual syngas demand at the site, assuming that a Capex for a gasifier of that that capacity is available.

14. Appendix 2 – Burner Cost Assumptions

As has been discussed above our steer from burner manufacturers has been that natural gas burners cannot be viably converted to burn the candidate gaseous fuels. Therefore, cost information relating to existing natural gas burners and bespoke burners set-up to burn the candidate fuels are required to do the cost analysis.

After receiving burner cost information from suppliers for natural gas, syngas, hydrogen and biogas, we have been able to develop the following tables showing burner cost against capacity (See Table 63). Burner manufacturers have given us their steer on whether and how many times more a burner for a candidate fuel will cost compared to a natural gas burner of the same capacity. These are given in the column “Cost Multiplier w.r.t. Natural Gas”.

Plotting burner cost against capacity allows a cost characteristic of burner costs to capacity to be determined that has subsequently been used to determine burner costs for burner capacities between points in the range.

Table 63 Indicative Prices of burners for Natural Gas, Syngas, Hydrogen and Biogas

Natural Gas				Syn. Gas				Hydrogen				Biogas		
Burner Capacity (kW)	Burner Price (£)	Price (£/kW)		Cost Multiplier w.r.t Natural Gas	Burner Price (£)	Price (£/kW)		Cost Multiplier w.r.t Natural Gas	Burner Price (£)	Price (£/kW)		Cost Multiplier w.r.t Natural Gas	Burner Price (£)	Price (£/kW)
150	2,000	13.3		8.0	16,000	106.7		20.0	40,000	266.7		3	6,000	40.0
800	3,500	4.4		7.7	26,845	33.6		19.6	68,593	85.7		3	10,500	13.1
2000	5,000	2.5		7.1	35,305	17.7		19.0	94,944	47.5		3	15,000	7.5
5000	12,000	2.4		5.5	66,457	13.3		17.5	209,592	41.9		3	36,000	7.2
10000	40,000	4.0		3.0	120,000	12.0		15.0	600,000	60.0		3	120,000	12.0
Straight Line Equation				Straight Line Equation				Straight Line Equation				Straight Line Equation		
X	3.8140	£/kW		X	10.3770			X	56.1400			X	11.4410	
C	-1,190	£		C	15,667			C	1,081			C	-3,572	

Burner Capacity (kW)	Cost (NG) (£)	Cost (Syngas) (£)	Cost (Hydrogen) (£)
3000	(3000*3.814)-1190 =10,252	(3000*10.3770)+15667 = 46,798	(3000*56.14)+1081 = 169,501
1000	10,252/3 = 3,417	46,798/3 = 15,599	169,501/3 = 56,500

Burner Capacity (kW)	Cost (NG) (£)	Cost (Syngas) (£)	Cost (Hydrogen) (£)
3000	10,252	46,798	169,501
1000	3,417	15,599	56,500

15. Appendix 3 – Glass Scenario Assumptions

Below we set out in detail how the cost model numbers are derived for the flat glass melting process.

Background

There are 5 flat glass furnaces, each with the following approximate burner capacity:

7 ports each with 3 x 3 MWe natural gas burners

These burners are running at an estimated load factor of ~78%. This means that the demand for gas is: 7 ports x 3 burners/port x 3 MW/burner x 79%, or about 49MWth. The approximate thermal capacity of the flat glass melting furnaces is therefore: 5 furnaces x 49 MWth/furnace = 245 MWth).

From discussions with British Glass, it has been assumed that in order to attain the temperatures required for glass melting using syngas or hydrogen with the <u>current glass furnaces</u>, a proportion of natural gas will still have to be burned. This is because the lower calorific value of syngas and hydrogen with respect to natural gas would mean a greater volume of fuel gas will have to be introduced into the furnace. This would increase the mass flow of combustion products which may alter the characteristics of the process. If this increased mass flow is too large, the glass furnace may have to be changed, thus triggering wider process change. This study does not consider wider process change and so it has been assumed that current glass melting furnaces can be retained up to increased mass flows associated with 50% syngas and hydrogen combustion. In the case of melting in the <u>container glass</u> sub-sector, an amount of electricity (about 3% of energy input to the container glass melting furnace) is used. This is consumed by electrodes submerged in the molten glass bath and plays the role of inducing thermal currents within the glass melt, promoting homogeneity. It is assumed that in the new technology case this function will still be required and so this electricity consumption is retained in the new technology case.

Base Case

<u>Capex of Natural Gas Burners</u>

The base case is the current capital cost of the natural gas burners.

Capex per 3 MWth burner = £10,250 (see Table 63)

Therefore Capex per MWth is £10,250/3 = £3,417 per MWth

<u>Maintenance Cost of Natural Gas Burners</u>

The natural gas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year, and is expressed per unit of fuel consumed. Therefore, the maintenance cost is £0.015/MWh.

New Technology – Syngas - Waste

The new technology case being considered is where the site instead of using natural gas burns syngas from the gasification of waste.

For the furnaces to be fuelled by syngas, a gasifier will have to be installed on the site.

Capex of Gasifier

The demand for fuel gas is at a rate of 49 MWth. A 49 MWth gasifier can be estimated to have Capex of:

49 MWth x (£55 m/32 MWth) = £84 m (See Appendix 1 – Gasifier Cost Assumptions)

The Capex per 1 MWth is therefore £84/49 MWth = £1,714,285.

However, in order to ensure that gasifier capacity is always available to supply the syngas demand, the cost per unit capacity is increased by 30% to £2,228,572 per MWth. This represents a situation where the demand for syngas is met by a number of units of capacity and at any one time 30% of these units will be not operating because they are being cleaned and maintained. This way, with a Capex of £2,228,572 per MWth, it is assumed that he demand for syngas can always be met.

Capex for New Syngas Burners

Capex per 3 MWth syngas burner = £46,798 (see Table 63). This is £46,798/3 = £15,599/MWth.

As stated above, it is assumed that syngas can only be burned at a level up to 50%, so the Capex for Syngas burners will apply only to 50% of the thermal capacity of the furnaces, i.e. 50% x 245 MWth = 122.5 MWth.

Capex of Natural Gas Burners

As stated above, it is assumed that natural gas will have to continue to be burned at a level up to 50%, so the Capex of natural gas burners (£3,417 per MWth) will apply to 50% (122.5 MWth) of the thermal capacity of the furnace in the new technology.

Capex of Back-up Natural Gas Burners

The glass melting furnace must continue to operate if the supply of syngas is disrupted. This means that the furnace must be capable of continuing to burn natural gas at 100%. This in turn implies that the furnace must continue to have natural gas burners with the capacity to do this. The new technology scenario therefore includes Capex for these back-up burners at £3,417 per MWth applying to 50% of the thermal capacity, as natural gas burners of the other 50% are routinely used.

Maintenance of Gasifier

The operational and maintenance costs of the gasifier and syngas burners are assumed to be 4.5%[147] of Capex per year.

Expressed per unit of gas output this is £14.35/MWh.

Maintenance of New Syngas Burners

The new syngas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year

---

[147] Central point from maintenance costs quoted in E4Tech 2009, IRENA Biomass for Power Generation)

Maintenance of Natural Gas Burners

The natural gas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year.

Electricity for Operation of Gasifier

The gasifier is assumed to require electricity for its running, including syngas clean-up. This electricity consumption is over and above energy consumed in the base case and so must be included in the modelling. This additional electricity consumption is assumed to be 3% of the energy value of the syngas generated[148].

Gate Fee for Waste

In this technology waste is gasified. This waste, if not gasified, may have gone to landfill. If this is the case, then accepting the waste would represent a revenue stream to the operator of the gasifier in the form of gate fee avoided. However, there is uncertainty about whether an operator would currently get a revenue for accepting waste for gasification or would have to pay for it. Moreover, there is uncertainty about the market for waste in the future. Therefore, in order to reflect this uncertainty on the modelling three prices for waste for gasification have been assumed. These are:

Gate fee of £40/tonne of waste. Under this scenario, the operator of the gasifier receives a payment of £40/tone of waste it receives for gasification. The waste is assumed to have a CV of 13 MJ/kg. Waste is assumed to be turned into syngas with an efficiency of 78%[149]. This is equivalent to a revenue to the operator of £14.20 per MWh of syngas produced. It is further assumed that the waste from the gasification step will itself require landfilling with an associated cost. To reflect this cost, the revenue accruing to the operator is reduced by 10% and so the revenue is £12.78 per MWh of syngas generated.

Gate fee of £0/tonne waste. Under this scenario, it is assumed that operator neither pays nor receives a revenue for receiving waste for gasification.

Gate fee of -£40/tonne of waste. Under this scenario, it is assumed that the market for waste is developed and waste for gasification has a market value. Consequently the operator would have to pay £40 per tonne of waste it receives. This is equivalent to a revenue to the operator of £14.20 per MWh of syngas produced (assuming GCV of waste of 13 MJ/kg). It is further assumed that the waste from the gasification step will itself require landfilling with an associated cost. To reflect this cost, the revenue accruing to the operator is reduced by 10% and so the revenue is £12.78 per MWh of syngas generated.

CO_{2e} Factor for Syngas from Waste (DRF)

Ricardo-AEA has been supplied by Ecofys with a lifecycle emissions factor of 11.9 gCO_{2e}/MJ fuel for Refuse Derived Fuel. It is assumed that this is the waste being gasified. At a gasifier conversion rate of 78% this produces a CO_{2e} factor of syngas from waste of 0.0549 $kgCO_{2e}$/kWh.

---

[148] This figure comes from conversations with gasifier suppliers supplying gasifiers for the generation of syngas which is subsequently combusted in reciprocating engines to generate electricity. In such applications, approximately 10% of the electricity generated is used to run the plant. Since the electricity generation efficiency is about 30% this means that, effectively, electricity with an energy content of 3% of the generated gas is required.

[149] Private communication with New Earth Technologies

New Technology – Syngas – Biomass

The new technology case being considered is where the site instead of using natural gas burns syngas from the gasification of biomass.

For the furnaces to be fuelled by syngas, a gasifier will have to be installed on the site

Capex of Gasifier

The demand for fuel gas is at a rate of 49 MWth. A 49 MWth gasifier can be estimated to have Capex of:

49 MWth x (£55 m/32 MWth) = £84 m (See Appendix 1 – Gasifier Cost Assumptions)

The Capex per 1 MWth is therefore £84/49 MWth = £1,714,285.

However, in order to ensure that gasifier capacity is always available to supply the syngas demand, the cost per unit capacity is increased by 30% to £2,228,572 per MWth. This represents a situation where the demand for syngas is met by a number of units of capacity and at any one time 30% of these units will be not operating because they are being cleaned and maintained. This way, with a Capex of £2,228,572 per MWth, it is assumed that he demand for syngas can always be met.

Capex for New Syngas Burners

Capex per 3 MWth syngas burner = £46,798 (see Table 63). This is £46,798/3 = £15,599/MWth.

As stated above, it is assumed that syngas can only be burned at a level up to 50%, so the Capex for Syngas burners will apply only to 50% of the thermal capacity of the furnaces, i.e. 50% x 245 MWth = 122.5 MWth.

Capex of Natural Gas Burners

As stated above, it is assumed that natural gas will have to continue to be burned at a level up to 50%, so the Capex of natural gas burners (£3,417 per MWth) will apply to 50% (122.5 MWth) of the thermal capacity of the furnace in the new technology.

Capex of Back-up Natural Gas Burners

The glass melting furnace must continue to operate if the supply of syngas is disrupted. This means that the furnace must be capable of continuing to burn natural gas at 100%. This in turn implies that the furnace must continue to have natural gas burners with the capacity to do this. The new technology scenario therefore includes Capex for these back-up burners at £3,417 per MWth applying to 50% of the thermal capacity, as natural gas burners of the other 50% are routinely used.

Maintenance of Gasifier

The operational and maintenance costs of the gasifier and syngas burners are assumed to be 4.5%[150] of Capex per year.

Expressed per unit of gas output this is £14.35/MWh.

Maintenance of New Syngas Burners

The new syngas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year

---

[150] Central point from maintenance costs quoted in E4Tech 2009, IRENA Biomass for Power Generation)

Maintenance of Natural Gas Burners

The natural gas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year.

Electricity for Operation of Gasifier

The gasifier is assumed to require electricity for its running, including syngas clean-up. This electricity consumption is over and above energy consumed in the base case and so must be included in the modelling. This additional electricity consumption is assumed to be 3% of the energy value of the syngas generated[151].

Purchase of Wood for Gasifier

In this technology waste wood is assumed to be gasified. Waste wood is considered to have a value on the market of £6.43/MWh[152]. Expressed per MWh this is £8.24/MWh. As already stated, this is a cost.

New Technology – Syngas – Hydrogen

The new technology case being considered here is that instead of burning natural gas to melt glass in the flat glass sub-sector, hydrogen is burned instead.

It is assumed here that the hydrogen is delivered to the site as compressed hydrogen by either road or rail. The uncertainty associated with the source of hydrogen for industrial use in the future means that different scenarios for hydrogen have been constructed. These are set out in detail in Appendix 9 – Assumptions Regarding Hydrogen CO_{2e} Factors and Process.

Capex for New Hydrogen Burners

Capex per 3 MWth hydrogen burner = £169,502 (see Table 63). This is £169,502/3 = £56,500/MWth.

Capex of Natural Gas Burners

As stated above, it is assumed that natural gas will have to continue to be burned at a level up to 50%, so the Capex of natural gas burners (£3,417 per MWth) will apply to 50% (122.5 MWth) of the thermal capacity of the furnace in the new technology.

Capex of Back-up Natural Gas Burners

The glass melting furnace must continue to operate if the supply of syngas is disrupted. This means that the furnace must be capable of continuing to burn natural gas at 100%. This in turn implies that the furnace must continue to have natural gas burners with the capacity to do this. The new technology scenario therefore includes Capex for these back-up burners at £3,417 per MWth applying to 50% of the thermal capacity, as natural gas burners of the other 50% are routinely used.

---

[151] This figure comes from conversations with gasifier suppliers supplying gasifiers for the generation of syngas which is subsequently combusted in reciprocating engines to generate electricity. In such applications, approximately 10% of the electricity generated is used to run the plant. Since the electricity generation efficiency is about 30% this means that, effectively, electricity with an energy content of 3% of the generated gas is required.

[152] Waste wood GCV assumed to be 16.8 MJ/kg and a price of £30/tonne (from communications with industry)

Maintenance of New Hydrogen Burners

The hydrogen burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year, and is expressed per unit of fuel consumed. Therefore, the maintenance cost is £0.24/MWh.

Maintenance of Natural Gas Burners

The natural gas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year.

16. Appendix 4 – Iron and Steel Scenario Assumptions

Background

The blast furnace process is easily the largest consumer of fuel for the generation of direct heat. Table 19 shows that it consumes 80% of all fuel generating direct heat.

According to Table 20, the predominant fuel used in the blast furnace is coke (60.1%) followed by coal (30.6%), blast furnace gas used in the stoves to heat the blast air (7.8%) and small amounts of coke oven gas, basic oxygen steelmaking gas (BOS gas) and natural gas, which together only account for about 1.5% of the fuel input to the blast furnace.

As such, a major opportunity to decarbonise the production of hot metal via the blast furnace/BOS route is to displace the predominant fuels of coke and coal with a renewable fuel.

The fuel used in the blast furnace must perform the dual role of acting as a reductant of the iron ore and as a source of heat to turn the reduced iron into liquid metal. This means that any substitute fuel must be carbon rich.

As discussed in 4.4.1, charcoal offers a renewable alternative to the mineral derived coke and coal used in the blast furnace. However, technical challenges associated with inadequate compressive strength prevent charcoal from displacing the coke charged to large blast furnaces within the main burden. In light of this, in this study, the potential to displace coal consumed in the blast furnace as pulverised coal introduced through the tuyeres with pulverised charcoal is considered, as inadequate mechanical strength of charcoal is not an obstacle to this application.

In order to reflect industry aversion to any perceived risk associated with a complete substitution of pulverised coal by pulverised charcoal, two modelling scenarios have been run, one with all pulverised coal displaced by pulverised charcoal and one with 50% of pulverised coal substituted by pulverised charcoal.

Assumptions for the Scenario - Displacement of Pulverised Coal with Pulverised Charcoal

- 30% of the fuel sent to the blast furnace is coal in the form of pulverised coal introduced through the tuyeres.
- All or 50% of this pulverised coal could be displaced by pulverised charcoal
- The price of charcoal is £768 per tonne[153]
- The calorific value of charcoal is 8.22 MWh/tonne[154]

---

[153] Revista de Metalurgia, 49 (6) p. 458-468. Table II price for Germany considered relevant to the UK case. This price is assumed to apply to 2012.

- The price of charcoal is therefore £93.43/MWh
- For simplicity, the CO_{2e} factor for charcoal is assumed to be the same as that provided for biomass – Grade A waste wood chip, UK pathway (i.e. 0.0040 kg CO_{2e}/kWh)[155]
- Existing facilities for handling, storing processing and pulverising coal can be used for charcoal.
- Blast furnaces are assumed to be operating continuously, implying that the thermal capacity of the blast furnace is:

  Fuel consumed by blast furnaces MWh/8,760 hrs = 51,989,971 MWh/8,760 hrs = 5,934 MW.

  The use of charcoal instead of pulverised coal will lead to a 10% fall in the productivity of the blast furnace. The annual production of hot metal is assumed to be 9.9 Mt. This means that 0.99 Mt of hot metal production are assumed lost with a cost to the sector of £450/tonne[156], or £446 million.

  The carbon factor for coke is 0.3944 kgCO_{2e}/kWh[157].

  The CO_{2e} factor for blast furnace gas is set at zero for the purposes of the analysis, as the carbon from blast furnace gas originates from the coke and coal inputs to the blast furnace, which have already been counted.

---

[154] http://www.engineeringtoolbox.com/fuels-higher-calorific-values-d_169.html where the calorific value given is 29,600 kJ/kg (Visited 24/10/14)

[155] Calculated from DECC Biomass & Biogas Carbon Calculator, see: https://www.ofgem.gov.uk/publications-and-updates/uk-solid-and-gaseous-biomass-carbon-calculator/ (Visited: 24/10/14)

[156] http://www.worldsteelprices.com/. Conservatively assumed that 1 tonne of hot metal lost corresponds to 1 tonne of steel lost at a value of €500/tonne (£1 = €1.1) (Visited 24/10/14)

[157] Table 2a of DECC's 2013 Appraisal Guidance (See: https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal) (Visited 24/10/14)

17. Appendix 5 – Ceramics Scenario Assumptions

Background

As stated in the main body of the report, cost effective potential modelling is undertaken for the heavy clay sub-sector. Below are the assumptions applied to the firing process.

There are an estimated 60 sites producing heavy clay products in the UK, consuming about 2,187,588 MWh for the generation of direct heat for the firing process.

Assuming a load factor of 90%, this corresponds to a rate of fuel demand at the sub-sector level for firing of level of 2,187,588 MWh/(8760*90%) = 277 MWth.

From discussions with British Ceramics Confederation (BCC), it has been assumed that in order to attain the temperatures required for heavy clay firing using syngas or hydrogen with the current kilns, a proportion of natural gas will still have to be burned. This study does not consider wider process change, as would be the case with ceramics kiln replacement, and so it has been assumed, with the advice of BCC, that current ceramic kilns can be retained up to 50% syngas and hydrogen combustion.

BCC has also provided information on average burner capacities used in heavy clay firing kilns (80 kWth), this has allowed a tailored price per unit capacity of natural gas, syngas and hydrogen burners to be used in the analysis. From Appendix 2 – Burner Cost Assumptions the burner cost per MWth of capacity is a function of capacity and a reflection of this has been possible in the modelling for heavy clay (see below).

In the modelling of heavy clay drying (the other process examined in the ceramics sector) the temperature constraints applying to firing do not pertain. Consequently, it has been assumed that all natural gas can be substituted by syngas or hydrogen in heavy clay drying. The burner capacity information available for heavy clay firing was not available for heavy clay drying, and so a tailored price per unit capacity of natural gas, syngas and hydrogen could not be used.

Base Case

Capex of Natural Gas Burners

The base case is the current capital cost of the natural gas burners.

The average individual burner capacity used in heavy clay firing is 80 kWth, which is below the smallest capacity size in Table 63 (150 kWth). The cost per kWth is therefore set the same as for 150 kWth, which is £13.3 per kW or £13,333 per MWth.

Maintenance Cost of Natural Gas Burners

The natural gas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year, and is expressed per unit of fuel consumed. Therefore, the maintenance cost is £0.015/MWh.

New Technology – Syngas - Waste

The new technology case being considered is where the site instead of using natural gas burns syngas from the gasification of waste.

For the kilns to be fired by syngas, a gasifier will have to be installed on the site.

Capex of Gasifier

From Appendix 1 – Gasifier Cost Assumptions the Capex per 1 MWth is £1,714,285. However, in order to ensure that gasifier capacity is always available to supply the syngas demand, the cost per unit capacity is increased by 30% to £2,228,572 per MWth. This represents a situation where the demand for syngas is met by a number of units of capacity and at any one time 30% of these units will be not operating because they are being cleaned and maintained. This way, with a Capex of £2,228,572 per MWth, it is assumed that he demand for syngas can always be met.

Capex for New Syngas Burners

Capex per 80 kWth syngas burner = £106.7 (see Table 63). This is £106,664/MWth.

As stated above, it is assumed that syngas can only be burned at a level up to 50%, so the Capex for Syngas burners will apply only to 50% of the thermal capacity of the furnaces, i.e. 50% x 277 MWth = 138.5 MWth.

Capex of Natural Gas Burners

As stated above, it is assumed that natural gas will have to continue to be burned at a level up to 50%, so the Capex of natural gas burners (£13,333 per MWth) will apply to 50% (138.5 MWth) of the thermal capacity of the furnace in the new technology.

Capex of Back-up Natural Gas Burners

The heavy clay firing kiln must continue to operate if the supply of syngas is disrupted. This means that the furnace must be capable of continuing to burn natural gas at 100%. This in turn implies that the furnace must continue to have natural gas burners with the capacity to do this. The new technology scenario therefore includes Capex for these back-up burners at £13,333 per MWth applying to 50% of the thermal capacity, as natural gas burners of the other 50% are routinely used.

Maintenance of Gasifier

The operational and maintenance costs of the gasifier and syngas burners are assumed to be 4.5%[158] of Capex per year.

Maintenance of New Syngas Burners

The new syngas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year

Maintenance of Natural Gas Burners

The natural gas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year.

Electricity for Operation of Gasifier

The gasifier is assumed to require electricity for its running, including syngas clean-up. This electricity consumption is over and above energy consumed in the base case and so must be

---

[158] Central point from maintenance costs quoted in E4Tech 2009, IRENA Biomass for Power Generation)

included in the modelling. This additional electricity consumption is assumed to be 3% of the energy value of the syngas generated[159].

Gate Fee for Waste

In this technology waste is gasified. This waste, if not gasified, may have gone to landfill. If this is the case, then accepting the waste would represent a revenue stream to the operator of the gasifier in the form of gate fee avoided. However, there is uncertainty about whether an operator would currently get a revenue for accepting waste for gasification or would have to pay for it. Moreover, there is uncertainty about the market for waste in the future. Therefore, in order to reflect this uncertainty on the modelling three prices for waste for gasification have been assumed. These are:

Gate fee of £40/tonne of waste. Under this scenario, the operator of the gasifier receives a payment of £40/tone of waste it receives for gasification. The waste is assumed to have a CV of 13 MJ/kg. Waste is assumed to be turned into syngas with an efficiency of 78%[160]. This is equivalent to a revenue to the operator of £14.20 per MWh of syngas produced. It is further assumed that the waste from the gasification step will itself require landfilling with an associated cost. To reflect this cost, the revenue accruing to the operator is reduced by 10% and so the revenue is £12.78 per MWh of syngas generated.

Gate fee of £0/tonne waste. Under this scenario, it is assumed that operator neither pays nor receives a revenue for receiving waste for gasification.

Gate fee of -£40/tonne of waste. Under this scenario, it is assumed that the market for waste is developed and waste for gasification has a market value. Consequently the operator would have to pay £40 per tonne of waste it receives. With a GCV of 13 MJ/kg this is equivalent to a payment of £14.20 per MWh of syngas generated. Assuming that a gate fee must also be paid for the waste resulting from gasification and that this increases the cost by 10%, this means a cost of £15.62 per MWh of syngas supplied.

CO_{2e} Factor for Syngas from Waste (RDF)

Ricardo-AEA has been supplied by Ecofys with a lifecycle emissions factor of 11.9 gCO_{2e}/MJ fuel for Refuse Derived Fuel Fuel[161]. It is assumed that this is the waste being gasified. At a gasifier conversion rate of 78% this produces a CO_{2e} factor of syngas from waste of 0.0549 $kgCO_{2e}$/kWh.

New Technology – Syngas – Biomass

The new technology case being considered is where the site instead of using natural gas burns syngas from the gasification of biomass.

For the furnaces to be fuelled by syngas, a gasifier will have to be installed on the site

Capex of Gasifier

---

[159] This figure comes from conversations with gasifier suppliers supplying gasifiers for the generation of syngas which is subsequently combusted in reciprocating engines to generate electricity. In such applications, approximately 10% of the electricity generated is used to run the plant. Since the electricity generation efficiency is about 30% this means that, effectively, electricity with an energy content of 3% of the generated gas is required.

[160] Private communication with New Earth Technologies

[161] https://www.ofgem.gov.uk/publications-and-updates/uk-solid-and-gaseous-biomass-carbon-calculator/ (Visited: 24/10/14)

From Appendix 1 – Gasifier Cost Assumptions the Capex per 1 MWth is £1,714,285. However, in order to ensure that gasifier capacity is always available to supply the syngas demand, the cost per unit capacity is increased by 30% to £2,228,572 per MWth. This represents a situation where the demand for syngas is met by a number of units of capacity and at any one time 30% of these units will be not operating because they are being cleaned and maintained. This way, with a Capex of £2,228,572 per MWth, it is assumed that he demand for syngas can always be met.

Capex for New Syngas Burners

Capex per 80 kWth syngas burner = £106.7 (see Table 63). This is £106,664/MWth.

As stated above, it is assumed that syngas can only be burned at a level up to 50%, so the Capex for Syngas burners will apply only to 50% of the thermal capacity of the furnaces, i.e. 50% x 277 MWth = 138.5 MWth.

Capex of Natural Gas Burners

As stated above, it is assumed that natural gas will have to continue to be burned at a level up to 50%, so the Capex of natural gas burners (£13,333 per MWth) will apply to 50% (138.5 MWth) of the thermal capacity of the furnace in the new technology.

Capex of Back-up Natural Gas Burners

The heavy clay firing kiln must continue to operate if the supply of syngas is disrupted. This means that the furnace must be capable of continuing to burn natural gas at 100%. This in turn implies that the furnace must continue to have natural gas burners with the capacity to do this. The new technology scenario therefore includes Capex for these back-up burners at £13,333 per MWth applying to 50% of the thermal capacity, as natural gas burners of the other 50% are routinely used.

Maintenance of Gasifier

The operational and maintenance costs of the gasifier and syngas burners are assumed to be 4.5%[162] of Capex per year.

Maintenance of New Syngas Burners

The new syngas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year

Maintenance of Natural Gas Burners

The natural gas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year.

Electricity for Operation of Gasifier

The gasifier is assumed to require electricity for its running, including syngas clean-up. This electricity consumption is over and above energy consumed in the base case and so must be included in the modelling. This additional electricity consumption is assumed to be 3% of the energy value of the syngas generated[163].

---

[162] Central point from maintenance costs quoted in E4Tech 2009, IRENA Biomass for Power Generation)

[163] This figure comes from conversations with gasifier suppliers supplying gasifiers for the generation of syngas which is subsequently combusted in reciprocating engines to generate electricity. In such applications, approximately 10% of the electricity generated is used to run the plant. Since the electricity generation efficiency is about 30% this means that, effectively, electricity with an energy content of 3% of the generated gas is required.

Purchase of Wood for Gasifier

In this technology waste wood is assumed to be gasified. Waste wood is considered to have a value on the market of £6.43/MWh[164]. Expressed per MWh this is £8.24/MWh. As already stated, this is a cost.

New Technology – Syngas – Hydrogen

The new technology case being considered here is that instead of burning natural gas to melt glass in the flat glass sub-sector, hydrogen is burned instead.

It is assumed here that the hydrogen is delivered to the site as compressed hydrogen by either road or rail. The uncertainty associated with the source of hydrogen for industrial use in the future means that different scenarios for hydrogen have been constructed. These are set out in detail in Appendix 9 – Assumptions Regarding Hydrogen CO_{2e} Factors and Process.

Capex for New Hydrogen Burners

Capex per 80 kWth hydrogen burner = £266.7 per kWth (see Table 63). This is £266,700/MWth.

Capex of Natural Gas Burners

As stated above, it is assumed that natural gas will have to continue to be burned at a level up to 50%, so the Capex of natural gas burners (£13,300 per MWth) will apply to 50% (138.5 MWth) of the thermal capacity of the furnace in the new technology.

Capex of Back-up Natural Gas Burners

The heavy clay firing kiln must continue to operate if the supply of syngas is disrupted. This means that the furnace must be capable of continuing to burn natural gas at 100%. This in turn implies that the furnace must continue to have natural gas burners with the capacity to do this. The new technology scenario therefore includes Capex for these back-up burners at £13,333 per MWth applying to 50% of the thermal capacity, as natural gas burners of the other 50% are routinely used.

Maintenance of New Hydrogen Burners

The hydrogen burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year, and is expressed per unit of fuel consumed.

Maintenance of Natural Gas Burners

The natural gas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each

---

[164] Waste wood GCV assumed to be 16.8 MJ/kg and a price of £30/tonne (from communications with industry)

18. Appendix 6 – Cement Scenario Assumptions

Mineral Products Association (MPA) has provided sector specific data on the GCV and the CO_{2e} factor associated with the SRF consumed in the sector. These figures are used by cement sites for the purposes of reporting under EU ETS. These figures are:

- GCV = 18 MJ/kg of SRF
- CO_{2e} factor = 0.1448 $kgCO_{2e}$/kWh

and are for SRF with a composition which is about 60% biomass waste and 40% non-biomass waste.

Regarding cement sites consuming SRF, there is considerable uncertainty regarding whether the site would receive a payment for this in the form of gate fee avoided or would have to pay for the consumption of this fuel. There is also uncertainty regarding what the market for SRF will look like in the future and, therefore, at what level receipts or payments would be made. Gathering data from cement sites on the current receipts or payments made in respect of SRF is problematic in the timeframe of this study as this information is deemed very commercially sensitive.

In order to reflect this uncertainty three 'prices' for SRF have been examined in the modelling. These are:

Gate fee of £40/tonne of SRF. Under this scenario, the operator of the cement plant receives a payment of £40/tonne of SRF. As stated above, the SRF is assumed to have a GCV of 18 MJ/kg. This means a payment received of £8/MWh of SRF consumed.

Gate fee of £0/tonne of SRF. Under this scenario, the operator of the cement plant neither receives a payment nor pays for the SRF it consumes.

Gate fee of £40/tonne of SRF. Under this scenario, the operator of the cement plant pays £40/tonne of SRF. As stated above, the SRF is assumed to have a GCV of 18 MJ/kg. This means a payment made of £8/MWh of SRF consumed.

The following scenarios have been modelled.

Scenario 1a Biomass (40% waste wood chip, 60% coal)

There are assumed to be 12 sites making clinker.

From Table 33 it was shown that pure biomass (waste wood chip, MBM and sludges etc.) is used in relatively small quantities. Therefore, it is assumed that to burn biomass at 40% there would be capital costs associated with more biomass storage and transport of the fuel to the kiln. This is set at £285,000[165]per average site with a clinker capacity of 0.78 Mt/year. This gives a total Capex of £285,000/site * 12 sites = £3,420,000.

---

[165] Figure provided by MPA following consultation with members

There is an assumed Opex of the additional fuel storage and handling facility equal to 1% of the Capex incurred every year. This is a maintenance cost of £34,200 for the sector.

Scenario 1 b (40% SRF, 60% coal)

As SRF is already consumed across the sector at a rate of 16.5%, and is widely consumed, it is assumed that existing storage and handling facilities would be adequate to allow consumption at up to 40% to be possible. There is, therefore, no additional Capex or Opex associated with this scenario.

Scenario 2a (60% waste wood chip, 40% coal)

It is assumed that the Capex and Opex associated with new biomass storage and transport facilities (see Scenario 1a) are adequate to allow biomass to be burned at 60%. However, it is assumed that consumption of biomass at 60% would require more deliveries and this would require Capex for new walking floor trailers. It is estimated that about two of these would be required per site at a total cost of £100,000, or £1,200,000 for the sector.

There is an assumed Opex of the additional fuel storage and handling and walking floor trailers per facility equal to 1% of the Capex incurred every year.

Scenario 2b (60% SRF, 40% coal)

As with Scenario 2a, it is assumed that the existing storage and handling facilities for SRF are sufficient to allow SRF to be consumed at levels up to 60%, so there is no additional Capex and Opex. However, it is assumed that consumption of SRF at 60% would require more deliveries and this would require Capex for new walking floor trailers. It is estimated that about two of these would be required per site at a total cost of £100,000, or £1,200,000 for the sector.

There is an assumed Opex of the additional walking floor trailers per facility equal to 1% of the Capex incurred every year.

Scenario 3a (80% waste wood chip, 20% coal)

In this scenario, the fuel storage and handling and walking floor trailer costs applying in Scenario 2a apply. However in order to consume biomass at up to 80%, MPA inform us of the following requirements:

Pre-calciners would be need on all kilns. Pre-calciners are not present on all kilns at present and it is assumed that it is required at 4 of the 12 sites, with a Capex of £87m per site (this is the mid-point of a range of £75-100m offered by MPA. The other 8 sites are assumed to have pre-calciners.

To obtain a high enough flame temperature in the multi-channel burner in the kiln using such high overall levels of biomass would require oxygen enrichment and a new burner, with Capex of £1m at each site.

High levels of biomass combustion (as in this scenario) produce an additional quantity of water vapour in the combustion products which must be pulled through the kiln than is presently the case. This necessitates a new draught fan at a Capex of £2m per site.

All of the above Capex is assumed to have an Opex of 1% of the Capex incurred every year.

Scenario 3b(80% SRF, 20% coal)

In this scenario, the walking floor trailer costs applying in Scenario 2b apply. However, in order to consume SRF at up to 80%, MPA inform us of the following requirements:

Pre-calciners would be need on all kilns. Pre-calciners are not present on all kilns at present and it is assumed that it is required at 4 of the 12 sites, with a Capex of £87m per site (this is the mid-point of a range of £75-100m offered by MPA. The other 8 sites are assumed to have pre-calciners.

To obtain a high enough flame temperature in the multi-channel burner in the kiln using such high overall levels of biomass would require oxygen enrichment and a new burner, with Capex of £1m at each site.

High levels of biomass combustion (as in this scenario) produce an additional quantity of water vapour in the combustion products which must be pulled through the kiln than is presently the case. This necessitates a new draught fan at a Capex of £2m per site.

All of the above Capex is assumed to have an Opex of 1% of the Capex incurred every year.

19. Appendix 7 – Maltings Scenario Assumptions

Background

As stated in the main body of the report, cost effective potential modelling is undertaken for the Maltings sub-sector of the Food and Drink sector. There is only one process in this sub-sector using direct heat and this is the kilning process. Below are the assumptions applied to the kilning process.

Although there may be technical potential for the consumption of pulverised biomass in the kilns using air to air heat exchangers (because the combustion products do not come into direct contact with the product being kilned), it is not possible to undertake cost effective modelling of this potential owing to the lack of data on the cost of burners capable of burning pulverised biomass. As such, the candidate fuels being considered here are syngas-waste, syngas-biomass and hydrogen.

There are an estimated 23 kilns using air to air heat exchange with an average capacity per kiln of 12 MW. There are also an estimated 4 kilns using heat directly with an average capacity per kiln of 6 MW, summarised in Table 64.

Table 64 Type and number of kilns and average thermal capacity for the Maltings sub-sector

Number of air to air kilns	23
Average capacity of air to air kiln (MW)	12
Number of direct kilns	4
Average capacity of direct kilns (MW)	6
Fuel consumption for direct heat in kilning (MWh)	350,000
Approx. total burner capacity	(23 kiln*12 MW/kiln)+(4 kiln*6MW/kiln) = 300 MW
Implied Load Factor	(350,000 MWh/(300 MW*8760 hrs) = 13.3%

Owing to the relatively low temperature required for the maltings process, it is assumed that syngas and hydrogen can 100% substitute the incumbent fuel.

Base Case

Capex of Natural Gas Burners

Although 10% of the fuel consumed in kilning in the Maltings sector is fuel oil, the base case will assume that the Capex applies to natural gas burners, which is a reasonable assumption, given that 90% of the fuel currently burned is natural gas.

Capex per 3 MWth burner = £10,250 (see Table 63)

Therefore Capex per MWth is £10,250/3 = £3,417 per MWth

Maintenance Cost of Natural Gas Burners

The natural gas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year, and is expressed per unit of fuel consumed.

New Technology – Syngas - Waste

The new technology case being considered is where the site instead of using natural gas and fuel oil burns syngas from the gasification of waste.

For syngas to be available to burn, a gasifier will have to be installed on the site.

Capex of Gasifier

From Appendix 1 – Gasifier Cost Assumptions the Capex per 1 MWth is £1,714,285. However, in order to ensure that gasifier capacity is always available to supply the syngas demand, the cost per unit capacity is increased by 30% to £2,228,572 per MWth. This represents a situation where the demand for syngas is met by a number of units of capacity and at any one time 30% of these units will be not operating because they are being cleaned and maintained. This way, with a Capex of £2,228,572 per MWth, it is assumed that he demand for syngas can always be met.

Capex for New Syngas Burners

Capex per 3 MWth syngas burner = £15,999/MWth (see Table 63).

Capex of Back-up Natural Gas Burners

The maltings kiln must continue to operate if the supply of syngas is disrupted. This means that the furnace must be capable of continuing to burn natural gas at 100%. This in turn implies that the furnace must continue to have natural gas burners with the capacity to do this. The new technology scenario therefore includes Capex for these back-up burners at £3,417 per MWth.

Maintenance of Gasifier

The operational and maintenance costs of the gasifier and syngas burners are assumed to be 4.5%[166] of Capex per year.

Maintenance of New Syngas Burners

The new syngas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year

Electricity for Operation of Gasifier

The gasifier is assumed to require electricity for its running, including syngas clean-up. This electricity consumption is over and above energy consumed in the base case and so must be

---

[166] Central point from maintenance costs quoted in E4Tech 2009, IRENA Biomass for Power Generation)

included in the modelling. This additional electricity consumption is assumed to be 3% of the energy value of the syngas generated[167].

Gate Fee for Waste

In this technology waste is gasified. This waste, if not gasified, may have gone to landfill. If this is the case, then accepting the waste would represent a revenue stream to the operator of the gasifier in the form of gate fee avoided. However, there is uncertainty about whether an operator would currently get a revenue for accepting waste for gasification or would have to pay for it. Moreover, there is uncertainty about the market for waste in the future. Therefore, in order to reflect this uncertainty on the modelling three prices for waste for gasification have been assumed. These are:

Gate fee of £40/tonne of waste. Under this scenario, the operator of the gasifier receives a payment of £40/tone of waste it receives for gasification. The waste is assumed to have a CV of 13 MJ/kg. Waste is assumed to be turned into syngas with an efficiency of 78%[168]. This is equivalent to a revenue to the operator of £14.20 per MWh of syngas produced. It is further assumed that the waste from the gasification step will itself require landfilling with an associated cost. To reflect this cost, the revenue accruing to the operator is reduced by 10% and so the revenue is £12.78 per MWh of syngas generated.

Gate fee of £0/tonne waste. Under this scenario, it is assumed that operator neither pays nor receives a revenue for receiving waste for gasification.

Gate fee of -£40/tonne of waste. Under this scenario, it is assumed that the market for waste is developed and waste for gasification has a market value. Consequently the operator would have to pay £40 per tonne of waste it receives. With a GCV of 13 MJ/kg this is equivalent to a payment of £14.20 per MWh of syngas generated. Assuming that a gate fee must also be paid for the waste resulting from gasification and that this increases the cost by 10%, this means a cost of £15.62 per MWh of syngas supplied.

CO_{2e} Factor for Syngas from Waste (SRF)

Ricardo-AEA has been supplied by Ecofys with a lifecycle emissions factor of 11.9 gCO_{2e}/MJ fuel for Solid Recovered Fuel[169]. It is assumed that this is the waste being gasified. At a gasifier conversion rate of 78% this produces a CO_{2e} factor of syngas from waste of 0.0549 $kgCO_{2e}$/kWh.

New Technology – Syngas – Biomass

The new technology case being considered is where the site instead of using natural gas burns syngas from the gasification of biomass.

For the furnaces to be fuelled by syngas, a gasifier will have to be installed on the site

Capex of Gasifier

---

[167] This figure comes from conversations with gasifier suppliers supplying gasifiers for the generation of syngas which is subsequently combusted in reciprocating engines to generate electricity. In such applications, approximately 10% of the electricity generated is used to run the plant. Since the electricity generation efficiency is about 30% this means that, effectively, electricity with an energy content of 3% of the generated gas is required.

[168] Private communication with New Earth Technologies

[169] https://www.ofgem.gov.uk/publications-and-updates/uk-solid-and-gaseous-biomass-carbon-calculator/ (Visited 24/10/14)

From Appendix 1 – Gasifier Cost Assumptions the Capex per 1 MWth is £1,714,285. However, in order to ensure that gasifier capacity is always available to supply the syngas demand, the cost per unit capacity is increased by 30% to £2,228,572 per MWth. This represents a situation where the demand for syngas is met by a number of units of capacity and at any one time 30% of these units will be not operating because they are being cleaned and maintained. This way, with a Capex of £2,228,572 per MWth, it is assumed that he demand for syngas can always be met.

Capex for New Syngas Burners

Capex per 3 MWth syngas burner = £15,999/MWth (see Table 63).

Capex of Back-up Natural Gas Burners

The maltings kiln must continue to operate if the supply of syngas is disrupted. This means that the furnace must be capable of continuing to burn natural gas at 100%. This in turn implies that the furnace must continue to have natural gas burners with the capacity to do this. The new technology scenario therefore includes Capex for these back-up burners at £3,417 per MWth.

Maintenance of Gasifier

The operational and maintenance costs of the gasifier and syngas burners are assumed to be 4.5%[170] of Capex per year.

Maintenance of New Syngas Burners

The new syngas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year

Electricity for Operation of Gasifier

The gasifier is assumed to require electricity for its running, including syngas clean-up. This electricity consumption is over and above energy consumed in the base case and so must be included in the modelling. This additional electricity consumption is assumed to be 3% of the energy value of the syngas generated[171].

Purchase of Wood for Gasifier

In this technology waste wood is assumed to be gasified. Waste wood is considered to have a value on the market of £6.43/MWh[172]. Expressed per MWh this is £8.24/MWh. As already stated, this is a cost.

New Technology – Syngas – Hydrogen

The new technology case being considered here is that instead of burning natural gas hydrogen is burned instead.

It is assumed here that the hydrogen is delivered to the site as compressed hydrogen by either road or rail. The uncertainty associated with the source of hydrogen for industrial use in the

---

[170] Central point from maintenance costs quoted in E4Tech 2009, IRENA Biomass for Power Generation)

[171] This figure comes from conversations with gasifier suppliers supplying gasifiers for the generation of syngas which is subsequently combusted in reciprocating engines to generate electricity. In such applications, approximately 10% of the electricity generated is used to run the plant. Since the electricity generation efficiency is about 30% this means that, effectively, electricity with an energy content of 3% of the generated gas is required.

[172] Waste wood GCV assumed to be 16.8 MJ/kg and a price of £30/tonne (from communications with industry)

future means that different scenarios for hydrogen have been constructed. These are set out in detail in Appendix 9 – Assumptions Regarding Hydrogen CO_{2e} Factors and Process.

Capex for New Hydrogen Burners

Capex for 3 MWth hydrogen burner = £56,500 per MWth.

Capex of Back-up Natural Gas Burners

The maltings kiln must continue to operate if the supply of syngas is disrupted. This means that the furnace must be capable of continuing to burn natural gas at 100%. This in turn implies that the furnace must continue to have natural gas burners with the capacity to do this. The new technology scenario therefore includes Capex for these back-up burners at £3,417 per MWth.

Maintenance of New Hydrogen Burners

The hydrogen burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year, and is expressed per unit of fuel consumed.

20. Appendix 8 – Paper Scenario Assumptions

Background

As stated in the main body of the report, cost effective potential modelling is undertaken for the Tissue sub-sector.

There are an estimated 16 sites producing tissue in the UK, consuming about 1,011,000 MWh of natural gas for the generation of direct heat. This corresponds to an average per site consumption of 63,187 MWh.

The load factors for these tissue sites ranges from about 95% at the larger sites to 50% at some of the smaller, more specialist sites. From conversations with the Confederation of Paper Industries (CPI) it would be appropriate to assume an average load factor in the tissue sub-sector of 80%. This means that he rate of fuel demand at the site level is 63,187 MWh/(8760 hrs x 80%) = 9 MWth. This means that the average tissue site, wishing to burn syngas, would require a gasifier capable of producing syngas at a rate of 9 MW.

Owing to the relatively low temperature required for the drying process, it is assumed that syngas and hydrogen can 100% substitute the incumbent fuel.

Base Case

Capex of Natural Gas Burners

Capex per 3 MWth burner = £10,250 (see Table 63)

Therefore Capex per MWth is £10,250/3 = £3,417 per MWth

Maintenance Cost of Natural Gas Burners

The natural gas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year, and is expressed per unit of fuel consumed.

New Technology – Syngas - Waste

The new technology case being considered is where the site instead of using natural gas and fuel oil burns syngas from the gasification of waste.

For syngas to be available to burn, a gasifier will have to be installed on the site.

Capex of Gasifier

From Appendix 1 – Gasifier Cost Assumptions the Capex per 1 MWth is £1,714,285. However, in order to ensure that gasifier capacity is always available to supply the syngas demand, the cost per unit capacity is increased by 30% to £2,228,572 per MWth. This represents a situation where the demand for syngas is met by a number of units of capacity and at any one time 30% of these units will be not operating because they are being cleaned and maintained. This way, with a Capex of £2,228,572 per MWth, it is assumed that he demand for syngas can always be met.

Capex for New Syngas Burners

Capex per 3 MWth syngas burner = £15,999/MWth (see Table 63).

Capex of Back-up Natural Gas Burners

The tissue drying process must continue to operate if the supply of syngas is disrupted. This means that the plant must be capable of continuing to burn natural gas at 100%. This in turn implies that the plant must continue to have natural gas burners with the capacity to do this. The new technology scenario therefore includes Capex for these back-up burners at £3,417 per MWth.

Maintenance of Gasifier

The operational and maintenance costs of the gasifier and syngas burners are assumed to be 4.5%[173] of Capex per year.

Maintenance of New Syngas Burners

The new syngas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year

Electricity for Operation of Gasifier

The gasifier is assumed to require electricity for its running, including syngas clean-up. This electricity consumption is over and above energy consumed in the base case and so must be included in the modelling. This additional electricity consumption is assumed to be 3% of the energy value of the syngas generated[174].

Gate Fee for Waste

In this technology waste is gasified. This waste, if not gasified, may have gone to landfill. If this is the case, then accepting the waste would represent a revenue stream to the operator of the gasifier in the form of gate fee avoided. However, there is uncertainty about whether an operator would currently get a revenue for accepting waste for gasification or would have to pay for it. Moreover, there is uncertainty about the market for waste in the future. Therefore, in order to reflect this uncertainty on the modelling three prices for waste for gasification have been assumed. These are:

Gate fee of £40/tonne of waste. Under this scenario, the operator of the gasifier receives a payment of £40/tone of waste it receives for gasification. The waste is assumed to have a CV of 13 MJ/kg. Waste is assumed to be turned into syngas with an efficiency of 78%[175]. This is equivalent to a revenue to the operator of £14.20 per MWh of syngas produced. It is further assumed that the waste from the gasification step will itself require landfilling with an associated cost. To reflect this cost, the revenue accruing to the operator is reduced by 10% and so the revenue is £12.78 per MWh of syngas generated.

Gate fee of £0/tonne waste. Under this scenario, it is assumed that operator neither pays nor receives a revenue for receiving waste for gasification.

---

[173] Central point from maintenance costs quoted in E4Tech 2009, IRENA Biomass for Power Generation)

[174] This figure comes from conversations with gasifier suppliers supplying gasifiers for the generation of syngas which is subsequently combusted in reciprocating engines to generate electricity. In such applications, approximately 10% of the electricity generated is used to run the plant. Since the electricity generation efficiency is about 30% this means that, effectively, electricity with an energy content of 3% of the generated gas is required.

[175] Private communication with New Earth Technologies

Gate fee of -£40/tonne of waste. Under this scenario, it is assumed that the market for waste is developed and waste for gasification has a market value. Consequently the operator would have to pay £40 per tonne of waste it receives. With a GCV of 13 MJ/kg this is equivalent to a payment of £14.20 per MWh of syngas generated. Assuming that a gate fee must also be paid for the waste resulting from gasification and that this increases the cost by 10%, this means a cost of £15.62 per MWh of syngas supplied.

CO_{2e} Factor for Syngas from Waste (RDF)

Ricardo-AEA has been supplied by Ecofys with a lifecycle emissions factor of 11.9 gCO_{2e}/MJ fuel for Refuse Derived Fuel[176]. It is assumed that this is the waste being gasified. At a gasifier conversion rate of 78% this produces a CO_{2e} factor of syngas from waste of 0.0549 $kgCO_{2e}$/kWh.

New Technology – Syngas – Biomass

The new technology case being considered is where the site instead of using natural gas burns syngas from the gasification of biomass.

For the furnaces to be fuelled by syngas, a gasifier will have to be installed on the site

Capex of Gasifier

From Appendix 1 – Gasifier Cost Assumptions the Capex per 1 MWth is £1,714,285. However, in order to ensure that gasifier capacity is always available to supply the syngas demand, the cost per unit capacity is increased by 30% to £2,228,572 per MWth. This represents a situation where the demand for syngas is met by a number of units of capacity and at any one time 30% of these units will be not operating because they are being cleaned and maintained. This way, with a Capex of £2,228,572 per MWth, it is assumed that he demand for syngas can always be met.

Capex for New Syngas Burners

Capex per 3 MWth syngas burner = £15,999/MWth (see Table 63).

Capex of Back-up Natural Gas Burners

The tissue drying process must continue to operate if the supply of syngas is disrupted. This means that the plant must be capable of continuing to burn natural gas at 100%. This in turn implies that the plant must continue to have natural gas burners with the capacity to do this. The new technology scenario therefore includes Capex for these back-up burners at £3,417 per MWth.

Maintenance of Gasifier

The operational and maintenance costs of the gasifier and syngas burners are assumed to be 4.5%[177] of Capex per year.

Maintenance of New Syngas Burners

The new syngas burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year.

---

[176] https://www.ofgem.gov.uk/publications-and-updates/uk-solid-and-gaseous-biomass-carbon-calculator/ (Visited: 24/10/14)

[177] Central point from maintenance costs quoted in E4Tech 2009, IRENA Biomass for Power Generation)

Electricity for Operation of Gasifier

The gasifier is assumed to require electricity for its running, including syngas clean-up. This electricity consumption is over and above energy consumed in the base case and so must be included in the modelling. This additional electricity consumption is assumed to be 3% of the energy value of the syngas generated[178].

Purchase of Wood for Gasifier

In this technology waste wood is assumed to be gasified. Waste wood is considered to have a value on the market of £6.43/MWh[179]. Expressed per MWh this is £8.24/MWh. As already stated, this is a cost.

New Technology – Syngas – Hydrogen

The new technology case being considered here is that instead of burning natural gas hydrogen is burned instead.

It is assumed here that the hydrogen is delivered to the site as compressed hydrogen by either road or rail. The uncertainty associated with the source of hydrogen for industrial use in the future means that different scenarios for hydrogen have been constructed. These are set out in detail in Appendix 9 – Assumptions Regarding Hydrogen CO_{2e} Factors and Process.

Capex for New Hydrogen Burners

Capex for 3 MWth hydrogen burner = £56,500 per MWth.

Capex of Back-up Natural Gas Burners

The tissue drying process must continue to operate if the supply of syngas is disrupted. This means that the furnace must be capable of continuing to burn natural gas at 100%. This in turn implies that the furnace must continue to have natural gas burners with the capacity to do this. The new technology scenario therefore includes Capex for these back-up burners at £3,417 per MWth.

Maintenance of New Hydrogen Burners

The hydrogen burners also have a maintenance cost associated with them. This is assumed to be 3% of the capex for each year, and is expressed per unit of fuel consumed.

---

[178] This figure comes from conversations with gasifier suppliers supplying gasifiers for the generation of syngas which is subsequently combusted in reciprocating engines to generate electricity. In such applications, approximately 10% of the electricity generated is used to run the plant. Since the electricity generation efficiency is about 30% this means that, effectively, electricity with an energy content of 3% of the generated gas is required.

[179] Waste wood GCV assumed to be 16.8 MJ/kg and a price of £30/tonne (from communications with industry)

21. Appendix 9 – Assumptions Regarding Hydrogen CO_{2e} Factors and Process

For the purposes of the analysis, hydrogen is assumed to be made available for combustion at industrial sites via delivery either by road or rail tanker. This hydrogen may be produced at centralised installations operating either the water electrolysis process or the Steam Methane Reformation (SMR) process, with the latter using Carbon Capture and Storage (CCS) at some point in the future.

There is significant uncertainty regarding which of the processes would produce hydrogen in the future for industrial consumption and also when CCS would be applied to SMR. In order to reflect this uncertainty, three hydrogen scenarios have been run in the modelling, each with a different CO_{2e} trajectory. These are explained below.

Brown Scenario

In this scenario all hydrogen is assumed to come from SMR without CCS, and for this situation to pertain across all years of the modelling period.

The CO_{2e} intensity of hydrogen so produced is set at 0.2793 kg CO_{2e} per kWh. This factor has been determined as follows:

The CO_{2e} emissions associated with the production of hydrogen by SMR are assumed to be 11 tCO_{2e}/tonne hydrogen. This is a value suggested by European Industrial Gas Association (EIGA) in the Section 7.3.2 of the report: Methodology for the free allocation of emission allowances in the EU ETS post 2012emissions – Sector report for the chemical industry[180] . The GCV of hydrogen is assumed to be 39.39 kWh/kg[181]. The factor remains unchanged for all years of the modelling period.

Mixed Scenario

In this scenario all hydrogen is assumed to come from SMR. However, starting in 2031, CCS is assumed to apply to growing proportion of hydrogen SMR production. It is assumed that by 2050 50% of SMR hydrogen production has CCS, with the remaining 50% still coming from SMR without CCS and that the growth from 0% in 2030 to 50% in 2050 is linear.

Green Scenario

In this scenario all hydrogen is assumed to come for electrolysis of water, with the electrolysis process operating with an efficiency of 75%, i.e. each 1 kWh of electricity consumed during electrolysis produces hydrogen with an energy content of 0.75 kWh. This means that the CO_{2e} factor attached to hydrogen is determined by the CO_{2e} factor attached to electricity, which follows a trajectory prescribed by DECC.

The CO_{2e} factors attached to hydrogen under each of the scenarios is presented in Table 65.

---

[180] http://www.ecofys.com/files/files/091102_chemicals.pdf (Visited: 24/10/14)

[181] http://www.engineeringtoolbox.com/fuels-higher-calorific-values-d_169.html (Visited: 24/10/14)

Table 65 CO$_{2e}$ attached to hydrogen under BROWN, MIXED and GREEN scenarios

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Electricity kgCO$_{2e}$/kWh	0.3359	0.3272	0.3179	0.3081	0.2975	0.2862	0.2742	0.2614	0.2477	0.2330	0.2174	0.2008
BROWN (kgCO$_{2e}$/kWh H$_2$)	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793
MIXED (kgCO$_{2e}$/kWh H$_2$)	0.0938	0.0914	0.0888	0.0860	0.0831	0.0799	0.0766	0.0730	0.0692	0.0651	0.0607	0.0561
GREEN (kgCO$_{2e}$/kWh H2)	0.4478	0.4363	0.4239	0.4107	0.3967	0.3816	0.3656	0.3485	0.3302	0.3107	0.2899	0.2677

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Electricity kgCO$_{2e}$/kWh	0.1830	0.1640	0.1437	0.1220	0.0989	0.0923	0.0861	0.0803	0.0749	0.0699	0.0652	0.0608	0.0568	0.0529	0.0494
BROWN (kgCO$_{2e}$/kWh H$_2$)	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793
MIXED (kgCO$_{2e}$/kWh H$_2$)	0.0511	0.0458	0.0401	0.0341	0.0276	0.0258	0.0240	0.0224	0.0209	0.0195	0.0182	0.0170	0.0158	0.0148	0.0138
GREEN (kgCO$_{2e}$/kWh H2)	0.2439	0.2186	0.1916	0.1627	0.1319	0.1231	0.1148	0.1071	0.0999	0.0932	0.0869	0.0811	0.0757	0.0706	0.0659

	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Electricity kgCO$_{2e}$/kWh	0.0439	0.0447	0.0405	0.0341	0.0343	0.0311	0.0277	0.0274	0.0260	0.0260
BROWN (kgCO$_{2e}$/kWh H$_2$)	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793	0.2793
MIXED (kgCO$_{2e}$/kWh H$_2$)	0.0123	0.0125	0.0113	0.0095	0.0096	0.0087	0.0077	0.0076	0.0073	0.0073
GREEN (kgCO$_{2e}$/kWh H2)	0.0586	0.0596	0.0540	0.0455	0.0457	0.0414	0.0370	0.0365	0.0347	0.0347

22. Appendix 10 – Summary of Model for Determining the Cost Effective Potential for Candidate Fuel Substitution

The model has nine worksheets split into:

1	Blue worksheets with key assumptions for energy prices, carbon emissions factors for various fuels and CCL rates

There are two worksheets:

a) **'CCL'** which contains the 2014 Climate Change Levy (CCL) prices for electricity and gas. For information it is assumed that all of the industries considered (with the exception of Oil Refineries) have signed up to Climate Change Agreements (CCAs), so if they are electricity users secure a reduced rate of 10%, and all if they are gas users secure a reduced rate of 35%.

b) **'Assumptions'** which includes:
   - DECC's low, central and high predictions for carbon prices in real 2013 prices in £s/ tonne. For information we have assumed that the central price predictions are used.
   - DECC's carbon emissions factors (kg/kWh) for up to 19 different fuels. Note there are still further cells to populate as we have only populated the figures needed for glass (notably gas, syngas derived from waste, syngas derived from biomass, hydrogen, fuel oil and electricity) and coal. Some carbon emissions factors stay constant, but electricity and hydrogen factors fall over time as electricity generation becomes increasingly decarbonised. DECC does not provide hydrogen conversion factors, so these have been determined from work undertaken by Ricardo-AEA.
   - Energy prices in real 2013 p/kWh prices from DECC sources. Some prices (e.g. for fuel oil) are presented in real 2013 p/litre terms, so these have been converted to real 2013 p/kWh prices. Again, hydrogen figures are not supplied by DECC so these have been derived from a recent report by Fuelling Europe's Future.
   - A section called '**Energy prices reorganised'**, which presents all the energy prices in a consistent format to ease modelling.

2

Green worksheets which pick up the key figures in the blue assumptions sheets and include other sector specific assumptions around the capacity of current sectors, capital costs, operating costs, annual energy use (MWh) per sector, discount rates and inflation rates.

There are three worksheets:

a) Worksheet **'Industry non-time based inputs'** includes numbers for discount rates, inflation rates and draws on the CCL rates (assuming CCA discounts) from the blue worksheet 'CCL'. DECC has prescribed a 12% real post-tax discount rate to use. As different industries will finance investments with different combinations of debt (which is tax deductible) and equity there is a need to calculate figures at a pre-tax discount rate. A KPMG report[182] includes different Effective Tax Rates that are dependent on the ratio of capital costs to operating costs and the proportion of capital costs qualifying for taxable capital allowances. A mid-case rate of a 20% Effective Tax rate has been used. Combined with the Bank of England's 2% inflation target this gives a nominal pre-tax discount rate of 17%.[183]

b) Worksheet '**Industry time based inputs**' draws the data from the blue '**Assumptions**' worksheet for the prices of fuels, carbon prices and carbon emissions factors. As it is possible that there could be different inflation rates on different fuel supplies, the user has the ability to change inflation rates for each fuel, but a standard 2% inflation rate is used, in line with the Bank of England's inflation target. As DECC's real price projections are in 2013 real prices they have been increased by one year of inflation to base them in real 2014 prices. Then actual nominal prices are calculated. Once price information for other fuel sources (e.g. pet coke) have been included in the blue '**Assumptions**' worksheet, the green shaded cells that currently have #N/A will have numbers in them.

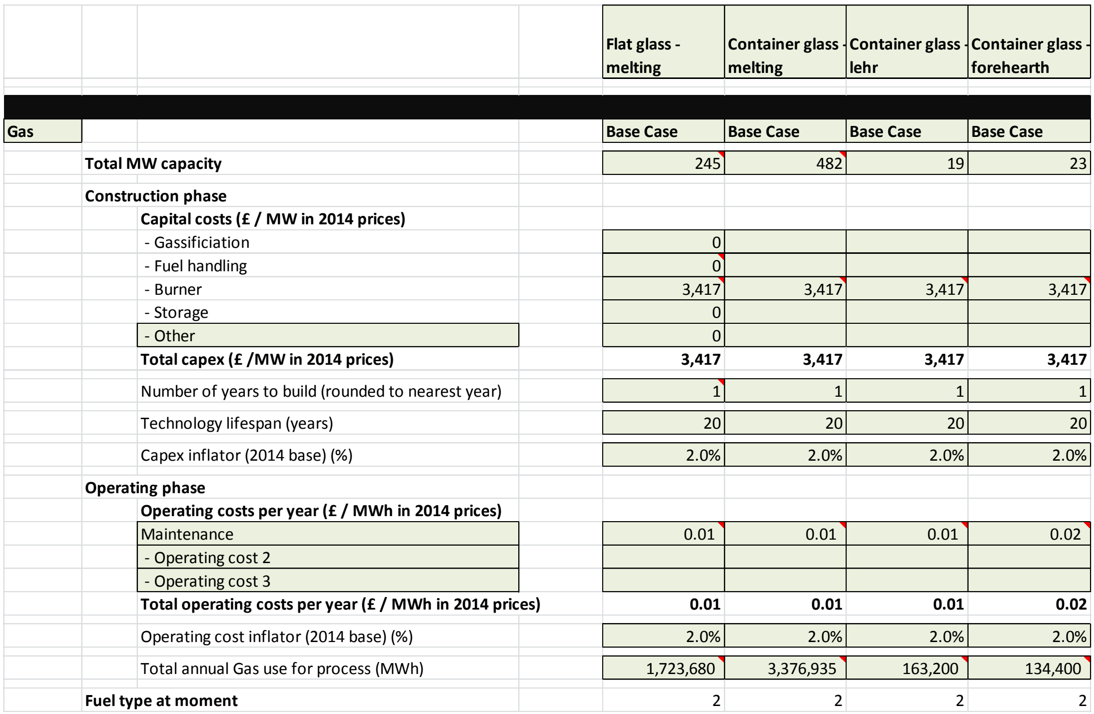
c) Worksheet '**Project non-time based inputs**' includes the key sector specific capital and operating cost figures. There are six blocks for six different possible fuels from the available drop down list of 19 fuels. There is also a drop down box for whether the technology is the base case or a new technology. The worksheet is flexible, and users can type numbers or text into the light green shaded boxes.

   The following is an illustration for information entered for gas. There are five other similar blocks for fuel oil (which is a minor base case fuel also used in container glass melting), electricity (which is a minor base case fuel also used in container glass melting, lehr and foreheath), syngas derived from waste, syngas derived from waste wood, and hydrogen.

---

[182] Electricity Market Reform: Review of effective tax rates for renewable technologies, KPMG, July 2013 - https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/225619/July_2013_DECC_EMR_ETR_Report_for_Publication_-_FINAL.pdf (Visited: 24/10/14)

[183] The 17% private discount rate is calculated as 12% real post tax rate divided by (1 – 20% effective tax rate) to give a 15% real pre-tax discount rate, or a 17% nominal pre-tax discount rate.



	Flat glass - melting	Container glass - melting	Container glass - lehr	Container glass - forehearth
Gas	Base Case	Base Case	Base Case	Base Case
Total MW capacity	245	482	19	23
Construction phase				
Capital costs (£ / MW in 2014 prices)				
- Gassificiation	0			
- Fuel handling	0			
- Burner	3,417	3,417	3,417	3,417
- Storage	0			
- Other	0			
Total capex (£ /MW in 2014 prices)	**3,417**	**3,417**	**3,417**	**3,417**
Number of years to build (rounded to nearest year)	1	1	1	1
Technology lifespan (years)	20	20	20	20
Capex inflator (2014 base) (%)	2.0%	2.0%	2.0%	2.0%
Operating phase				
Operating costs per year (£ / MWh in 2014 prices)				
Maintenance	0.01	0.01	0.01	0.02
- Operating cost 2				
- Operating cost 3				
Total operating costs per year (£ / MWh in 2014 prices)	**0.01**	**0.01**	**0.01**	**0.02**
Operating cost inflator (2014 base) (%)	2.0%	2.0%	2.0%	2.0%
Total annual Gas use for process (MWh)	1,723,680	3,376,935	163,200	134,400
Fuel type at moment	2	2	2	2

At the moment there are four columns to cover the four different glass industrial processes used, notably 'flat glass melting', 'container glass melting', 'container glass lehr' and 'container glass foreheath.'

The input cells are self-explanatory. However, two important points to note are:

- There is a need to enter the number of years the asset would take to build. At this point the user can only enter whole years, but thought is being given to allowing partial years (e.g. ¼ of a year). During the construction phase the plant is assumed to be closed down so there are no operating costs, no fuel use and therefore no emissions. Clearly operators will want to minimise the construction period to reduce this downtime. In the row '**Technology lifespan (years)**' the user defines the lifetime of the technology from the moment the asset is built. This means that if the asset takes one year to build, and the lifetime is 20 years there will then need to be a new construction cycle after 21 years (one year for the initial construction plus the 20 year lifetime). There are no decommissioning costs included but the residual value of the new construction at the end of the 30 year assessment period (when the new construction has only run for 10 years) is counted as a positive cash flow in the analysis.
- It is possible that there are a number of different fuel sources used in the current base case. This is exemplified with container glass where currently there is a mix of gas, fuel oil and electricity. The actual MW heat capacity for container glass are:

	Container glass - melting	Container glass - lehr	Container glass - forehearth
Gas	482 MW	19 MW	23 MW
Fuel oil	49 MW	0 MW	0 MW
Electricity	16 MW	8 MW	4 MW
TOTAL	**547 MW**	**27 MW**	**27 MW**

However, it is assumed that when moving to a new fuel the whole industry would use 100% of this new fuel. For example, the case of having 547 MW of syngas derived from waste used for container glass melting is shown in output worksheet '**Process 2'**.

3

Orange worksheets provide the Net Present Values (NPVs) for different fuel uses, and the total lifetime CO_{2e} emissions.

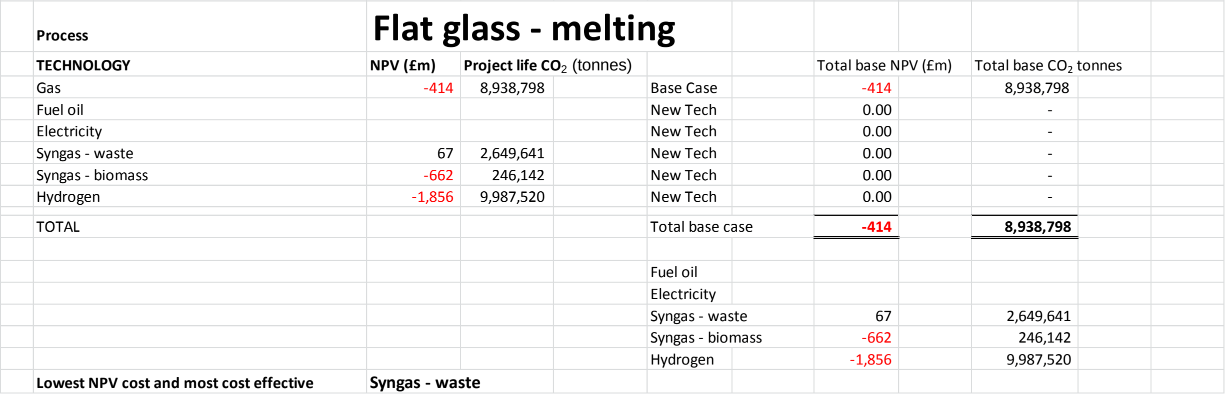
There are currently four worksheets for each of the four processes – '**Process 1**', '**Process 2**', '**Process 3'** and '**Process 4**.' Each worksheet includes the outputs for that sub-sector's process in terms of which is the most cost effective and what the lifetime CO_{2e} emissions are for that fuel. It then includes six blocks of data that include the calculations. Calculations are performed over a 30 year period from 2014 - 2043 consistent with standard UK Government policy appraisals.

Outputs

To compare a new fuel to the current base case does not provide a like for like comparison. For that reason the model calculates the NPV for the base case (which may include a mix of fuels) assuming that the existing base case fuels (normally gas, coal, electricity or fuel oil) has come to the end of its useful life and needs to be replaced either by the incumbent fuel or a new fuel. the new fuel.

The model outputs for flat glass melting are summarised in Figure 5. The NPV at 17% DR for gas is -£414 million. This means that the cost for the whole UK flat glass melting industry of buying the burners, replacing the burners after 20 years, maintaining the burners, paying for all the gas, paying all the carbon prices and CCL prices (all be it at reduced rate) at a 17% pre-tax nominal discount rate is £414 million over the 30 year period 2014-2043.

Figure 5: Summarised outputs for flat glass melting



Process	**Flat glass - melting**				
TECHNOLOGY	**NPV (£m)**	**Project life CO_2** (tonnes)		Total base NPV (£m)	Total base CO_2 tonnes
Gas	-414	8,938,798	Base Case	-414	8,938,798
Fuel oil			New Tech	0.00	-
Electricity			New Tech	0.00	-
Syngas - waste	67	2,649,641	New Tech	0.00	-
Syngas - biomass	-662	246,142	New Tech	0.00	-
Hydrogen	-1,856	9,987,520	New Tech	0.00	-
TOTAL			Total base case	**-414**	**8,938,798**
			Fuel oil		
			Electricity		
			Syngas - waste	67	2,649,641
			Syngas - biomass	-662	246,142
			Hydrogen	-1,856	9,987,520
Lowest NPV cost and most cost effective	**Syngas - waste**				

The rule for determining the most cost effective solution is to select the project with the highest positive NPV, but if no fuel gives a positive NPV the project with the smallest negative NPV cost.

Because of the gate fees achievable on flat glass melting, if syngas waste gasifiers are used, the tentative conclusion is that profit maximising flat glass melting industries should build these now as gasifiers will more than pay for themselves. If this option was not available, the second best option is to stick to the base case solution of gas. The third best option would be to introduce syngas gasifiers using waste wood, but this would cost the industry more (an NPV cost of £662 million compared to £414 million in the base case) so companies would not do this. Hydrogen is the worst case choice as hydrogen is an expensive fuel.

From a lifetime CO_{2e} perspective, as well as syngas waste gasification being the most cost effective option it also reduces the industries' 30-year CO_{2e} production by 6 million tonnes compared to using natural gas.

As an off-model calculation, for syngas gasification using waste wood, a RHI payment of about 2.2 p/ kWh would give the same NPV cost of £414 million, meaning a payment slightly higher than 2.2 p/kWh would be needed to incentivise the switch.

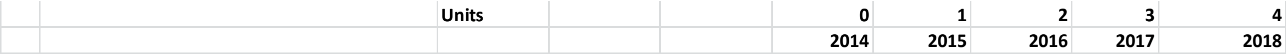
The tentative results for the three container glass processes (melting, lehr and forehearth) are not dissimilar.

Calculations

After including different inflators that are needed, and determining the asset value at different points in time, the model has a simple cash flow that includes the construction cost (and replacement construction costs), the value of the assets at the end of the 30 year policy appraisal cycle, the operating costs, fuel costs, carbon costs and CCL costs and uses all this to calculate a net pre-tax cashflow in each year. Intuitively all models should generate negative NPVs (indicating costs), but, as indicated above, in the case of waste gasification there are gate fees achievable which actually means operating revenues are greater than operating costs. In the model, if operating costs are less than operating revenues the net operating cost is shown as a positive number, meaning net operating revenue.

Figure 6 explains some of the key calculations in more detail, which are then replicated for the other five possible fuel inputs.

Figure 6: Model calculations to determine NPV



		Units			**0**	**1**	**2**	**3**	**4**
					2014	**2015**	**2016**	**2017**	**2018**

23. Appendix 11 – Summary of Results of Cost Effective Potential Analysis

Glossary of Terms Used in Summary of Results Spreadsheet

Col A Sector – The main industrial sector in which the direct heat consuming process is carried out.

Col B Sub-sector – Where applicable, the sub-sector where the direct heat consuming process is carried out.

Col C Process – The name of the direct heat consuming process

Col D Counterfactual – A description of the current way direct heat is supplied to the process

Col E New Technology – A description of how the candidate fuel could be applied to the process

Col F Annual Fuel Consumption in Counterfactual (MWh) – The annual fuel consumed for the generation of direct heat in the counterfactual

Col G Annual CO_{2e} **Emissions in Counterfactual (**tCO_{2e}**)** – The annual CO_{2e} emissions arising from the consumption of fuel for the generation of direct heat in the counterfactual

Col H Annual Fuel Saving Relative to Counterfactual (MWh) – Annual reduction in the consumption of fuel for the generation of direct heat as a result of applying the new technology

Col I Annual CO_{2e} **Savings Relative to Counterfactual (**tCO_{2e}**)** - Annual reduction in CO_{2e} emissions arising from applying the new technology. This is expressed for the first year of the saving.

Col J CO_{2e} **Saving Relative to Counterfactual- 30 Year Appraisal Period (**tCO_{2e}**)** – The total reduction in CO_{2e} over a 30 year appraisal period for the new technology, relative to the Counterfactual.

Col K Cost Relative to Counterfactual- 30 Year Appraisal Period (£m excl. CO_{2e}**) (negative value means saving)** – The costs experienced by the sector, relative to the counterfactual, over a 30 year appraisal period of the new technology. This does not include the cost of CO_{2e}.

Col L Implied Cost of Abatement (£/tCO_{2e}**)** – This is Col K/Col J

Col M Cost Relative to Counterfactual - 30 Year Appraisal Period (£ incl. CO_{2e}) (negative value means saving) – The costs experienced by the sector, relative to the counterfactual, over a 30 year appraisal period of the new technology. This does include the cost of CO_{2e}.

Col N Cost Effective Relative to Counterfactual? (Y/N) – If Col M is less than zero then the new technology has a negative NPV relative to the counterfactual, in which case the new technology is cost-effective, and vice versa.

Col O Subsidy Required to Incentivise Move from Counterfactual? (Y/N) – If Col N = N, then a subsidy would be required to encourage the uptake of the new technology

Col P Subsidy Required per unit Candidate Fuel(£/MWh) – This is the subsidy that would have to be paid against each MWh of candidate fuel consumed in order for the negative number in Col M to be turned to zero, i.e. for the costs of the new technology and the counterfactual to be the same.

24. Appendix 12 – Fuel Emission Factors and Prices

For transparency, Table 66 sets out the CO_{2e} emissions factors, prices and their associated sources and assumptions for the fuels featuring in the modelling presented above.

Table 66 CO_{2e} Factors, Prices and Data Source for the Fuel Featuring in the Modelling

Fuel	**CO_{2e} ($kgCO_{2e}$/kWh)**	CO_{2e} **Source and Comments**	**Price - 2014 (p/kWh)**	**Price Source and Comments**
Coal	0.2917	DECC IAG Toolkit (Table 2a): Industrial Steam Coal	1.1237	DECC IAG Toolkit (Table 4-8): Industrial Coal
Natural Gas	0.1841	DECC IAG Toolkit (Table 2a): Natural Gas	2.8657	DECC IAG Toolkit (Table 4-8): Industrial Gas
Syngas-waste	0.0549	Calculated from factor for Refuse Derived Fuel (0.0428 $kgCO_{2e}$/kWh) - which comes from the DECC Biomass & Biogas Carbon Calculator: https://www.ofgem.gov.uk/publications-and-updates/uk-solid-and-gaseous-biomass-carbon-calculator/ (Visited: 24/10/14) - (supplied by Ecofys) and	Depends upon gate fee assumption modelled: Gate fee = £40/tonne, Syngas-waste = - 1.278 p/kWh Gate fee = £0/tonne, Syngas – waste = 0p/kWh Gate fee = -£40/tonne, Syngas-waste = +£1.562 p/kWh	Gasifier assumed to be 78% efficient in turning the energy in the waste into the energy in the syngas-waste. Waste assumed to have a GCV of 13 MJ/kg. Additional cost assumed to fall on operator for the disposal of gasifier waste and that this increases the cost per unit of syngas used (or reduces the revenue) by 10%

Fuel	CO_{2e} ($kgCO_{2e}$/kWh)	CO_{2e} Source and Comments	Price - 2014 (p/kWh)	Price Source and Comments
		assumption that Syngas-waste generated with an efficiency of 78%		
Syngas-biomass	0.0051	Calculated from factor for Waste wood (0.0040 $kgCO_{2e}$/kWh) - which comes from the DECC Biomass & Biogas Carbon Calculator: https://www.ofgem.gov.uk/publications-and-updates/uk-solid-and-gaseous-biomass-carbon-calculator/ (Visited: 24/10/14) - (supplied by Ecofys) and assumption that Syngas-waste generated with an efficiency of 78%	0.824 p/kWh	Gasifier assumed to be 78% efficient in turning energy is waste wood into syngas-biomass. Waste wood assumed to have a GCV of 16.8 MJ/kg (Ricardo-AEA internal knowledge) and a price of £30/tonne (communications with industry).
Hydrogen	Depends upon whether "BROWN", "MIXED" or "GREEN" scenarios are being modelled. (See: Appendix 9 – Assumptions Regarding Hydrogen CO2e Factors and Process)	From discussions with DECC (See: Appendix 9 – Assumptions Regarding Hydrogen CO2e Factors and Process)	Not used – emissions increase for scenarios modelled	Not used – emissions increase for scenarios modelled
Fuel Oil	0.2688	DECC IAG Toolkit (Table 2a): Fuel Oil	5.5804	DECC IAG Toolkit (Table 4-8): Industrial Oil

Fuel	**CO_{2e} ($kgCO_{2e}$/kWh)**	CO_{2e} **Source and Comments**	**Price - 2014 (p/kWh)**	**Price Source and Comments**
Petroleum Coke	0.3479	DECC IAG Toolkit (Table 2a): Pet Coke	0.5039	https://media.argusmedia.com/~/media/Files/PDFs/Samples/Energy-Argus-Petroleum-Coke.pdf
SRF	0.1448	Provided by Mineral Products Association (MPA). This is the CO_{2e} factor associated with SRF with a GCV of 18 MJ/kg and a composition of 60% biomass/40% non-biomass waste	Depends on gate fee assumptions modelled. Gate fee = £40/tonne, SRF = -0.8 p/kWh Gate fee = £0/tonne, SRF = 0 p/kWh Gate fee = -£40/tonne, SRF = 0.8 p/kWh	Gate fee assumptions agreed with DECC
Gas Oil (Assumed for Cement)	Occurred only in Cement modelling. Factor for Fuel Oil assumed as modelling lumped Fuel Oil and Gas Oil together for modelling simplification.	Occurred only in Cement modelling. Factor for Fuel Oil assumed as modelling lumped Fuel Oil and Gas Oil together for modelling simplification.	Occurred only in Cement modelling. Price for Fuel Oil assumed as modelling lumped Fuel Oil and Gas Oil together for modelling simplification.	Occurred only in Cement modelling. Price for Fuel Oil assumed as modelling lumped Fuel Oil and Gas Oil together for modelling simplification
Gas Oil (assumed for Refineries)	0.2777	Table 1c of 2012 Guidelines to Defra / DECC's GHG Conversion Factors for Company Reporting	Not used in modelling	Not used in modelling

Fuel	CO_{2e} (kgCO_{2e}/kWh)	CO_{2e} **Source and Comments**	**Price - 2014 (p/kWh)**	**Price Source and Comments**
Refinery Gas	0.1894	Table 1c of 2012 Guidelines to Defra / DECC's GHG Conversion Factors for Company Reporting (Value for "Other Petroleum Gas" used)	Not used in modelling	Not used in modelling
Waste Solvents	Occurred only in Cement. Factor for Fuel Oil assumed	Occurred only in Cement. Factor for Fuel Oil assumed	Occurred only in Cement. Price for Fuel Oil assumed	Occurred only in Cement. Price for Fuel Oil assumed
Tyres	0.1922	Carbon Emission Factors and Calorific Values from the UK Greenhouse Gas Inventory (AEA, 2011) to Support the EU ETS	Depends on gate fee assumptions modelled. Gate fee = £40/tonne, Tyres = -0.4737 p/kWh Gate fee = £0/tonne, Tyres = 0 p/kWh Gate fee = -£40/tonne, Tyres = 0.4737 p/kWh	Assumed GCV of tyres is 30.4 GJ/tonne (see: Carbon Emission Factors and Calorific Values from the UK Greenhouse Gas Inventory (AEA, 2011) to Support the EU ETS)
Waste Oils	Occurred only in Cement. Factor for Fuel Oil assumed	Occurred only in Cement. Factor for Fuel Oil assumed	Occurred only in Cement. Price for Fuel Oil assumed	Occurred only in Cement. Price for Fuel Oil assumed
Sludges	Occurred only in Cement. Factor for Biomass assumed	Occurred only in Cement. Factor for Biomass assumed	Occurred only in Cement. Price for Biomass assumed	Occurred only in Cement. Price for Biomass assumed
Blast Furnace	0	By-product from blast furnace process. CO_{2e} assumed to be already counted in CO_{2e} for blast	0	By-product gas from blast furnace process. Assumed no commercial

Fuel	**CO_{2e} (kgCO_{2e}/kWh)**	CO_{2e} **Source and Comments**	**Price - 2014 (p/kWh)**	**Price Source and Comments**
Gas		furnace coke		value
Biomass	0.0033	From the DECC Biomass & Biogas Carbon Calculator: https://www.ofgem.gov.uk/publications-and-updates/uk-solid-and-gaseous-biomass-carbon-calculator/ (Visited: 24/10/14)	2.5503	http://www.rhincentive.co.uk/library/regulation/100201Biomass_prices.pdf (Visited: 24/10/14)
Blast Furnace Coke	0.3944	DECC IAG Toolkit (Table 2a): Coke	1.5451	Assumed to be 1.375 times the cost of industrial coal on the basis that it takes 1.375 kWh of coal to produce 1 kWh of coke (See: Table 5.2 of JRC Reference Report, BAT Reference Document for Iron and Steel Production
Charcoal	0.0033	In the absence of definitive data, assumed to be the same as biomass, from the DECC Biomass & Biogas Carbon Calculator: https://www.ofgem.gov.uk/publications-and-updates/uk-solid-and-gaseous-biomass-carbon-calculator/ (Visited: 24/10/14)	9.8595	Based on £768 per tonne (See: Revista de Metalurgia, 49 (6) p. 458-468. Table II price for Germany considered relevant to the UK case. This price is assumed to apply to 2012.) and charcoal GCV of 8.00 MWh/tonner (See: http://www.engineeringtoolbox.com/fuels-higher-calorific-values-d_169.html (Visited: 24/10/14)

Fuel	CO_{2e} (kgCO_{2e}/kWh)	CO_{2e} **Source and Comments**	**Price - 2014 (p/kWh)**	**Price Source and Comments**
				where the calorific value given is 29,600 kJ/kg)
Electricity	0.3359	DECC IAG Toolkit (Table 1): Long-run marginal – Consumption based - Industrial	9.2164	DECC IAG Toolkit (Table 4-8): Industrial Electricity

25. Appendix 13 – Detail of Biomass Scenarios Presented in Section 2.6.1

Constraints to biomass resource (from AEA for DECC 2011 paper)

The type of constraints considered included Market, Policy & Regulatory, Technical, and Infrastructural. The ratings below are subjective based on information from literature, expert opinion, technical reports and AEA experts' experience of bioenergy.

Table 67 Definition of Constraints Relating to Biomass Availability

Level of constraint	**Description**
Easy	• Constraints that act only on a portion of the supply or that could be addressed providing relatively low investment • Policy issues that could be addressed by stable UK policy or clarification of specific points of policy
Medium	• Technical or infrastructure issues requiring investment or a degree of research (similar to 'easy' but requiring higher levels of investment)
Hard	• Constraints that require considerable change in current practices (e.g. in waste management) or new technical development
Very hard	• All others, for example terrain issues that prevent development of forestry residues

Business as usual Scenario for Biomass

This scenario is based on the Hoogwijk A1 Global Economic scenario (reference below). Under this scenario, there is high technology development, the world economy grows at an average of 2% per annum, and poorer regions of the world show good development and growth, becoming more stable politically. It is assumed that this encourages development of infrastructure, and food trade is maximal.

In this scenario current trends for bio-energy production prevail. We have assumed that development of agricultural resources and infrastructure will occur regionally on much the same basis as at present (i.e. those countries already successfully developing their infrastructure, technology and political stability continue to do so, but regions where this is not happening continue to lag behind). This means that much of the bio-energy potential of less developed regions will not be available under this scenario.

In the case of woody energy crops[184], regional average yields for energy crops were derived from the results in Hoogwijk (2005), and range from 5 odt/yr (e.g. in Southern Africa) to 10

---

[184] Energy crops refer to woody biomass crops such as short rotation coppice; biofuels refers to all biofuel sources as used in the UK at present.

odt/yr (in North America) and 11 odt/yr in the Former Soviet Union. Yields are assumed to increase (as specified in Hoogwijk) at 1.6% per year in the BAU scenario, so are 37% above 2010 levels by 2030.

In the same way as for the modelling of UK energy crop resource, the maximum rate at which planting of energy crops could occur was estimated based on an assumption about the maximum rate at which the area planted each year could be expanded. This was 20% per year for developed economies, 10% per year for transition economies and 5% per year for emerging economies. Overall these planting rates constrain the area available to energy crops substantially: to 15% of the maximum area available in 2020 and 34% of the maximum available are in 2030.

In the case of 1G (first generation - wheat and sugar beet for bioethanol and oil seed rape for biofuels) biofuels feedstocks, current yields were based on data from the RFA, or FAPRI data sets, which were found to be largely consistent with values in the Kline et al (2008), OFID (2009) and ADAS (2008a) studies. Yield increases are differentiated by crop and region, but typically are about 0.9% per year in the BAU scenario. This rate of yield increase over time is kept constant for all crops except jatropha, which is currently at an early stage of development so a higher rate of increase was thought possible from 2025 onwards.

References

Hoogwijk M, Faaij A, Van den Broek R, Berndes G, Gielen D, Turkenburg W. (2003) Exploration of the ranges of the global potential of biomass for energy. Biomass Bioenergy 2003; 25(2):119–33.

Hoogwijk (2005). Potential of biomass energy out to 2100, for 4 IPCC SRES land-use scenarios. Biomass and bioenergy 29(4).

Hoogwijk M and Graus W (2008) Global potential of renewable energy sources: a literature assessment undertaken for REN 21 PECSNL072975

Reference Demand Scenario

In order to understand what proportion of the feedstock resource in other countries might be traded we also need to take demand in the country of production and other countries into account. To do this we used the ‘reference’ demand, as predicted in the IEA World Energy Outlook 2009 (IEA 2010), as a basis for our reference global bioenergy demand scenario. The demand for biofuels was cross checked against any mandates which have been set for biofuels use, and the demand updated to reflect any mandates which set legislative targets. For example, the EU biofuels demand was increased to ensure that the requirements of the Renewable Energy Directive would be met in 2020. We also reviewed whether countries had specific targets for the use of biomass in general, but while we identified some general targets for renewable energy use in some countries, and strategic intentions to increase the use of biomass, no specific quantitative targets were identified. The demand for biomass in the heat and power sector in the WEO forecast was therefore not adjusted.

26. Appendix 14 – Stakeholders Contacted

The following stakeholders were contacted during the course of this work:

- UK Steel (EEF)
- Chemical Industries Association
- Mineral Products Association
- British Glass Manufacturers’’ Association
- Confederation of Paper Industries
- Food and Drink Federation
- British Ceramic Confederation
- UK Petroleum Industry Association
- TATA Steel
- Sahaviriya Steel Industries
- Dunphy Combustion
- John Zink Hamworthy Combustion
- Comtherm
- Saacke Boiler and Process Firing Systems
- Fawley Refinery – ExxonMobil
- New Earth Advanced Thermal
- Sol Environmental Limited
- Thermal Developments Ltd.

Department of Energy & Climate Change
3 Whitehall Place
London SW1A 2AW
www.gov.uk/decc
URN 14D/394