LOW CARBON GAS LTD RESPONSE TO ‘BRIDGING THE GAP TO A NET ZERO FUTURE’ NOV 2019

“Decisions… to be made… to meet Britain’s pledge to be a net zero emitter of greenhouse gases by 2050… We will have to remove domestic heating from the gas grid”. Sir Patrick Vallance. HMG Chief Scientific Officer. 12.01.2020

UK uses more gas for industrial and power generation than domestic heat. Deploying hydrogen for industry is likely to be: more economic; much less disruptive, and require less inter-seasonal hydrogen storage, than deploying hydrogen for domestic heat. Four long-term destinations for a net-zero gas grid are currently being investigated:

1 Methane grid with interconnected industrial hydrogen ‘clusters’. No domestic hydrogen conversion. Deploy high pressure carbon negative BECCS. Gas interchangeability retained (Low Carbon Gas Ltd and Cadent Gas Ltd).
2 Hydrogen grid with domestic Biomethane and BioSNG ‘islands’. Domestic hydrogen conversion required. Gas interchangeability abandoned (H21 N E England).
3 Split gas grid, with North UK served by hydrogen and South UK served by Biomethane and BioSNG. Domestic hydrogen conversion required. Gas interchangeability abandoned (ENA).
4 Mixed methane and hydrogen grid with gas separation near end users. No domestic hydrogen conversion. Gas interchangeability retained except at end users. (National Grid Gas Transmission).

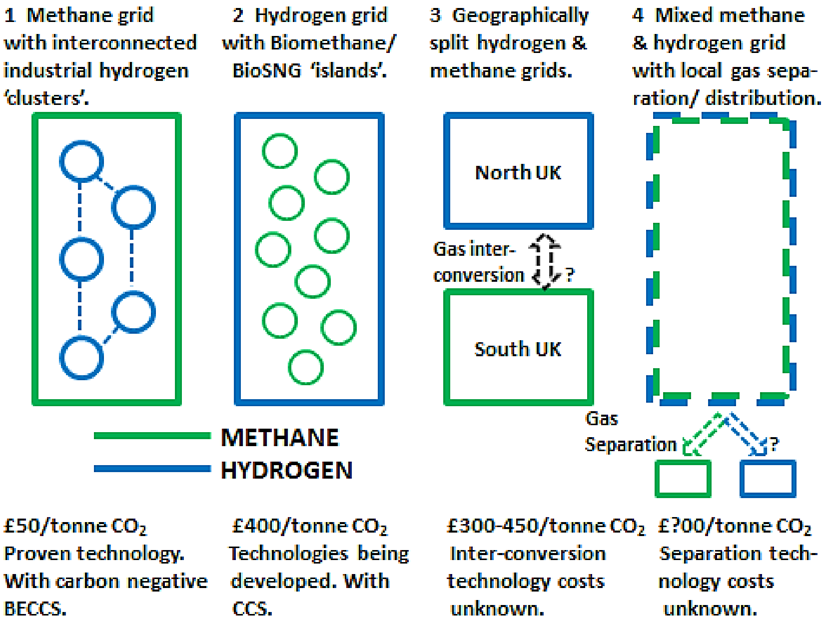
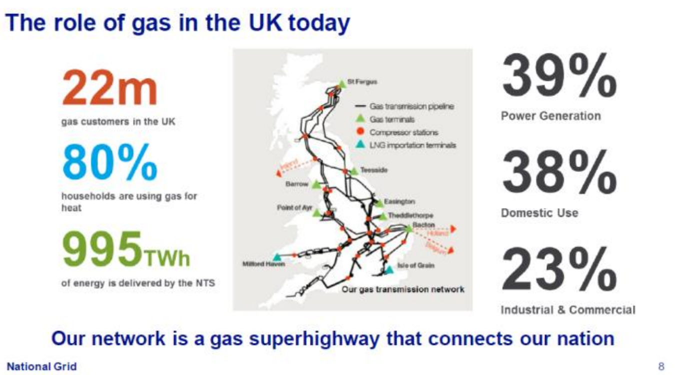
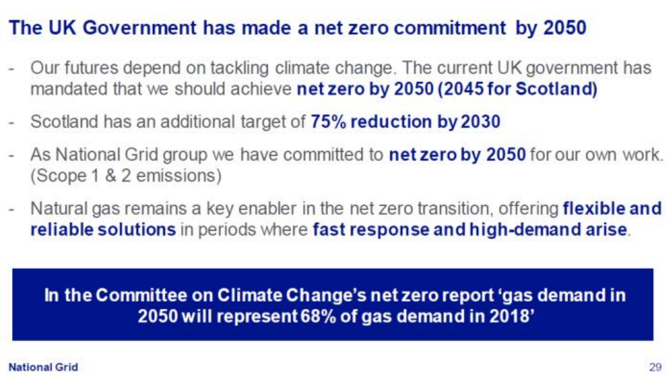


Fig 1. Comparison of the four principle gas grid decarbonisation concepts.

These 4 concepts, and their approximate marginal carbon abatement costs, are illustrated above (Fig 1). These illustrate the very high ‘whole system’ costs of abandoning the fundamental principle of gas interchangeability.





Figs 2 and 3. Current UK gas use and future decarbonisation targets.

HMG has long believed that methane cannot be decarbonised, notwithstanding the high pressure gas transmission system being UK’s premier energy ‘superhighway’ and energy storage system (Fig 2). HMG’s prediction that gas use will decrease by one third within 30 years (Fig 3) will adversely affect the long-term regulated asset value of UK’s gas infrastructure, and increase the cost of energy to gas users by driving up the cost of investment in ‘blended’ gas assets from 45 year payback @ 4.8% to 25 year payback @ 5.5%, ie 54% increase in capital recharge rate/unit energy at 68% gas demand. There is no proof that future gas use will in decrease, and much evidence to demonstrate that the bulk transfer of energy flows from the gas to the electricity grid is impractical, and the existing UK gas system can deliver net zero carbon emissions in 2050, provided that:

1 Carbon negative BECCS is deployed on high pressure methane and hydrogen synthesis to offset continued use of unabated Natural Gas for inter-seasonal energy storage, winter heat and system balancing.
2 The gas grid is treated as a single system, not as 'transmission' or 'distribution'; or 'heat', industry' or 'transport'
3 Mixed residual wastes of all kinds is used for 'drop in' gas synthesis. Synthetic gaseous hydrocarbons with BECCS will deliver <40% greater decarbonisation per unit energy than synthetic liquid hydrocarbons.

The recent report 'OFGEM decarbonisation programme actions' refers to: "electricity/electrification" 93 times; "gas/Natural Gas (NG)" 29 times, "hydrogen" 5 times, and "methane" 2 times. On p 10 OFGEM refers to "hydrogen or methane with CCS for power generation"; and on p 35 "targeted greenhouse gases… methane". This internal contradiction goes to the heart of HMG energy policy. A Martian reading this report would find no clue that methane is UK's premier energy vector; principle means of energy storage, or cleanest fuel. This is consistent with HMG policy since the 1970's, which predicted no future for methane in an all-electric, or hydrogen, economy after 2020.

OFGEM's proposed review of the Cast Iron Mains Replacement Programme and future gas transmission capacities, taken in the light of OFGEM's clear preference for massive electrification of the UK economy, has undermined investors' confidence in gas infrastructure as a long-term asset class, thus pushing up the cost of gas to consumers.

HMG has ignored the late Dr. Robert Clarke's evidence to Parliament that "ramp rates are vital" to balancing energy systems. The UK gas grid delivers 3x more average energy; 5x greater peak flow rate, and 25x greater winter morning 2 hour ramp rate than the electricity grid. Electricity supply and demand ramp rates must balance instantaneously, whereas due to gas storage capability, gas supply and demand can be out of phase.

The nearest comparison to instantaneous electricity ramp rate is the fully diversified 1:20 year peak 6 minute gas supply and ramp rates used for distribution network design. Comparative gas and electricity use at 2000 dwelling scale has been investigated by academics and ETI. The gas distribution industry is currently investigating real time gas supply rates at wide area scale, which will be published in June 2020. It is inappropriate for long-term decisions to increase the cost of gas to consumers under RIIO-2 to be made before the evidence is available to justify planning to physically transfer bulk energy supply and demand from the gas to the electricity grid. UK possesses 2000x more energy storage as gas than electricity. EU estimates gas storage is 1/10,000th the cost of electricity storage. No economically viable method exists of replacing UK gas by electricity. Gas is 1/3rd the unit price of electricity, leading to 2x more consumers being in favour of retaining gas for heat compared with other energy vectors (Fig 4).

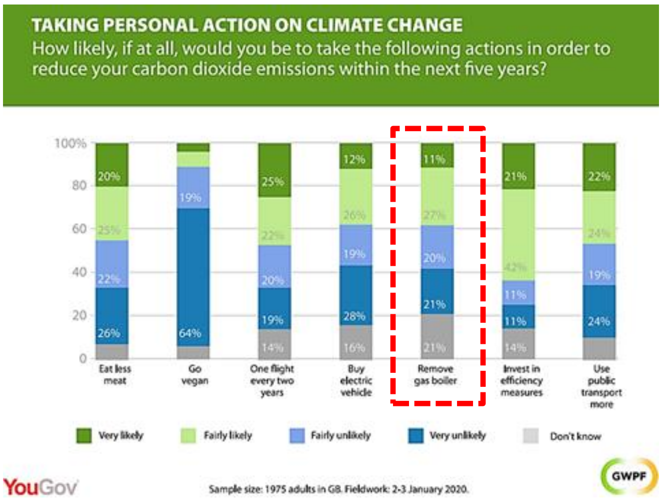


Fig 4. Recent YouGov survey: The majority of consumers want to keep their existing gas boilers.

The UK gas supply and distribution industries, with transmission as 'common carrier', have not demonstrated they can decarbonise gas and deliver the energy trilemma. Domestic hydrogen conversion at £400/tonne carbon cost will: increase fossil methane demand; reduce energy system diversity and resilience, and largely make redundant UK's premier energy 'super highway', the high pressure gas National Transmission System (NTS). ENA proposes splitting the gas system geographically into two halves: one half served by methane without CCS, and the other half served by hydrogen with CCS. Abandoning gas interchangeability will require massive re-engineering of UK's gas grid, with substantial loss of gas system and supply resilience, and consequent loss of 'whole system' energy resilience (Fig 5).

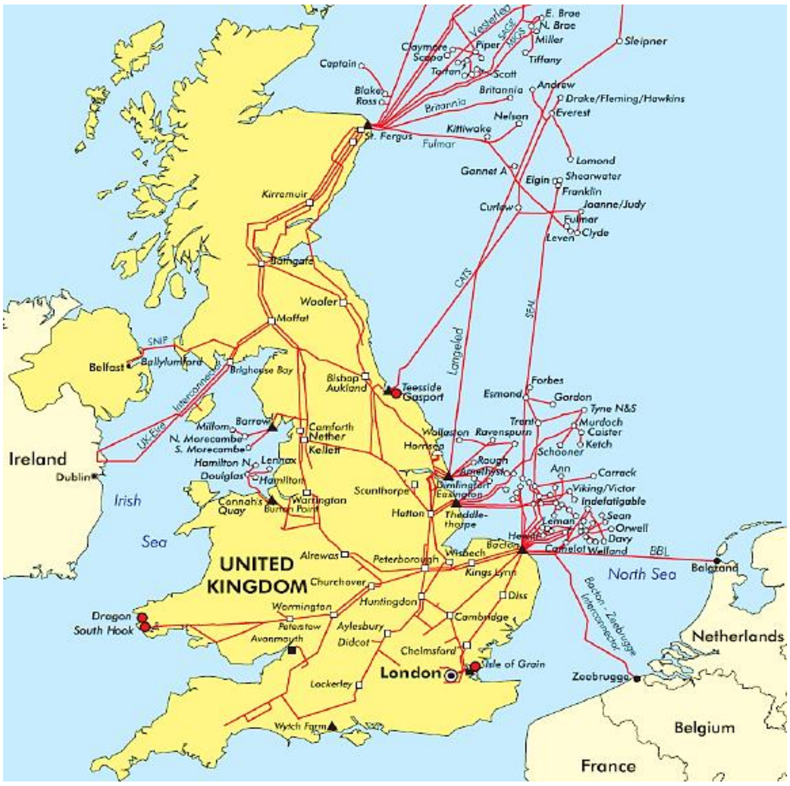


Fig 5. Fully diversified, inter-connected interchangeable high pressure gas National Transmission System: UK's 300GW energy superhighway, 125 GW/h ramp rate and 60,000 GWh energy superstore, for which no replacement currently exists.

We proposes retaining a decarbonised methane based Public access gas grid, with inter-connected local industrial hydrogen 'cluster' networks, and demonstrate it is possible to retain gas interchangeability using a combination of indigenous offshore UKCS, and onshore fossil and synthetic gas supplies to deliver: to-day's gas demand in 2050 via existing gas infrastructure and appliances; at an average 'whole system' carbon cost of ~£50/tonne, while emitting net-zero carbon emissions. This is a large claim. The technologies and fuels to decarbonise the UK gas system already exist, and were progressively proven at industrial scale between 1927 and 2008, before being mothballed This briefing note summarises the author's colleagues' lifelong experience of high pressure synthetic gas making and CO_2 capture; privileged access to the now privately owned highly detailed engineering and economic R & D records of British Gas Corporation, and the author's researches over the last 10 years into how the existing gas grid, synthetic gas making and negative emissions BECCS can be utilised most energy, cost and emissions effectively.

SCHEME DESIGN ASSUMPTIONS

1. Maintain gas' long-run 3:1 unit price advantage over electricity. Minimise the risk of consumers switching from expensive hydrogen to cheap electricity. Avoid compulsory consumer energy vector and appliance changes
2. Deliver the energy trilemma: Net zero carbon gas in 2050; retain existing NG price to consumers and industry; maintain gas resilience by producing BioSNG and biomethane onshore from indigenous fuels to replace depleting UKCS reserves. Support onshore supercritical BioCO_2 enhanced shale gas recovery with carbon negative BECCS.
3. Deliver decarbonisation at least 'whole system' cost by maximising use of low cost carbon negative BECCS to decarbonise UK's existing gas infrastructure. Gas supplies: electricity, heat, industry, chemicals and transport. Decarbonising gas at source will decarbonise all energy end use sectors.
4. There is no 'silver bullet' to decarbonising gas. We propose using all potential low carbon gas resources including biofuels; Power to Gas; CCS and carbon negative BECCS to deliver both methane and hydrogen.
5. Decarbonising the existing high pressure gas NTS, UK's premier energy 'super highway', is a National priority.
6. Deliver sufficient carbon negative 'credits' to offset use of NG to supply winter heat demand 'swing' (Fig 6). Maximise BECCS credits by deploying BECCS in BioSNG making upstream of industrial hydrogen production.

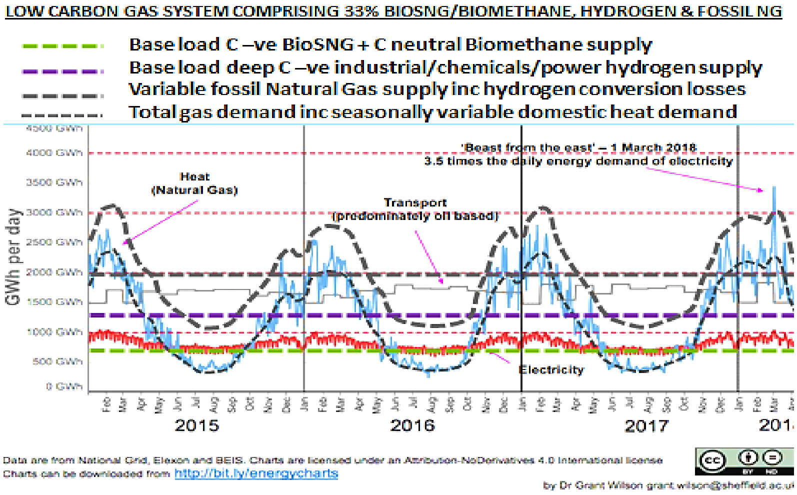


Fig 6. Annual UK gas supply comprising 33% each seasonally and diurnally variable fossil NG, and base load carbon negative BioSNG and industrial hydrogen.

7. Retain public access high pressure gas transmission and low pressure gas distribution networks as an integrated low carbon methane based energy system (Fig 7).

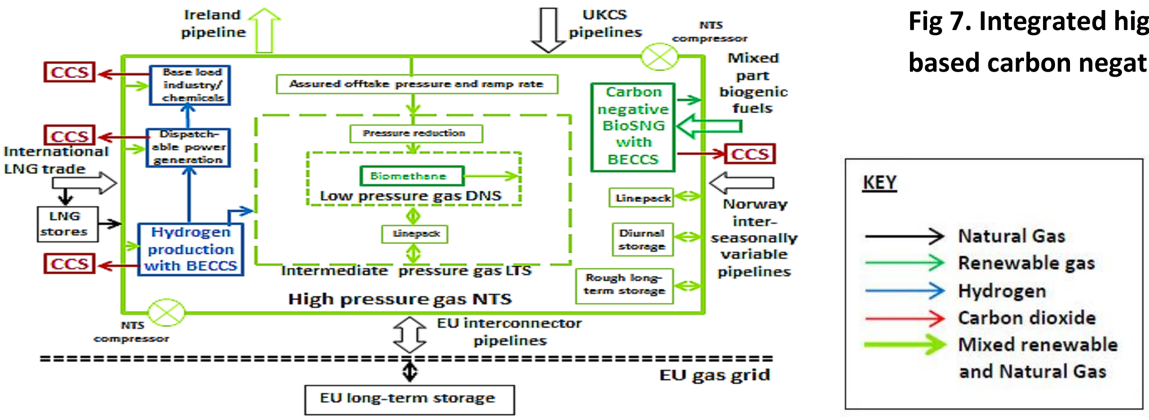


Fig 7. Integrated high pressure gas NTS based carbon negative gas system.

8. Deploy independent medium pressure hydrogen grids for industrial, chemicals, power and commercial uses. High load factor hydrogen production and line pack with excess hydrogen 'over spill' to BioSNG production. Zero inter-seasonal hydrogen storage. End use CCS where economically viable. Industrial hydrogen supplied in parallel with decarbonised methane, allowing gas end users to determine flexibly the most suitable gas mix for their needs.
9. Deliver approx. 33% each fossil NG; BioSNG and biomethane, and industrial hydrogen. Total gas demands, and split between industrial and non-industrial gas use, the same as 2014. Total NG supply exceeds 33% of total demand due to energy losses from converting methane to hydrogen.
10. Total bioenergy supply in 2050 for gas making approx. 200TWh (Fig 8).

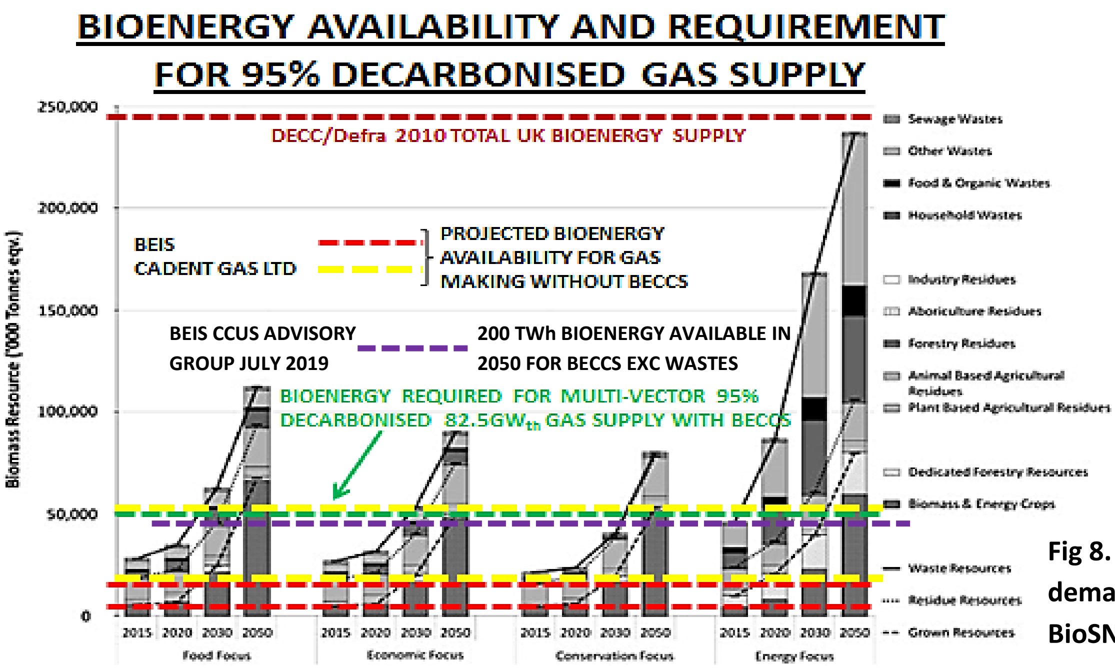


Fig 8. 2050 energy supply and demand for carbon negative BioSNG making.

11. Supplying BioSNG to the gas NTS inland mid-stream at 45 bar can stabilise NTS to DNS AOP pressure fluctuations.

AXIOMS

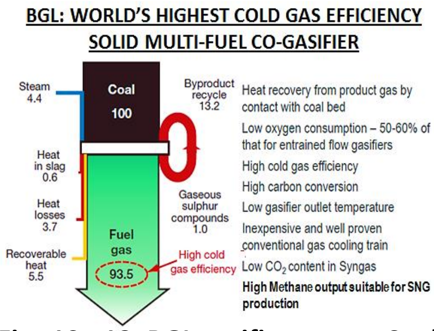
1 Interchangeability enables progressive gas decarbonisation without requiring new infrastructure (Fig 9).

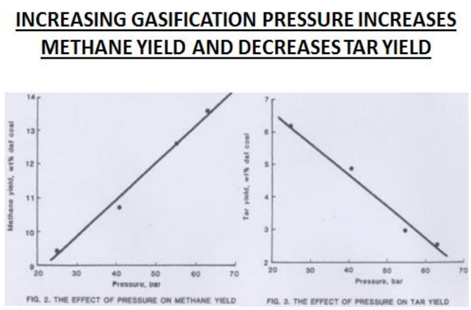
SNG 1980. British Gas Corporation ref MRS E 364 15.01.1980

It is sometimes hard to remember that a mere 15 years ago - a very short time in the history of the industry - the British gas industry was based essentially on manufactured gas, and its very long and sometimes painful experience of fuel conversion, coupled with its present research, will place it in a strong position to meet, and profit from, this new challenge. As a means of supplying the many different types of customers with the energy they need, gaseous fuels have been shown to have many advantages[1,2], such as their relatively easy storage, their transportation at low cost and with minimal environmental impact, and their convenience and efficiency in use. Among the gaseous fuels, methane - the main component of indigenous natural gas - is superior[3,4] because of its high energy content per unit volume and its ease of liquefaction for storage. It will also be the main component of substitute natural gases (SNG) made in the future, as it can be made from any fossil fuel at high efficiency. Since methane-rich manufactured gases embody all the advantages of natural gases, and as they are completely interchangeable in utilisation with the remaining natural gas supplies, so allowing use of the entire existing transmission and distribution network and appliances, the argument for their adoption as the main type of manufactured gas for public supply in the future becomes overwhelming. It seems no exaggeration to say that, ultimately, the production of substitute natural gas (SNG) will be the long term future of the British and other gas industries.

Fig 9. British Gas strategy for inter-changeable Synthetic Natural Gas [SNG] to progressively supplement and replace fossil Natural Gas, and to maximise the existing energy storage and delivery capacity of the gas grid by utilising high calorific value methane. The identical logic applies to BioSNG derived from low cost mixed biogenic and fossil fuels with carbon negative BECCS.

2 Maximising 'whole system' energy efficiency minimises resource use, emissions and costs. Proven 76% efficiency British Gas high pressure BioSNG produces 55% CO_2:45% CH_4; optimises high pressure gasification and HICOM combined shift and methanation thermo-chemical equilibria; minimises tar yield; utilises low cost physical solvent gas cleaning/separation; minimises gas compression; maximises highly efficient internal energy and mass exchange and exergy recovery from high temperature processes to generate electricity and oxygen (Figs 10 – 12). Excellent process 'fit' with high CO_2 partial pressure Timmins CCS. BioSNG is dispatchable via the gas NTS.





Figs 10 - 12. BGL gasifier energy Sankey diagram, methane and tar yields and as existing in Scotland 10 years ago.

3 The cheapest energy infrastructure, and user appliances, are those which already exist.

4 Energy system stability requires matching supply and demand ramp rates. Gas delivers 25x greater peak ramp rate than electricity. Dispatchable long-term gas storage is 1/10,000th the cost of short-term electricity storage.

5 Converting scarce biocarbon resources with BECCS to synthetic gaseous fuels (nCH_4) reduces energy emissions intensity by minimum 37% more than converting the same biocarbon to synthetic liquid fuels (nCH_2).

6 Delivering a zero net emissions gas system using BECCS, requires additional carbon negative 'credits' to offset indirect fuel processing and transport emissions, and methane emissions. We assume -15% direct negative emissions on a 'whole system' basis to offset indirect emissions.

7 Waste of all kinds is UK's most abundant and cheapest sustainable bioenergy and fossil energy resource. BECCS enables mixed part fossil/part biogenic fuels to be utilised to produce negative emissions synthetic fuels.

8 Industrial scale lump solid and liquid fuels high pressure moving bed counter-current BGL oxygen blown slagging gasifier maximises the useful range of fuel types and reactivities, and the availability of mixed fuels of all kinds.

9 AD typically uses around 25% of the available biocarbon. 50% of available biocarbon as $BioCO_2$ and solid biodigestate to be recovered for high pressure BioSNG making.

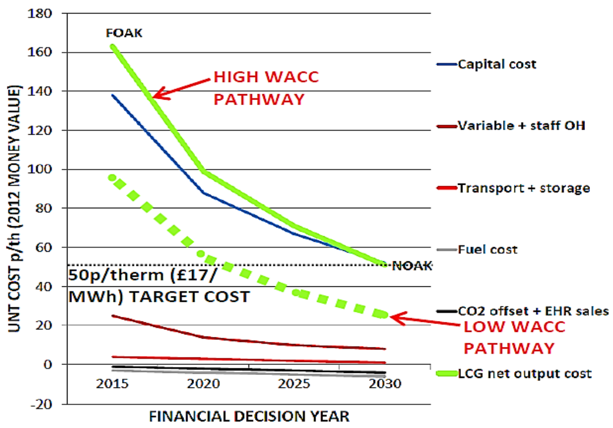
10 High pressure P2G hydrogen and oxygen can be utilised most cost effectively for high pressure BioSNG making.

11 Synthetic gas making; gas cleaning; P2G; CCS, and gas compression, storage and transmission are all most energy and cost effective at high pressure.

12 Industrial scale synthetic gas making is capital and labour intensive. Reasonable economy is achieved at minimum plant throughput of 0.5GW_{BioSNG} to 1.0 GW_{BioSNG}. BGL gasifiers available capable of <300MW_{th} throughput (Fig 13).

LOW CARBON GAS FIRST OF A KIND TO Nth OF A KIND PATHWAY ANALYSIS

FID YEAR	2015	2020	2025	2030
ENERGY INPUT (GW_{th})	0.25	0.5	0.75	1.00
FUEL INPUT (mtpa)	0.375	0.75	1.125	1.5
GASIFICATION PRESSURE (bar)	55	60	65	70
NET ENERGY EFFICIENCY (%)	75	76	76.5	77
ANNUAL LOAD FACTOR (%)	75	80	85	90
LCG PRODUCTION (million th pa)	42.0	90.9	145.8	207.2
CAPITAL RECHARGE RATE (pa)	14	12	11	10
CAPITAL COST SCALING FACTOR	1.580	1.257	1.100	1.000
CAPITAL COST (£bn/GW_{th} ENERGY OUT)	2.212	1.76	1.54	1.4
LEVELISED CAPITAL COST (p/th)	138.2	88.3	66.7	52.0
FUEL COST (p/th)	-3.0	-4.0	-5.0	-6.0
NON-FUEL VARIABLE OH (p/th)	5.0	4.0	3.5	3.0
STAFF VARIABLE OH (p/th)	20.0	10.0	6.6	5.0
CO_2 TRANSPORT & STORAGE (£/tonne)	65.0	45.0	25.0	5.0
CO_2 TRANSPORT & STORAGE (p/th)	4.0	2.8	1.5	0.3
OUTPUT COST OF LCG (p/th)	164.2	101.1	73.3	54.3
EU ETS COST OF CO_2 (£/tonne)	5.0	15.0	35.0	45.0
CO_2 SALES FOR H/C RECOVERY (£/tonne)	0.0	5.0	10.0	20.0
TOTAL CO_2 REVENUE (p/th)	-0.3	-1.5	-2.8	-4.0
NET LEVELISED LCG COST (p/th)	164	100	70	50
LCG COST AFTER CAPEX PAY OFF (p/th)	25.0	12.0	3.0	-2.0



2015 TO 2030 COST REDUCTION PATHWAY FOR CARBON NEGATIVE SYNTHETIC METHANE WITH 'HIGH' WACC REDUCING FROM 14% TO 10%, AND SECOND 'LOW' WACC PATHWAY REDUCING FROM 7% TO 5%. Fig 13.

DROP IN FUELS

Low carbon 'drop in' replacements for NG, are attractive as they minimise the 'whole system' cost of decarbonising the existing highly developed UK gas grid. A survey of synthetic fuel making processes using gasification indicates there is a 2 orders of magnitude 'gap' between small scale low pressure biofuel gasification schemes in the order of 10MW_{th} scale, and industrial scale high pressure fossil fuel gasification schemes in the order of GW_{th} scale.

Due to the capital and labour intensive nature of synthetic gas making, and the need for fuel cost savings to offset oxygen costs, it is unlikely small scale low pressure biogasification schemes will be economically viable in UK. Gas grid diversity and resilience are maximised by producing BioSNG at large scale and high pressure for use in the gas NTS, not at low pressure for use in the gas DNS. On the other hand, UK being a densely populated island with an advanced industrialised consumer society, residual waste is UK's largest and cheapest sustainable fuel stock (Fig 14).

FUEL AND EMISSIONS ANALYSIS FOR 0.750 mtpa SOLID MULTI-FUEL 468 MW_{th} INPUT BIOSNG PLANT WITH TIMMINS CCS

CarbonConnect.Decarbonising heat inquiry.ARD.24032019

Dirty' biomass, hazardous and non-hazardous wastes and biocoal high pressure slagging co-gasification to produce SNG and peak load electricity, with constant flow rate gasification plant, output load switching, Syngas storage and waste heat recovery to generation for plant use and ASU. 73.7% biogenic Car fuel input. CCS on SNG plant to meet GS(M)R. 56 bar gasification pressure. Maximise energy efficiency and minimise CCS losses. Supply low Carbon SNG to h pressure gas grid and remote 'dispatchable' NG fired CCGT's.

FUEL INPUTS (v.18) (Fuel mix by ARDay/WRG Ltd. Chemical analysis by GL Noble Denton Ltd)	Tonne pa	cv MJ/kg	£/tonne	£/GJ	£m pa	% total mass	% Carbon dry mass	% biogen-ic Carbon	Total % biogenic C	
Biomass derived biocoal	50,000	24	120	5.0	6.0	6.67%	75.00%	100%	5.00%	(<15% moisture)
Waste derived biocoal	60,000	24	48	2.0	2.88	8.00%	75.00%	60%	3.60%	(<15% moisture)
MSW	80,000	10	-25	-2.5	-2.0	10.66%	57.80%	61%	3.76%	
C and I waste	60,000	14	-25	-1.78	-1.5	8.00%	64.20%	64%	3.29%	
RDF/SRF 50/50	75,000	18	-10	-0.555	-0.075	10.00%	64.70%	54%	3.45%	(67% mass raw waste
Contaminated/woody biomass/straw	230,000	16	-10	-0.625	-2.3	30.66%	50.00%	100%	15.33%	(<25% moisture)
Tyre Derived Fuel	35,000	36.5	-25	-0.694	-0.875	4.66%	84.70%	0	0	
Hazardous bio/sewage/solvents/inks/slu	50,000	20	-100	-4.545	-5.0	6.66%	60.97%	54%	2.03%	(MBM/geno/clinical)
Processed solid biodigestate ex-AD	110,000	15.5	-5	-0.322	-0.55	14.67%	50.00%	100%	7.33%	(<25% moisture)
Total	**750,000**	**17.73**	**4.56**	**0.257**	**3.42**	**100%**	**59.44%**		**73.67%**	
Add Hazardous APC residue used as flux	10,000	0	-100	0	-1.00					(ex limestone saving
Total	**760,000**	**17.50**	**3.184**	**0.182**	**2.42**					

	AS RECEIVED DRY FUEL ANALYSIS		ULTIMATE DRY ASH FREE ANALYSIS		RAW SYNGAS TO CLEAN-UP		CLEAN SYNGAS TO HICOM		HICOM GAS WITH TIMMINS RECIRC'N		PRODUCT SNG TO GRID 60 bar		PRODUCT CO_2 TO CCS 150 bar	
Carbon	55.58%		63.06%		CH_4	16.02%	CH_4	16.32%	CH_4	15.10%	CH_4	94.70%	CH_4	0.34%
Hydrogen	5.47%		6.21%		CO_2	15.13%	CO_2	14.39%	CO_2	32.50%	CO_2	2.30%	CO_2	99.60%
Oxygen	25.07%		28.45%		H_2	20.58%	H_2	20.97%	H_2	15.90%	H_2	1.28%	H_2	N/A
Nitrogen	0.89%		1.0%		CO	45.86%	CO	46.73%	CO	35.30%	CO	0.23%	CO	N/A
Sulphur	0.60%		0.68%		N_2	0.51%	N_2	0.52%	N_2	0.40%	N_2	1.40%	N_2	N/A
Chlorine	0.52%		0.6%		H_2S COS CS_2	0.31%	H_2S COS CS_2	N/A	H_2S COS CS_2	N/A	H_2O	N/A	H_2O	0.02%
Ash	11.87%		N/A		C_xH_y	1.57%	C_xH_y	1.08%	C_xH_y	0.80%				
cv	22.939 MJ/kg		26.029MJ/kg		NH_3 HCl HCN	0.03%	NH_3 HCl HCN	N/A	NH_3 HCl HCN	N/A				

Fig 14. Fuel, gas & cost analysis used for this report. £1/GJ total fuel cost carried over into levelised cost analysis.

A small number of industrial scale gasifiers can process flexible mixes of biogenic and fossil waste based fuels with a wide range of thermochemical reactivities (carbon to hydrogen ratios). The high pressure BGL gasifier is the most suitable for BioSNG production from lump solid and liquid fuels due to its combination of high: fuel flexibility, efficiency and methane output, and low tar output, reducing the process 'work' required downstream for gas cleaning, shift and methanation. These advantages were recognised by HMG in 2001.

DEPLOYING NEGATIVE EMISSIONS BECCS ON BOTH BIOSNG AND BIOHYDROGEN PRODUCTION

We demonstrate high pressure carbon negative BioSNG production using existing proven BG technologies (Fig 15)

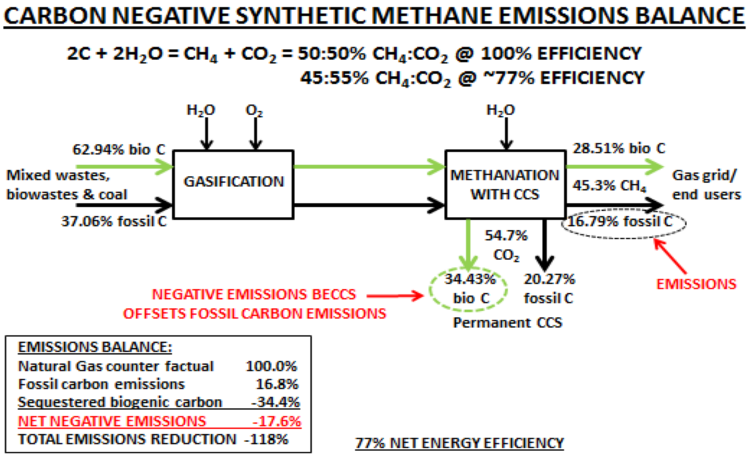


Fig 15. Carbon balance for high pressure carbon negative BioSNG with BECCS.

We propose injecting BioSNG with negative emissions BECCS into the high pressure gas NTS UPSTREAM of industrial hydrogen production. The mixed part biogenic gas used for hydrogen production with CCS will enable 'Business as Usual' industrial hydrogen production to benefit from negative emissions BECCS at no additional cost (Fig 16). This 'doubling' of negative emissions credits is vital to offsetting the continued use of fossil NG to supply inter-seasonal heat demand 'swing' without additional large scale hydrogen production, compression and storage infrastructure.

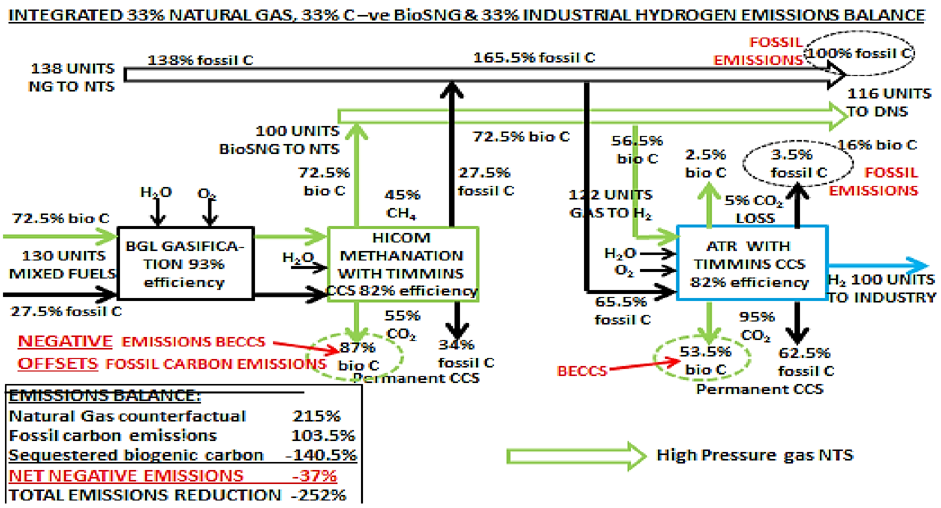


Fig 16. Carbon mass balance for a net negative emissions gas system delivering 100 units by energy each of fossil NG, carbon negative BioSNG and industrial hydrogen into the UK gas grid.

COMPARATIVE COSTS AND DEPLOYABILITY OF VARIOUS LOW CARBON GASES

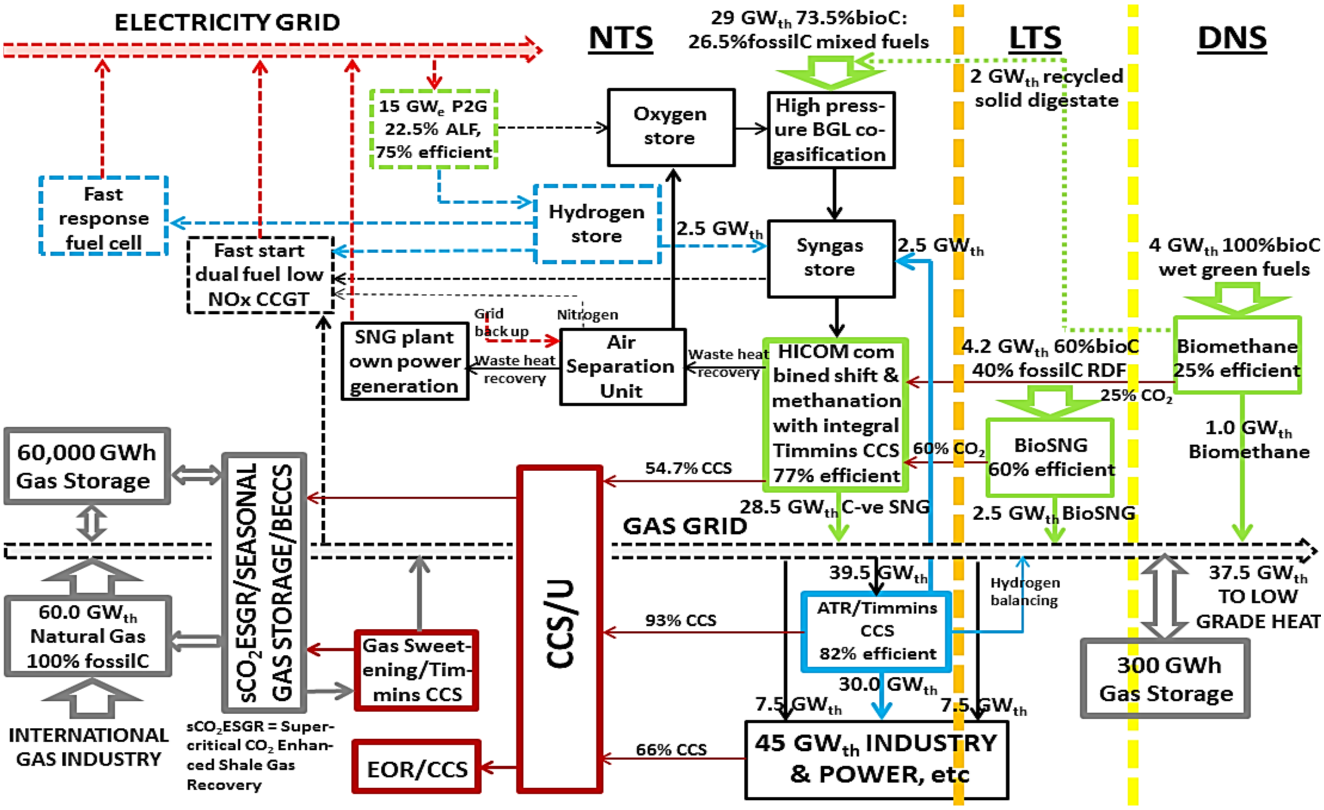
Our technology choices are informed by the comparative cost and deployability of the various low carbon gas schemes currently being proposed (Fig 17). We utilise a combination of ex-BG high pressure BioSNG making, and Cadent's NW England industrial hydrogen cluster scheme, both with fully integrated carbon negative BECCS.

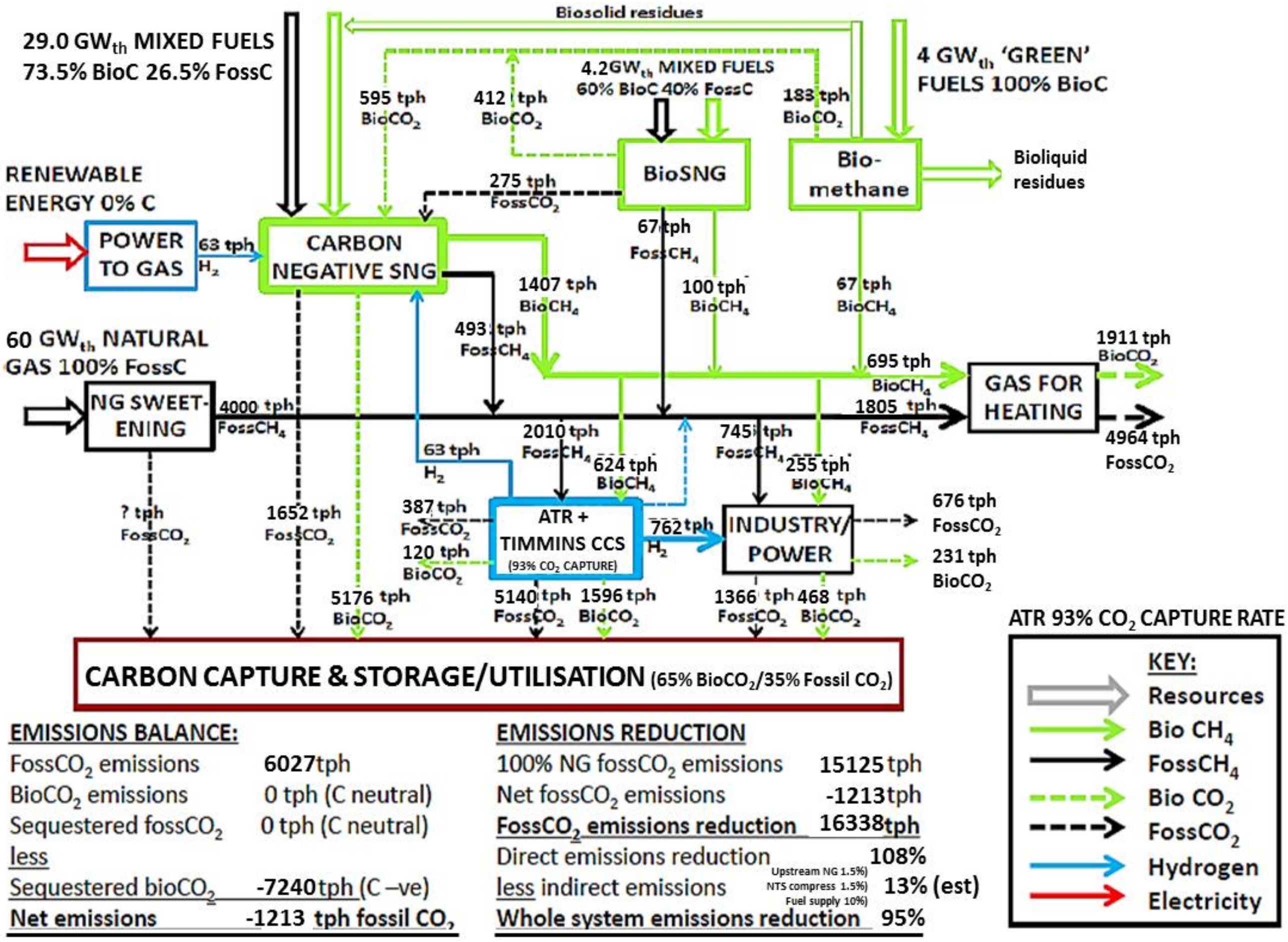
Gas type	AD to biomethane	Carbon negative SNG	BioSNG city conversion	Industrial hydrogen	Industrial hydrogen	Industrial hydrogen	Domestic hydrogen	H21+ N E England
Data source	Sustainable Gas Inst.	British Gas/Timmins	Cadent Gas Ltd	ATR Cadent/Timmins	ATR Cadent Gas Ltd	SMR Cadent Gas Ltd	SMR NGN H21	ATR NGN
Delivery pressure	1 bar	45 bar	7 bar	45 bar	45 bar	17 bar	7 bar	80 bar
Gas grid tier	DNS	NTS/LDZ interfaces	LTS	Industrial pipeline	Industrial pipeline	Industrial pipeline	DNS	HTS
Fuel type	Digestible waste/crop	Mixed waste fuels	RDF/biomass (15GJ/t)	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Fossil carbon in fuel	0%	37.5%	40%	100%	100%	100%	100%	100%
Biogenic carbon in fuel	100%	62.5%	60%	0%	0%	0%	0%	0%
CCS or BECCS enabled	n/a	BECCS	No information avail'e	CCS	CCS	CCS	CCS	CCS
Base technology	Anaerobic digestion	BGL slagging gasifier	FBR dry ash gasifier	ATR	ATR	SMR	SMR	ATR
Tar conversion technology	n/a	Recycle to gasifier	Plasma reactor	n/a	n/a	n/a	n/a	n/a
Fuel conversion pressure	1 bar	56 bar	~10 bar	50 bar	50 bar	20 bar	20 bar	80 bar
Gas synthesis technology	AD	HICOM	Shift + methanation	Shift	Shift	Shift	Shift	shift
Oxygen production technology	n/a	Heat recovery turbine	Air Liquide imported	Heat recovery turbine	Heat recovery turbine	n/a	n/a	Hydrogen CCGT
CCS technology	Water /membrane	Selexol + Timmins CCS	Not stated	Selexol + Timmins CCS	PSA	PSA	PSA	PSA
Fuel cost	n/a	£1.0/GJ	£0/GJ net (Edinburgh)	£5.0/GJ (£18/MWh)	£5.0/GJ (£18/MWh)	£5.0/GJ (£18/MWh)	£5.0/GJ (£18/MWh)	£5.0/GJ (£18/MWh)
Plant input (CAPEX/thermal input)	n/a	1.0GW (£1.1bn/GW$_{th}$ IN)	0.2GW (£1.1bn/GW$_{th}$ IN	1.1GW (£0.5bn/GW$_{th}$ IN)	1.1GW (£0.5bn/GW$_{th}$ IN)	1.0GW (£0.3bn/GW$_{th}$ IN)	1.5GW (£0.3bn/GW$_{th}$ IN)	16 GW (£0.5bn/GW$_{th}$ IN)
Levelised cost of gas	£59/MWh	£18/MWh	£36.6/MWh	£37.8/MWh	£42.8/MWh	£36/MWh	£68/MWh	£66/MWh
CO2 abatement cost	£224/tonne CO2	£2/tonne CO2	£169/tonne CO2	£103/tonne CO2	£114/tonne CO2	£90/tonne CO2	£400/tonne CO2	£393/tonne CO2
Upstream fugitive CH4 emissions	Reduced	Some reduction	Some reduction	Slight Increase	Increase	Increase	Increase	Increase
Downstream fug've CH4 emissions	Some reduction	No change	No change	No change	No change	No change	Large reduction	Large reduction
Security of supply	Slight Increase	Increase	Increase	Slight decrease	Slight decrease	Slight decrease	Decrease	Decrease
Gas interchangeability	Retained	Retained	Retained	Retained	Retained	Retained	Destroyed	Destroyed
System diversity/resilience	Increase	Increase	Increase	Reduced	Reduced	Reduced	Decrease	Decrease
Emissions reduction	-100%	-118%	-60%	-78%	-80%	-70%	-60%	-95%
Decarbonise heat	Yes	Yes	Yes	Minor	Minor	Minor	Yes	Yes
Decarbonise industry	No	Yes	Minor	Yes	Yes	Yes	No	Yes
Decarbonise power	No	Yes	No	Possibly	Possibly	Possibly	No	Yes
End user disruption	None	None	None	Minor	Minor	Minor	Major	Major
Supports power/ind'ry BECCS	No	Yes	No	No	No	No	No	No
Cost: NG price ratio	**x 3.3**	**x 1**	**x 2**	**x 2.1**	**x 2.4**	**x 2**	**x 3.75**	**x 3.66**

1 Infrastructure CAPEX. 45 year payback @ 4.25% pa Weighted Aggregate Cost of Capital inc 17% tax on interest only.
2 End use equipment & appliance conversion CAPEX. 15 year payback @ 6% WACC inc 17% tax on interest only. Also inc local DNS, meter, internal pipework and non-boiler appliance conversion.
3 Costs include e.o. gas compression, storage, transmission, distribution & dispatch compared with Natural Gas. Costs exc gas DNO OH & P, policy costs and VAT
4 £18/MWh = 52.7 p/therm inc wholesale price + NTS compression, storage & transmission costs. Exc DNO costs.

Fig 17. Comparative levelised costs and deployability of low carbon gases.

ENERGY AND CARBON BALANCES FOR A NET-ZERO EMISSIONS GAS SYSTEM AT 2014 GAS DEMAND





Figs 18 & 19. Annual energy and hourly carbon flows in a net-zero emissions gas system with carbon negative BECCS based on 2014 gas demand; 200 TWh bioenergy availability in 2050; inter-connected industrial hydrogen 'clusters', and gas interchangeability retained in the Public access gas grid.

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The technologies, or Intellectual Property, on which this report is based are owned by:

- DNV GL (BioSNG process design and integration with BECCS)
- Johnson Mathey plc (CRG LH catalyst)
- Davy Process Technology Ltd. (HICOM combined shift and methanation)
- Envirotherm GmbH (BGL gasification)
- Zemag GmbH (BGL gasification and fuel preparation)
- Linde Engineering, Air Liquide Engineering and Construction (Rectisol pre wash)
- UOP, Dow Chemicals (Selexol CO_2 separation)
- University of Cambridge, Chemical Engineering Dept. (Timmins CCS integration)
- Timmins CCS Ltd. (Timmins CCS IP)