Question No.	Proforma section	Criteria	Topic	Question	Date question asked	Date response required	Date received	Follow up to Question #	Confidential (y/n)
1	3.3.1	(a.iii)		It appears that the financial and carbon assessments use baselines that differ (maximising the apparent benefit of each aspect).[1] In order to provide greater clarity could the BAU, Heat Pump and H2 deployment scenarios be shown on a consistent basis?	23 August 2016	25 August 2016	02 September 2016		
2	3.3.1	(a.iii)		The fall in the levelised cost of hydrogen is a critical driver of the benefit estimate as shown in Table B4. In particular Bio-SNG which is itself in infancy. Can it be clarified how the risks associated with this source of hydrogen have been accounted for in the assessment of benefits.	23 August 2016	25 August 2016	03 September 2016		
3	3.3.1	(a.iii)		Can it be clarified how net benefits have been derived? In particular, what assumptions are made about additional R&D costs, what system wide costs would be incurred (eg for full H2 deployment -Dodds and Demoullin estimated conversion costs of £500 per household). Could the levelised costs be used to show analogous figures.	23 August 2016	25 August 2016	04 September 2016		
4	3.3.1	(a.iii)		Cost/carbon savings are based on 10% and 20% hydrogen blends- is there a risk that 10% may not be achievable once appliance testing etc. is conducted? “avoidance of network reinforcement otherwise required” is included in cost savings. Should it not be acknowledge that network reinforcement may be needed for reasons other than heat pump deployment i.e. electrification of vehicles?	23 August 2016	25 August 2016	05 September 2016		
5	2.3.3 (p11)	General		Does the ‘accredited by Ofgem’ reference under composition measurement and CV refer to what you are looking for a view from Ofgem on in section 7 of your submission?	25 August 2016	31 August 2016	06 September 2016		
6	Section 7	General		While we may have a view on the use of declared vs determined CV, does Ofgem have a formal role to approve the choice taken by NGGD? Broadly, what does the process for this look like and what are the timings be?	25 August 2016	31 August 2016	07 September 2016		
7	General	g		Please can you provide more information on what are the main the issues that need to be addressed for hydrogen to safely blended and used on the distribution network? This should be in the form of a chart/checklist including evidence required by HSE. If there are differences if the NTS is used please highlight those too.	09 September 2016	15 September 2016	30-Sep (Verbally), 04-Oct (Written)		
8	Appendix J	b		The cost of buying and installing an electrolyser onsite makes up a large sum of the cost of the project. (i) Why does hydrogen need to be produced by an electrolyser onsite rather than shipped in? (ii) Could the electrolyser be rented rather than bought? Please could you provide the costs of renting, if that is possible, compared to buying the electrolyser. Alternatively can it be purchased second hand? Is possible, please provide the cost of a second hand electrolyser and it's expected lifetime. (iii) Can you provide costings **and** risk assessment of having hydrogen brought and used from a safe place on the campus, compared to procuring and using an electrolyser onsite.	09 September 2016	15 September 2016	30-Sep (Verbally), 04-Oct (Written)		
9	8.2	g		(i) Please can you provide a high level customer engagement plan that will be used for customers onsite and the learning taking from Oban? (ii) Please can you include as an explicit project deliverable, the consolidation of work and learning on customer engagement for future trails of hydrogen on the public network?	09 September 2016	15 September 2016	30-Sep (Verbally), 04-Oct (Written)		
10	Appendix C (C.2.3)	b		Part of the project plan identifies that a 6” steel pipe must be inspected. (i) Why does this pipe need to be inspected? Would the inspection be needed if the project doesn’t go ahead? (ii) What is the mitigation if repairs are needed to the pipe? Are these costs included in the project cost? Given its depreciated cost vs new asset life should Keele make a contribution if it is replaced.	09 September 2016	15 September 2016	30-Sep (Verbally), 04-Oct (Written)		
11	General	a		Please can you provide more detail on: (i) The business case for biohydrogen as source (ii) The long-term cost of the production of biohydrogen compared to the cost of natural gas, given learnings over the last year and also allowing for different scenarios for gate fees.	09 September 2016	15 September 2016	30-Sep (Verbally), 04-Oct (Written)		

Gas Network Innovation Competition Full Submission

Supplementary Answer Form

Project: HyDeploy

Tick if this answer has been provided verbally: ☐

Project code	**NGGDGN03/1**	**Question Number**	**1**
Question date	**230816 (delivered 310816)**	**Answer date**	**020916**
Submission section question relates to	**3.3.1**		
Topic	**Benefits**		
Question	**It appears that the financial and carbon assessments use baselines that differ (maximising the apparent benefit of each aspect).[1] In order to provide greater clarity could the BAU, Heat Pump and H2 deployment scenarios be shown on a consistent basis?**		
Notes on question	[1] Financial benefits: In section 3.3 a 'baseline' is used which measures the difference between levelised costs of air source heat pumps and business as usual –so an incremental difference in costs is used. From the analytical view this 'hides' the financial performance relative to BAU. The benefit of the project then emerges from a sharply falling H2 cost (but this is dependent on other technology). Carbon benefits: are measured in relation to BAU so are on a different baseline relative to financial benefits. See also eg page 59.		

Answer	The UK has national commitments to carbon savings, and to do so requires de-carbonisation of heat. Both heat pumps and hydrogen deliver substantial carbon savings relative to business as usual. However, hydrogen not only does so with less disruption to consumers, but also at lower cost. The overarching approach taken was to evaluate the costs and carbon emissions for the scenarios, and therefore to present the benefits. Appendix B of the submission, particulary p59, provides: • The absolute costs of decarbonisation via heat pumps as well as the additional costs compared with fossil gas boilers • The absolute carbon intensity of heat delivered by hydrogen as well as the carbon savings relative to fossil gas boilers However, it is recognised that we didn't show the absolute or relative carbon intensity of heat delivered by heat pumps. This was calculated, but not provided and is required for completeness. The table below shows all the data on a consistent basis as absolute values as well as relevant comparisons This shows that both hydrogen and heat pump deliver very similar levels of carbon savings, but the hydrogen route is substantially lower cost compared with heat pumps. Not only is it therefore a much less disruptive solution for the gas customer compared with heat pumps, it does so at lower cost; this is the saving shown in the submission.
Attachments	See Table below

Absolute Values for GB at 20% (Method 1)			To 2020	To 2030	To 2040	To 2050
Heat	Heat displaced	TWh pa	0.0	14.1	29.0	29.0
Absolute Values						
Fossil gas	Levelised cost of heat	£/MWh	59.2	62.8	63.9	63.9
	Annual Cost	£M pa	0	886	1,852	1,852
	Cumulative Net Present Value by decade	£M (NPV)	0	1,893	10,458	17,438
	Carbon intensity (delivered heat)	kg/MWth	232	228	228	228
	Annual emissions	000 te pa	0	3,222	6,611	6,611
	Cumulative emissions by decade	000 te	0	10,287	69,104	135,214
Absolute Values						
Heat pumps	Levelised cost of Heat (excl reinforcement)	£/MWh	139.2	130.1	124.1	118.5
	Annual Cost (inc reinforcement)	£M pa	0	2,239	3,605	3,449
	Cumulative Net Present Value by decade	£M (NPV)	0	5,341	23,694	36,984
	Carbon intensity	kg/MWth	85	29	15	1
	Annual emissions	000 te pa	0	408	428	42
	Cumulative emissions by decade	000 te	0	135	7,004	9,158
Absolute Values						
Hydrogen	Levelised cost of heat	£/MWh	143.1	107.3	104.4	101.8
	Annual Cost	£M pa	0	1,514	3,025	2,950
	Cumulative Net Present Value by decade	£M (NPV)	0	3,443	17,669	28,924
	Carbon intensity	kg/MWth	77	30	27	22
	Annual emissions	000 te pa	0	430	774	651
	Cumulative emissions by decade	000 te	0	1,574	8,890	15,953
Comparisons						
Carbon	Cumulative savings by heat pump relative to fossil gas	000 te	0	10,152	62,100	126,057
	Cumulative savings by hydrogen relative to fossil gas	000 te	0	8,714	60,214	119,262
Costs	Cumulative decarbonisation by heat pump relative to fossil gas	£M (NPV)	0	3,447	13,236	19,546
	Cumulative decarbonisation by hydrogen relative to fossil gas	£M (NPV)	0	1,550	7,210	11,486
Savings	Cumulative decarbonisation by hydrogen compared with heat pump	£M (NPV)	0	1,897	6,025	8,060

Absolute Values for GB at 10% (Method 2)			To 2020	To 2030	To 2040	To 2050
Heat	Heat displaced	TWh pa	0.0	7.1	14.5	14.5
Absolute Values						
Fossil gas	Levelised cost of heat	£/MWh	59.2	62.8	63.9	63.9
	Annual Cost	£M pa	0	443	926	926
	Cumulative Net Present Value by decade	£M (NPV)	0	947	5,229	8,719
	Carbon intensity (delivered heat)	kg/MWth	232	228	228	228
	Annual emissions	000 te pa	0	1,611	3,306	3,306
	Cumulative emissions by decade	000 te	0	5,144	34,552	67,607
Absolute Values						
Heat pumps	Levelised cost of Heat (excl reinforcement)	£/MWh	139.2	130.1	124.1	118.5
	Annual Cost (inc reinforcement)	£M pa	0	1,120	1,803	1,725
	Cumulative Net Present Value by decade	£M (NPV)	0	2,670	11,847	18,492
	Carbon intensity	kg/MWth	85	29	15	1
	Annual emissions	000 te pa	0	204	214	21
	Cumulative emissions by decade	000 te	0	67	3,502	4,579
Absolute Values						
Hydrogen	Levelised cost of heat	£/MWh	149.0	113.1	109.9	107.3
	Annual Cost	£M pa	0	798	1,591	1,553
	Cumulative Net Present Value by decade	£M (NPV)	0	1,815	9,299	15,223
	Carbon intensity	kg/MWth	77	30	27	22
	Annual emissions	000 te pa	0	215	387	325
	Cumulative emissions by decade	000 te	0	787	4,445	7,976
Comparisons						
Carbon	Cumulative savings by heat pump relative to fossil gas	000 te	0	5,076	31,050	63,028
	Cumulative savings by hydrogen relative to fossil gas	000 te	0	4,357	30,107	59,631
Costs	Cumulative decarbonisation by heat pump relative to fossil gas	£M (NPV)	0	1,724	6,618	9,773
	Cumulative decarbonisation by hydrogen relative to fossil gas	£M (NPV)	0	868	4,070	6,504
Savings	Cumulative decarbonisation by hydrogen compared with heat pump	£M (NPV)	0	855	2,548	3,269

Project code	**NGGDGN03/1**	**Question Number**	**2**
Question date	**230816 (delivered 310816)**	**Answer date**	**020916**
Submission section question relates to	**3.3.1**		
Topic	**Benefits**		
Question	**The fall in the levelised cost of hydrogen is a critical driver of the benefit estimate as shown in Table B4. In particular Bio-SNG which is itself in infancy. Can it be clarified how the risks associated with this source of hydrogen have been accounted for in the assessment of benefits?**		
Notes on question			
Answer	The cost base for bio-hydrogen production is based on the work undertaken on the BioSNG project. In that project, costs of commercial scale projects were assessed in detail, for both early projects and 'nth' of a kind. This work demonstrated that this route could provide substitute natural gas at price parity with fossil gas over the course of the 2020's. Production of hydrogen is a simpler process, requiring only a shift, rather than the full methanation of the syngas. Furthermore, the methanation catalysts are substantially more sensitive to impurities and so the upstream gas processing is also much simpler for hydrogen production. However, for the purposes of this assessment, the capital costs have not been reduced accordingly. Furthermore, for this application, the smaller scale and plant size has also been assumed. Therefore, whilst it is plausible that hydrogen could be produced by this route at a similar cost on an energy basis to natural gas, the cost of hydrogen production used in this assessment is conservatively taken to be much higher. A further sensitivity analysis has been undertaken as shown in the table below. Increasing the cost of biohydrogen by a further 10% has the following impact on the benefits, reducing the 2050 NPV from £8,060m to £7,287m for the 20% case and from £3,269m to £2,840m.		

Cumulative NPV	Blend rate (Method)	To 2020 £million	To 2030 £million	To 2040 £million	To 2050 £million
GB Values	20% Blend (M1)	0	1,771	5,518	7,287
	10% Blend (M2)	0	785	2,267	2,840
Licensees Values (63% of GB)	20% Blend (M1)	0	1,116	3,476	4,591
	10% Blend (M2)	0	495	1,428	1,789
Post Trial	Either blend	0	0.4	0.7	0.7

Were costs to increase beyond this, then CCS+SMR would be a lower cost solution and would play a greater role in delivering the hydrogen required.

In summary, the risks associated with bio-hydrogen have been addressed through conservative initial figures, a sensitivity assessment, and the fact that at this level the costs are the same as CCS+SMR which provides an alternative supply route.

Attachments	

Project code	**NGGDGN03/1**	**Question Number**	**3**
Question date	**230816 (delivered 310816)**	**Answer date**	**020916**
Submission section question relates to	**3.3.1**		
Topic	**Benefits**		
Question	**Can it be clarified how net benefits have been derived? In particular, what assumptions are made about additional R&D costs, what system wide costs would be incurred (eg for full H2 deployment - Dodds and Demoullin estimated conversion costs of £500 per household). Could the levelised costs be used to show analogous figures.**		
Notes on question			
Answer	The purpose of this project is to assess and demonstrate the level of hydrogen blend which can be delivered across the gas distribution network *without* requirements for changes to consumer appliances, installations or the network. The figures cited from Dodds and Demoullin are the costs per household for the conversion of their appliances, detectors and meters to operate on 100% hydrogen. These costs do not exist for the route proposed by HyDeploy. The HyDeploy project is designed to provide the core R&D required to establish this route for decarbonisation. However, there are some additional development costs, which are acknowledged: • As laid out in the bid, it is expected that a follow on trial on a public network will be necessary prior to wider roll out. This is expected to be a lower cost project than this first HyDeploy trial, both because much of the core science and evidence base will be developed and collated in HyDeploy, but also because key equipment can be transferred to such a trial. • Adoption of hydrogen as a blend is likely to require changes to billing methodologies. Alternative sources of natural gas already mean that the existing Flow Weighted Average CV approach needs review; hydrogen-blending is another factor which supports the need for change in this area. This work is already being addressed through the Future of Billing Methodology NIC proposal. • HyDeploy is based on blending hydrogen into the distribution system.		

	The vast majority of the consumption will be for the provision of heat. However, it is recognised that there will also be CHP engines and similar small generators on the system. These will have different sensitivities to hydrogen blends compared with conventional heating demands. NGGD and NGN have already identified this, and are proposing to develop an NIA project to investigate it. It was decided that this should be separate from the NIC project due to the different nature of the investigation. However, this can be cost effectively hosted at the Keele site, using a CHP unit on the campus. • It is expected that there is also a role for auxiliary R&D work, such as providing more cost effective gas analysis equipment for hydrogen – natural gas compositional measurements for injection sites. Whilst these R&D costs are in addition to HyDeploy, combined they are expected to be less than the cost of the current proposal. Therefore, against a decarbonisation route which has the potential to save £8billion, they would not substantially change the economic justification.
Attachments	

Project code	**NGGDGN03/1**	**Question Number**	**4**
Question date	**230816 (delivered 310816)**	**Answer date**	**020916**
Submission section question relates to	**3.3.1**		
Topic	**Benefits**		
Question	**Cost/carbon savings are based on 10% and 20% hydrogen blends- is there a risk that 10% may not be achievable once appliance testing etc. is conducted?** **"avoidance of network reinforcement otherwise required" is included in cost savings. Should it not be acknowledge that network reinforcement may be needed for reasons other than heat pump deployment i.e. electrification of vehicles?**		
Notes on question			
Answer	This project builds on substantial work which has been carried out both in the UK and in Europe into the blending of hydrogen into gas networks. Key examples are: • The Ameland Project in Holland (2007-2011) where blends of up to 20% were injected. • The HSE (2015) issued a literature review which observed that '*concentrations of hydrogen in methane of up to 20% by volume are unlikely to increase risk from within the gas network or from gas appliances to consumers or members of the public.'* • In Germany parts of the network are already permitted to deliver 10% hydrogen into the network In addition both HSL and DNV-GL through the HyStart project have reviewed the situation with regards to blends in the UK context and have concluded that there is no reason why a blend between 10-20% should not be feasible in the distribution system. Therefore there is confidence that this is a reasonable approach. However, it is recognised that this is an *innovation* project, and that the purpose of it is to provide the sound, detailed evidence base for hydrogen blends in the UK. Therefore it is possible that the programme could identify particular unforeseen reasons why the blend level may not be achievable. The outcome of this could either be a lower level of blend across the		

	network, or very specific changes which could be required. In this case, part of the output of this project would be to recommend the appropriate route forward and a successful outcome could be below 10%. The level of network reinforcement required has been based on the level of capacity specifically required to deliver the number of heat pumps identified in the scenario. In this case a total reinforcement capacity of 8.8GWe for the 20% case with a discounted cost of £2,640m across transmission and distribution. Other assessments of widespread electrification of energy have substantially higher levels of assumed reinforcement capacity to accommodate greater levels of heat pumps as well as vehicle electrification etc (For example Delta[3] indicated a discounted cost of £12-20,000m of reinforcement costs for such a scenario). In reality partial reinforcement may be challenging given the potentially diverse geographical uptake of heat pumps. Therefore it is acknowledged that network reinforcement may be required for wider reasons, but the figures used here are conservative, particularly recognising that other costs, such as associated increases in generation capacity have not been included. References [1]PILOT PROJECT ON HYDROGEN INJECTION IN NATURAL GAS ON ISLAND OF AMELAND IN THE NETHERLANDS, M.J. Kippers et al, International Gas Union Research Conference 2011 [2]Injecting Hydrogen into the gas network – a literature search' Hodges et al HSE (2015) [3] "2050 Pathways for Domestic Heat" Delta EE, October 2012
Attachments	

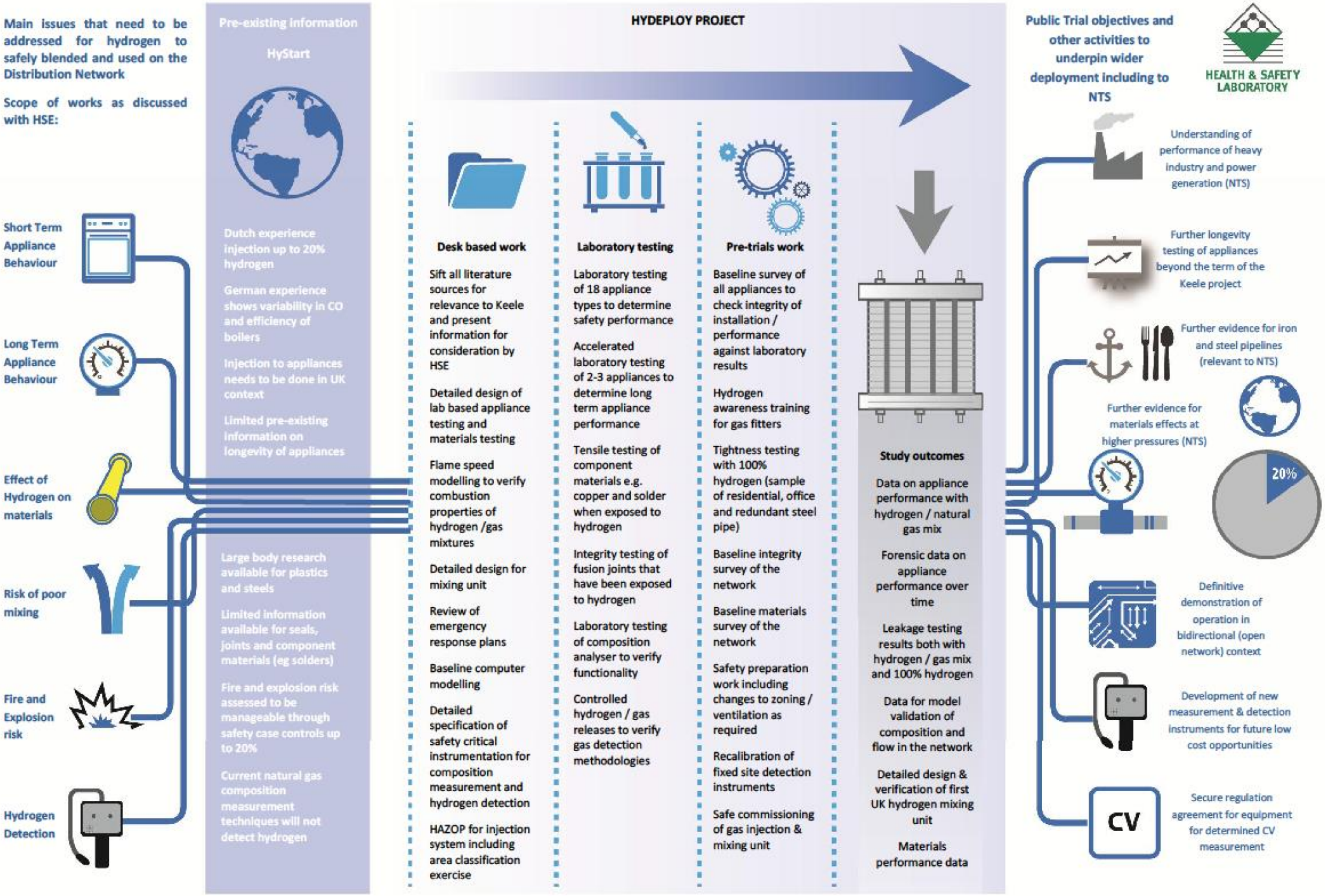
Project code	**NGGDGN03/1**	**Question Number**	**5**
Question date	**250816 (delivered 310816)**	**Answer date**	**020916**
Submission section question relates to	**2.3.3**		
Topic	**General**		
Question	**Does the 'accredited by Ofgem' reference under composition measurement and CV refer to what you are looking for a view from Ofgem on in section 7 of your submission?**		
Notes on question			
Answer	In context, the statement is: *"Wider deployment requires confidence that existing network pressure and flow measurements remain suitable. New analysis equipment supplied with hydrogen-blend entry units must be robust and reliable, and able to be accredited by OFGEM. Early enabling work on this process will be undertaken in this project to support next stage roll out. HyDeploy could act as a test bed for instrumentation developed by others."* It is proposed for the trial to use a 'Declared' CV basis for billing purposes (see Section 7 and Clarification Question 6). However, looking to wider deployment in the future, it is recognised that it will be necessary to measure the gas composition in hydrogen injection units using suitable instrumentation acceptable to OFGEM, and securing its approval (a 'Letter of Direction') will take time. Therefore, even though this is not necessary to execute the trial itself, the project partners are keen to support development/approval of such equipment and the project provides a useful test bed. For example, currently there are two Gas Chromatography (GC) units for measurement of gas composition which have Letters of Direction. These units are also able to use the approved DANNIT software. Therefore, to the extent that the experimental equipment used for the project could be commercially available GC units, then (a) such units would be more straightforward to secure approval than other technologies and (b) the project itself would expedite the approval process by providing valuable operational data. Equally it is recognised that there may be an opportunity for others to develop alternative lower cost techniques, in which case the		

	project provides a site to test such equipment, although the development pathway is expected to be longer.
Attachments	

Project code	**NGGDGN03/1**	**Question Number**	**6**
Question date	**250816 (delivered 310816)**	**Answer date**	**020916**
Submission section question relates to	**Section 7**		
Topic	**General**		
Question	**While we may have a view on the use of declared vs determined CV, does Ofgem have a formal role to approve the choice taken by NGGD?** **Broadly, what does the process for this look like and what are the timings be?**		
Notes on question			
Answer	Yes, OFGEM will have a role in approving the choice taken by NGGD with regard to Calorific Value for the purposes of billing. The Declared CV approach is one which is permitted by the Gas (Calculation of Thermal Energy) Regulations (part III). For example it is used within the Scottish Independent Undertakings. The network proposed for the HyDeploy project is a closed network with a single point of entry. As noted in the application, the vast majority of the gas supplied by Keele is consumed within its own buildings, therefore the volume of gas and number of customers affected is small, and so this is considered to be the most appropriate method to safeguard their interests. As part of the project, the team will develop the evidence base to submit to OFGEM, justifying the approach, and how it will ensure that the customers on the network are not disadvantaged. This will also include the proposed basis to set the CV, as well as how the CV will be periodically tested to demonstrate that the figure used is conservative in favour of the customers. OFGEM will then review the evidence to determine approval. On public networks the proposed CV must be advertised in appropriate publications three months prior to being implemented. In this case, as part of the communications plan it will be possible to inform all relevant customers directly. Whilst the overall process may be time consuming to secure approval, injection of hydrogen is not scheduled until 24 months after commencement		

	of the project, and therefore it is not perceived as a major risk to the project programme. The project team will commence this process at the start of the project, and expects to be able to agree the approach with Ofgem by the end of the first phase (end of Q4 of the programme).
Attachments	

Project code	**NGGDGN03/1**	**Question Number**	**7**
Question date	**090916**	**Answer date**	**150909**
Submission section question relates to			
Topic			
Question	**Please can you provide more information on what are the main the issues that need to be addressed for hydrogen to safely blended and used on the distribution network? This should be in the form of a chart/checklist including evidence required by HSE. If there are differences if the NTS is used please highlight those too.**		
Notes on question			
Answer	Please see Attachment which shows infographic which answer this question		
Attachments	NGGD_HyDeploy_090916_Q7_Attachment.pdf		


Main issues that need to be addressed for hydrogen to safely blended and used on the Distribution Network
Scope of works as discussed with HSE:
Short Term Appliance Behaviour
Long Term Appliance Behaviour
Effect of Hydrogen on materials
Risk of poor mixing
Fire and Explosion risk
Hydrogen Detection
Pre-existing information
HyStart
Dutch experience injection up to 20% hydrogen
German experience shows variability in CO and efficiency of boilers
Injection to appliances needs to be done in UK context
Limited pre-existing information on longevity of appliances
Large body research available for plastics and steels
Limited information available for seals, joints and component materials (eg solders)
Fire and explosion risk assessed to be manageable through safety case controls up to 20%
Current natural gas composition measurement techniques will not detect hydrogen
HYDEPLOY PROJECT
Desk based work
Sift all literature sources for relevance to Keele and present information for consideration by HSE
Detailed design of lab based appliance testing and materials testing
Flame speed modelling to verify combustion properties of hydrogen /gas mixtures
Detailed design for mixing unit
Review of emergency response plans
Baseline computer modelling
Detailed specification of safety critical instrumentation for composition measurement and hydrogen detection
HAZOP for injection system including area classification exercise
Laboratory testing
Laboratory testing of 18 appliance types to determine safety performance
Accelerated laboratory testing of 2-3 appliances to determine long term appliance performance
Tensile testing of component materials e.g. copper and solder when exposed to hydrogen
Integrity testing of fusion joints that have been exposed to hydrogen
Laboratory testing of composition analyser to verify functionality
Controlled hydrogen / gas releases to verify gas detection methodologies
Pre-trials work
Baseline survey of all appliances to check integrity of installation / performance against laboratory results
Hydrogen awareness training for gas fitters
Tightness testing with 100% hydrogen (sample of residential, office and redundant steel pipe)
Baseline integrity survey of the network
Baseline materials survey of the network
Safety preparation work including changes to zoning / ventilation as required
Recalibration of fixed site detection instruments
Safe commissioning of gas injection & mixing unit
Study outcomes
Data on appliance performance with hydrogen / natural gas mix
Forensic data on appliance performance over time
Leakage testing results both with hydrogen / gas mix and 100% hydrogen
Data for model validation of composition and flow in the network
Detailed design & verification of first UK hydrogen mixing unit
Materials performance data
Public Trial objectives and other activities to underpin wider deployment including to NTS
HEALTH & SAFETY LABORATORY
Understanding of performance of heavy industry and power generation (NTS)
Further longevity testing of appliances beyond the term of the Keele project
Further evidence for iron and steel pipelines (relevant to NTS)
Further evidence for materials effects at higher pressures (NTS)
20%
Definitive demonstration of operation in bidirectional (open network) context
Development of new measurement & detection instruments for future low cost opportunities
CV
Secure regulation agreement for equipment for determined CV measurement

Project code	**NGGDGN03/1**	**Question Number**	**8**
Question date	**090916**	**Answer date**	**150916**
Submission section question relates to			
Topic			
Question	**"The cost of buying and installing an electrolyser onsite makes up a large sum of the cost of the project.** **(i) Why does hydrogen need to be produced by an electrolyser onsite rather than shipped in?** **(ii) Could the electrolyser be rented rather than bought? Please could you provide the costs of renting, if that is possible, compared to buying the electrolyser. Alternatively can it be purchased second hand? Is possible, please provide the cost of a second hand electrolyser and it's expected lifetime.** **(iii) Can you provide costings and risk assessment of having hydrogen brought and used from a safe place on the campus, compared to procuring and using an electrolyser onsite."**		
Notes on question			
Answer	*(i) Why does hydrogen need to be produced by an electrolyser onsite rather than shipped in?* Both approaches have the potential to deliver the core project outcome required. However the university has always had safety concerns about large inventories of pressurised hydrogen onsite. This has informed the project strategy proposed in the bid, where hydrogen is produced on demand by the electrolyser. The attributes of both approaches are summarised in Table 1 overleaf, and a cost assessment is described in Section (iii) below, along with Table 2. The volume of hydrogen required for the demonstration phase would require a pressurised hydrogen storage facility to be built on the university campus if it is not produced onsite. Given the level of demand and the requirements for cost effective delivery of hydrogen, storage would be on an industrial level rather than in university research quantities. The University has a requirement to minimise the potential impact on the campus, students and		

	staff of such a facility and would have an obligation to ensure that risks are managed and appropriate procedures and policies are in place, compliant with necessary legislation. This would not be such an issue on an appropriately selected industrial site, but is viewed differently on a residential campus. The project has been designed with the co-location of the hydrogen production unit and grid entry unit at the university energy centre at the heart of the campus with associated infrastructure. The electrolyser produces hydrogen at low rates (2.5g/s), with production stopped in under 1 second in emergency conditions, therefore inventories are extremely low. As discussed in Section (iii) below, cost-effective delivery and security of supply requires volumes of between 0.25 and 0.5 tonnes of hydrogen (the equivalent of over 500 conventional gas cylinders). Therefore such a solution would require that the hydrogen is stored away from existing facilities and dwellings at the edge of the campus. This entails additional cost for further pipeline infrastructure and implications of services and operation of the facility. Vehicle delivery must also be managed safely with appropriate gas manifolding and drive away protection and emergency shut down facilities. The Keele site and the nature of its main access routes mean that additional lorry movements are a concern for the university and its community. It has previously rejected plans to convert one of the boiler houses on campus to biomass due to the need to have 2-3 lorry movements a week on campus. This is the same level that would be required over the winter for hydrogen deliveries. There are also some concerns about access in poor winter weather conditions. With more infrastructure compared with an electrolyser solution, these costs are sunk and would require appropriate reinstatement following the project. Assuming that as planned, the Keele trial is followed by a trial on the public network, the electrolyser will be transferred, delivering enduring value from the asset through ongoing lower cost hydrogen production - a key benefit of this approach. Electrolysis is one of the potential sources of hydrogen for blending in the future. Whilst not a core focus of the project, a supplementary benefit of the use of an electrolyser is to provide valuable long term operational data under real gas network load-following conditions. In summary, the proposed project approach of using an electrolyser avoids key risks and offers a number of benefits. However, it is recognised that this needs to be assessed against the costs, which are shown in part (iii). *(ii) Could the electrolyser be rented rather than bought? Please could you provide the costs of renting, if that is possible, compared to buying the electrolyser. Alternatively can it be purchased second hand? Is possible, please provide the cost of a second hand electrolyser and it's expected lifetime.* The market for electrolysers of this scale for the production of hydrogen is not yet mature. Therefore no suppliers, including ITM, operate leasing

business models for their products.

Similarly, there is not yet a second hand market for this type of electrolyser, with no evidence of suitable second hand products currently available for sale in the UK, Europe, US or Canada. Furthermore, the project team and Keele in particular would have strong reservations about safety and operability of such a unit. Having the operational support and commitment to process integrity from the Original Equipment Manufacturer is vital to deliver the project safely and to schedule.

However, as part of their commitment to the project, ITM have agreed to a buy-back option for the electrolyser; 50% before on-site commissioning, 25% post on-site commissioning. This non-standard commercial provision has been offered specifically for this project, which goes some way towards a rental model. This important provision has been included in the assessment below.

(iii) Can you provide costings and risk assessment of having hydrogen brought and used from a safe place on the campus, compared to procuring and using an electrolyser onsite.

The key attributes and risks of the two approaches are summarised in Table 1 below, and the costs compared in Table 2. Both the risks and costs are supported by the narrative below. In summary this shows that whilst there are some cost savings to be made for the trial at Keele through buying hydrogen and storing onsite, these are relatively limited, particularly when reviewed against the increased project risk profile. Assuming that as planned, the Keele trial is followed by a trial on the public network, the electrolyser will be transferred to continue to deliver further lower cost hydrogen.

Risks

A pressurised hydrogen storage facility on the Keele University campus site would have to comply with current legislation, and the University would have to show that it had met its duty of care obligations with appropriate safety cases developed.

Within the UK, the current legislation associated with the storage and handling of large volumes of dangerous materials are covered by the Control of Major Accident Hazards (COMAH) Regulations 2015. The regulation seeks to allow the identification of sites for major hazard, ensure control measures are in place to prevent major accidents and mitigation measured are in place to limit the effects of accidents. Whilst the volumes of gas expected to be stored would fall below the requirements for formal compliance under COMAH, the quantities are sufficiently material that the University would be seeking to ensure that its policies and procedures follow best practice and guidelines set out under these regulations.

Subject to confirmation of storage requirements based on efforts to minimise footprint and delivery frequency by tube trailer, planning permission would have to be sought and the local planning authority could impose limits on the capacity of the facility and make it a requirement to

	prepare accident prevention policies to address major accident hazards and for the protection of people and the environment which must be made available to contractors and employees at the site. In addition hazardous substances consent would be required. Specific risk attributes of storage as compared with the electrolysis approach are shown in Table 1. **Basis for the costing comparison** Campus siting: To seek to address concerns regarding a large inventory of pressurised stored hydrogen, sites have been identified towards the edge of the Keele University campus, as shown in Figure 1 overleaf. Currently the most appropriate site is considered to be Plot 12 with sufficient available area (although the University is considering utilising an existing test well on part of this site for research / geothermal energy production, which could present a project risk). Note that building work is already under way on adjacent plots. Pipeline configuration: The project has been designed with the co-location of the hydrogen production unit and grid entry unit at the university energy centre at the heart of the campus with associated infrastructure. Two revised configurations with storage were considered: (a) Location of just the hydrogen storage facility at Plot 12, with a dedicated hydrogen pipeline to the grid entry unit located at the Horwood Energy centre as before. Whilst this solution is least disruptive and shorter (900m), the minimum pipeline methodology recommended by the British Compressed Gases Association (BCGA), and required by current hydrogen users such as Shell is for seamless stainless pipelines in concrete ducting. Combined, the lay cost of this approach is over ten times more expensive per metre than conventional gas piping. (b) Location of both the hydrogen storage facility and grid entry unit at plot 12. This requires a longer pipe run (1600m length) as it requires an additional natural gas pipeline from the university to plot 12 and then the blended pipeline from Plot 12 to the existing G3 meter. However, this is consistent with the wider project, using conventional PE pipelines and lay methods and so substantially cheaper, even after accounting for the additional services required at the remote site. For the assessment here, this approach is assumed. Storage type: three types of storage were considered; Multi Cylinder Packs (MCPs) , trailers and dedicated storage. Hydrogen delivered by MCPs costs around 10 times that by trailer and for winter usage would require changeover every two hours at 20% blend. Trailers hold between 225-500 kg of storage depending on pressure (typically 200-350 barg) and length between 5.8-11.6m plus tractor unit. Purchase costs are between £180,000-£670,000 each depending on type and pressure, with dedicated storage solutions having similar characteristics. However, 200 barg trailers holding 225kg of usable gas (requiring changeover 2-3 times per week during the winter at 20% blend) can be hired from the major gases companies, offering

	the most competitive solution for this application, and form the basis of the cost assessment. In all cases, decanting facilities including drive away protection, pressure reduction, gas distribution manifolding, emergency shut down facilities are required on site. <u>Costing data:</u> Where possible figures for comparison have been secured from suppliers such as the major gases companies, which are based on established supplier customer relationships, and estimates based on data developed in the initial bid. Assumptions have been included in Table 2. The assessment of costs includes only the direct costs applicable to the solution. It does not factor in the costs associated with managing the additional risks associated with the storage route. For example, it is clear that the management at Keele University has reservations about such an inventory of gas on its site, and so it is expected that there will be additional costs incurred to develop and present the safety case to their satisfaction. The costs are shown for the initial trial and Keele University only. The electrolyser asset is readily transferable, unlike the sunk infrastructure costs associated with storage. The expectation is that the hydrogen production equipment will be transferred to a follow on trial on a public network. Use of this asset allows continued lower cost hydrogen delivery, particularly where sited to exploit opportunities for lower cost electricity. <u>Summary:</u> As shown in Table 2, there are some cost savings to be made for the trial at Keele using the delivery and storage solution. However, these savings, of the order of £90,000, are relatively limited particularly when reviewed against the increased project risk profile discussed above and shown in Table 1. Assuming that as planned, the Keele trial is followed by a trial on the public network, the electrolyser will be transferred to continue to deliver further lower cost hydrogen, expected to more than offset the storage savings
Attachments	See 2 Tables and 1 Figure below

Attribute	Electrolyser	Storage	Implications
Campus location	Located at the energy centre with good access to all services	Located at the edge of the campus with additional pipeline and services connections required.	Project Cost
Site availability	Site already secured for project as part of development to date	Identified site have potential competing uses, which represent a project delivery risk	Project delivery risk
Site & infrastructure	Existing developed area with hard standing	Greenfield development	Project Cost
Foot print	One Iso Container, integrated into existing GEU footprint	Min 3 x footprint for storage plus necessary turning circle allowance for HGV delivery	Project Cost
Gas pressures	Gas delivery pressure at 2 barg to match the gas network	Storage at 200 barg	Safety risk requiring management
Potential hydrogen release volumes	With response times under 1s, and production rate of 2.5g/s, therefore limited	Storage inventory in excess of 225kg ; would require appropriate protection measures	Safety risk requiring management
Opportunity for release	Short, single and permanent pipeline to the grid entry unit	Multiple and longer length pipelines	Safety risk requiring management
Connections	Single iso container with 3 connections directly to the grid entry unit	Multiple manifolding, requiring safe drive away connections etc	Project Cost and Safety risk
Continuity of supply	Only relies on continuity of electricity supply, which is good.	Subject to maintain HGV transport access during the winter at peak demand. In extremis the road access to the campus (on a hill) can be severely restricted in the winter months due to ice and snow.	Project disruption / data quality
Delivery requirements	Once equipment delivered non-disruptive	Regular HGV deliveries 2-3 per week. Campus rejected a biomass boiler with similar transport requirements on these grounds	Project Delivery risk
Project programme	Whilst the electrolyser procurement forms a substantial part of the phase 2 schedule, the Grid Entry Unit lead time is the same length, 'gating' the programme	Delivered hydrogen avoids the build time for the electrolyser, but the benefit cannot be realised.	No impact
Follow on project	Asset available for subsequent public trial, substantially reducing reduce costs	On the basis of trailer rental, additional investment in local infrastructure, so not transferable to public trial	Cost implications for follow on trial
Additional attributes, learning opportunities	Ability to secure evidence of electrolyser performance when load following gas demand under long term operational conditions	Some learning regarding storage, but considered to be BAU for appropriately selected sites in the future	Missed opportunity

Table 1: Attributes of Electrolyser and Delivery and Storage Solutions

Base Case Electrolyser				Delivered Hydrogen & Storage Comparison		
Fixed Costs	**£**	**Comment**		**Fixed Costs**	**£**	**Comments**
Electolyser Equipment costs	676,962	Taken from bid		Trailer unloading manifolds etc	75,000	Equipment Estimate provided by Gas supplier (trailers assumed to be hired as variable cost, below)
Factory Acceptance testing	36,120	Taken from bid, electrolyser only		Civil costs for site	115,000	Additional costs for larger site to accommodate two trailers plus HGV movements and greenfield site. Costs estimated based on initial project figures
Installation	15,881	Taken from bid, electrolyser only		Local control room	6,000	Orginally using Horwood Energy Centre. Assumes Portacabin Hire and installation
Commissioning	53,631	Taken from bid, electrolyser only		Communications	12,000	Provision for secure IT services to control room (formerly integrated into Energy Centre)
				Additional pipelines	208,000	Additional pipeline from university natural gas offtake to Plot 12 , and return line for blended gas back to G3 meter (total additional length of approx 1600m compared with base case). Based on PE pipeline lay costs of £13,000/100m.
Total	**782,594**			**TOTAL**	**416,000**	
Variable cost of hydrogen	123,120	Based on 20 tonnes per annum and Keele's prevailing electricity cost.		Variable cost of hydrogen	203,000	Based on 20 tonnes per annum. Data provided by Gas supplier. Trailer usable capacity of 225kg. Driver charge of £55/hr, Mileage at £1.15/mile, Call out of £80/delivery and based hydrogen at £50/HCM. Equates to £7150/te delivered cost plus hire charges for trailers (£5000/month) for 12 month period
Buyback provision	-195,000	25% as provided by ITM				Not Applicable
Net project costs	**710,714**				**619,000**	
Net saving using storage					**91,714**	Keele trial only; expected to be more than offset in public trial

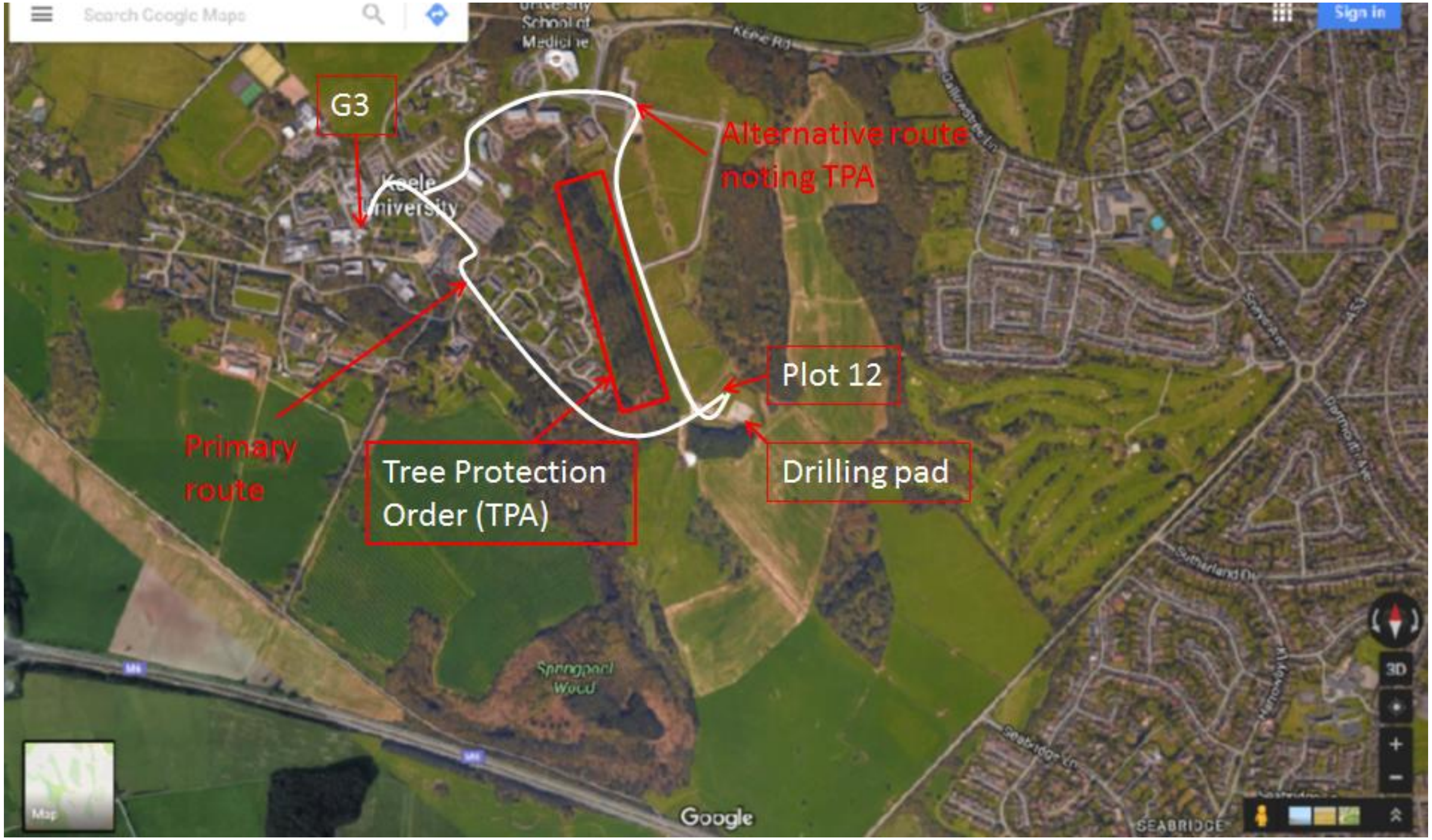


Figure 1 Site locations and routing

Project code	**NGGDGN03/1**	**Question Number**	**9**
Question date	**090916**	**Answer date**	**150916**
Submission section question relates to	**8**		
Topic	**Customer Engagement Plan**		
Question	**(i) Please can you provide a high level customer engagement plan that will be used for customers onsite and the learning taking from Oban?** **(ii) Please can you include as an explicit project deliverable, the consolidation of work and learning on customer engagement for future trails of hydrogen on the public network?**		
Notes on question			
Answer	(i) As set out in Section 8 of the HyDeploy Bid document and in line with NIC Governance requirements, the final Customer Engagement Plan will have a structure and content which draws on the knowledge and experience acquired from similar previous engagement with customers, notably in the SGN Oban project. It is anticipated the Engagement Plan will be set out with a structure as indicated in the Overview below. The HyDeploy project is aware of the importance of well managed and clear customer engagement. At its heart is communicating the importance of addressing climate change and the carbon implications of the heat we consume, as well as how this solution provides a non-disruptive solution for the UK consumer. In addition to informing the customers about the benefits and the integrity of the project structure, the strategy must also recognise the fact that we are doing something which is new and so, because of this, customers will have concerns about risk and impact on their day-to-day lives. So there is a need to communicate effectively and sensitively, majoring on the fact that hydrogen has been used in the UK before, focusing on the quality of the project planning and the team, particularly HSL, and the fact that nothing will be taking place without the HSE’s agreement. Whilst the immediate focus of the HyDeploy project is on the Keele network and customers, it is also important to recognise that the customer engagement undertaken has wider implications for the future and the way customers are handled and the effectiveness of the process will be essential learning for the anticipated further roll-out to a public network. This also		

	includes the learning and benefits from the NG staff we will be training, and the appliance / boiler manufactures with whom we engage. (ii) The learning about the communications plan will be included in the Public trial development; we will make this an explicit part of the SDRC 9.9, viz "Completion of definition of follow on network trial, including application of learning from the Keele customer engagement plan". **HyDeploy Customer Engagement Plan Overview** **Executive Summary** **1. Introduction** • This will explain the project background against the backdrop of climate change targets and heat decarbonisation, including the specific opportunities afforded by the Keele site. • The requirement for an engagement plan will be explained and its structure will apply learning from various relevant sources e.g. the Oban project. • The project's commitment to customers, notably Priority Services Customers, in terms of service continuity, safety and commercial integrity will be set out and this will be reflected throughout the Plan. • Plan to be signed off by both OFGEM and Keele Ethics Committee before any customer engagement takes place **2. Proposed interactions with customers** This will cover the proposed set of communications and the customer experience, including: • Initial customer contact and engagement e.g. initial information meetings, leaflets, information line • Appliance testing and replacement: what the customer can expect on the day and the support that will be given in terms of making convenient appointments and after-care • Continuing monitoring during field trial • Continuing customer support for problems or concerns • Close-out event to thank customers and present results Further details about the methods and content will be given in the Communications Strategy below. **3. Audience** • The key audience is our Keele customers, both domestic and departmental which are the equivalent of a small town with the

	following makeup: ◦ 67 Academic and Science Park buildings ◦ 152 student residential buildings ◦ 101 staff flats and houses – 47 owned by Keele and rented, 54 owner-occupied • The project starts with a key advantage of Keele University having a close relationship and knowledge of each of the properties included in the test site. Hence the target audience is well researched and segmented already. • The project will address anticipated customer expectations and also take into account customer feedback **4. Communications strategy** The communication strategy will be comprehensive and use various media to achieve the goals: • Core messages to key target audiences of what, when, why and how. This will draw upon known public perceptions of gas appliances, climate change and, in particular, hydrogen using work such as the proposed NGN & Newcastle University NIA on *Hydrogen in Everyday Energy Use: Perceptions, Practices and Possibilities.* • Desired outcome and outputs will be set out clearly in line with the project plan. • Channels for engagement: meetings, drop-in sessions, household and general leaflets, website, social media, customer care line etc. • Branding of the project to establish a clear identity with customers and stakeholders involved in the project. • Communications phasing through the project; initial focus on awareness and answering concept and start-up questions (what, why, when, how), followed by regular update and feedback focus. • Communications framework map to ensure all communications are well integrated and also in line with Keele University communications standards. • Notifying Customers – covering formal notifications. **5. Safety information** • Our safety culture: Safety is paramount in everything we are proposing to do at Keele and all project operations are to be approved by The Health and Safety Executive and Keele University. • The project team consists of world-leading organisations in the field of safety including as the Health and Safety Laboratories and Kiwa

	GasTech. • Customer assistance: “don’t walk by” if notice unexpected issues or are concerned about any aspect of safety. • Risks: risk register, particularly customer-facing issues • Unsafe situations procedure • Data Protection: identification and procedures (see below) **6. Customer consent** Because of the nature of the site and the type of people affected, the issue of customer consent may be more straightforward than in a public setting. However, this does not mean the topic is taken lightly and this section will set out the approach to: • Obtaining and documenting customer consent • Customer participation **7. Data Protection Strategy** Keele University already has a relationship with all the customers on site and an existing data Protection Strategy. This will form the basis of the project DP strategy to be agreed with OFGEM and the Keele Ethics Committee. It will deal with issues such as: • What personal data will we collect for the purposes of the project? • How will personal data we collect be used? • Who will we share personal data with? • How will consent for use of the personal data be obtained? • Who owns the personal data? • How will data or analysis be published? • How will we ensure we store and manage personal data securely? • Compliance with NG and Keele standards and policies
Attachments	

Project code	**NGGDGN03/1**	**Question Number**	**10**
Question date	**090916**	**Answer date**	**150909**
Submission section question relates to			
Topic			
Question	**Part of the project plan identifies that a 6” steel pipe must be inspected.** **(i) Why does this pipe need to be inspected? Would the inspection be needed if the project doesn’t go ahead?** **(ii) What is the mitigation if repairs are needed to the pipe? Are these costs included in the project cost? Given its depreciated cost vs new asset life should Keele make a contribution if it is replaced.**		
Notes on question			
Answer	The questions are briefly answered, then amplified in the narrative below. (i) To clarify, the pipeline is routinely *inspected* as part of business as usual; what has been identified and costed is the fact that the pipeline requires *replacement* in order to risk manage execution of the project and to enhance the data provided, as described below. (ii) The mitigation already identified is the replacement of the pipeline, as well as configuring and setting up the old pipeline element for dedicated testing. These costs have already been included in the project budget on the basis that this asset is not due for replacement under business as usual and the requirements to set it up for dedicated testing are inherent to the project. However, it is recognised that this will provide additional asset life to the university, and so it is agreed that it is appropriate that the full cost of the new pipeline itself is not borne by the project, reducing the overall budget by £25,000. An element of leakage is present throughout any gas network and therefore transporters are obliged to undertake regular monitoring. Keele maintains a register of elements of the network which require particular observation, and this section of pipeline falls into this category. Currently the agreed Safety Case for the network under business as usual operation indicates a residual asset life of 14 years.		

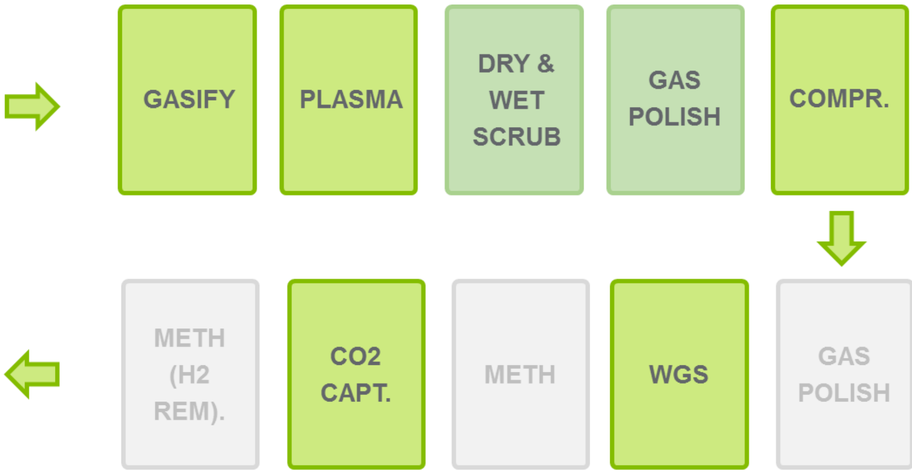
	However, in light of performance to date and in discussion with NGGD, NGN and the HSE it has been recognised that this element of the network would represent an uncertainty under hydrogen operation which would need to be factored into the Quantitative Risk Assessment. This uncertainty could adversely affect the QRA outcome. Given the wide range of factors which will need to be addressed for the first time in this project, it was agreed that to risk manage overall project delivery of the programme, this risk should be addressed such that it doesn't 'gate' the outcome for the wider network trial. However, this asset also provides a unique opportunity to undertake more dedicated and focused tests on this part of the network, including the existing transition from plastic to steel pipeline. This is particularly instructive as this is an old, in situ pipeline, with very limited experimental data available for such infrastructure. Furthermore BEIS identified that this provides a unique opportunity to undertake tightness testing with 100% hydrogen. It was therefore decided that this pipeline spur would be disconnected from the network, and the residual consumers at the end of this spur connected directly to Keele's G1 network. The existing pipeline asset will be disconnected, decommissioned, and reconfigured for direct connection to a dedicated supply and subsequent testing. The project budget is £80,000 for this work including £50,000 for the new pipeline itself. Although none of this work would be required at this stage if it weren't for the project, in recognition of the fact that it will deliver an element of asset life extension to Keele, it is agreed that only 50% of pipeline cost itself would be attributed to the project, reducing the overall budget by £25,000.
Attachments	

Project code	**NGGDGN03/1**	**Question Number**	**11**
Question date	**090916**	**Answer date**	**150909**
Submission section question relates to			
Topic			
Question	**Please can you provide more detail on:** **(i) The business case for biohydrogen as source** **(ii) The long-term cost of the production of biohydrogen compared to the cost of natural gas, given learnings over the last year and also allowing for different scenarios for gate fees.**		
Notes on question			
Answer	*(i) Business case for biohydrogen as source* The business case for bio-hydrogen builds on the case for the production of BioSNG. This has been developed and refined over the last 3 years providing the basis for the award of NIC funding under previous rounds of the competition. Key elements in the business case are: • Strategic: The delivery of low carbon gas to deliver non-disruptive heat to consumers using the UK's existing gas distribution asset and customers' existing heating systems. • Feedstock: Sufficient feedstock identified to deliver 100TWh per annum on a full potential basis by 2050. Sufficient waste is currently being exported deliver nearly 10TWh pa alone with nearly 4 times that currently being landfilled. • Technology: the production of a high quality syngas from waste derived material which is converted through the water gas shift and catalytic methanation to a fungible fuel. Being piloted with a commercially operating demonstration project underway and the first large scale plant planned for 2020/21. Similar pure biomass project operating and delivering gas to the grid in Sweden. • An overall cost base from waste feedstocks which has the prospect of being cost competitive with conventional fossil fuels. Existing support structures, particularly the RHI which explicitly support injection of biomethane into the grid to support the transition to that point.		

The numbers supporting the business case have been refined through the work of both NGGDGN01 and NGGDN02 as described below.

The business case for hydrogen is very similar, but with the following key differences:

- The process is substantially simplified. The most sensitive and complex catalytic reaction is the methanation stage which is no longer required, and the upstream gas polishing can also be simplified as shown schematically below (Full green processes remain, lighter green process simplified and light green processes removed). This both reduces capital cost and increases process resilience.



- Hydrogen has the potential to be more valuable than natural gas (as typically hydrogen is produced by processing natural gas), enabled by the development of wider markets such as fuel cells and vehicles. Longer term this provides valuable additional markets to drive the development of bio-hydrogen production.

(ii) The long-term cost of the production of biohydrogen compared to the cost of natural gas, given learnings over the last year and also allowing for different scenarios for gate fees.

The long term cost of production has been based on the work from NGGDGN01 and NGGDN02. This has informed:

(a) Process performance: Operation of the pilot plant has confirmed the thermodynamic and kinetic modelling of the process, underpinning the performance assumptions made, including greenhouse gas emissions.

(b) Capital costs: The overall costs of construction have remained broadly in line with those anticipated at the start of the project. The demonstration project has required the team to go to market for firm pricing. Other than the specific addition of CO_2 liquefaction process in order to demonstrate utilisation of CO_2 (such CO_2 savings have not been assumed here) there has been a 3.5% increase on the overall costs, primarily due to movements in the pound since Brexit.

	(c) Operational and gate fee assumptions: Figures for operational costs have been refined, with minor changes. There have been no changes to feedstock assumptions, with waste for the demo project at £65/te. Gatefees payable for RDF have risen from £72.50 +/- £7.50 to £85 +/-£5 between June 2014 to June 2016 (Lets Recycle). This is driven in part because landfill tax has now increased to £84.40/te such that total landfill costs are £100-£110/te. Export of RDF is expected to approach 4 million tonnes over the next year. Current projections for FOAK BioSNG production are £50/MWh falling to £35/MWh for a 315GWh plant or £21/MWh for a 665GWh larger plant over the period to 2030, recognising primarily reduced risk margins and hurdle rates. In assessing the financial performance for hydrogen production, conservative figures have been used: • Capital and operational costs for production have been maintained at the BioSNG levels, despite the process simplification described above. Beyond 2030, it has been assumed that costs fall at 0.5% per annum through incremental learning • Only the smaller scale of plant has been assumed. • Gatefees have been set substantially lower • Additional costs for hydrogen storage and connection to the grid have been included. These figures are provided in the set of assumptions in Appendix B.4 (p57) of the Hydeploy bid with hydrogen levelised costs shown in the table below. These are conservative figures, but a sensitivity analyses to capex and gate fee shows that whilst the bio hydrogen uncertainty has an impact on the overall savings (using the 20% blending case as an example, as per the 2050 column of table B.3.1), it does not fundamentally change the merit of hydrogen blending. In reality it would probably lead to different mixes of hydrogen sources.
Attachments	

Bio-hydrogen sensitivities	FOAK £/MWhr	2030 £/MWhr	2050 £/MWhr	NPV saving £M cum.
Baseline	77	52	46	8060
Capex +20%	86	58	51	7190
Capex -20%	67	46	41	8930
Gatefee £22.50	83	59	53	7042
Gatefee £52.50	70	45	40	9078

Tick if this answer has been provided verbally: ✓

Project code	**NGGDGN03/1**	**Question Number**	**12**
Question date	**26-09-16**	**Answer date**	**04-10-16**
Submission section question relates to			
Topic			
Question	**Can you compare the use of hydrogen to deliver decarbonised heat in relation to other future energy scenarios. For example, compared to district heating from municipal waste? How sensitive is the economic case for hydrogen to future market changes?**		
Notes on question			
Answer	The following is a commentary supporting the slides used in the bilateral meeting on 30/09/16 shown below. Various commentators have projected a range of future energy scenarios (six pathways to 2050 have been considered by the Department of Energy and Climate Change (DECC), the Committee on Climate Change (CCC), the Energy Technologies Institute (ETI), National Grid, the UK Energy Research Centre (UKERC) and Delta EE). Common to all is the fact that the size of the heat challenge is sufficiently large and diverse that there is no single solution. The most recent assessment by the Policy Exchange ('Too hot to handle' September 2016) recognises that successfully delivering low carbon heat requires solutions which are readily adoptable by customers. Compared with scenarios which place great weight on the adoption of heat pumps and district heating, they put forward a more balanced scenario; (a) improving building efficiency, (b) improving gas appliance efficiency, (c) increase low carbon/renewable gas delivery, (d) adoption alternative technologies, (heat pumps, and district heating). District heating undoubtedly has a role to play in the mix. The Policy Exchange report outlines that 1% of UK households are currently supplied via district heating with a realistic future potential of 10-15%. Element energy in its recent report shows that it is a good solution for areas of high population density, but even high uptake only covers <10% of UK $1km^2$		

	heat zones. Element energy suggests that EfW could contribute 3TWh to district heat demand. Hydrogen blending as shown by the HyDeploy work could provide up to 29TWh; against the Carbon Plan requirement of over 83TWh low carbon heat by 2030 it is clear that all solutions are required. 3TWh of waste derived heat would require 1-2 million tonnes of waste per annum depending on how the heat is delivered. Against current landfill and export levels equating to 17 million tonnes, this does not substantially affect the availability of waste for the proposed volumes of hydrogen from this source. Work by Poyry assessed the costs of heat delivered by district heating. The figures they determined for baseline gas generation, and heat pumps were broadly consistent with the figures given in the HyDeploy assessment £60 and £130/MWh respectively, compared with hydrogen at £107/MWh. Their view of DH with EfW was in excess of £200/MWh. The exact cost does depend on assumptions made about EfW, and in reality the figure may be somewhat lower than this. However, they assess conventional gas CHP solutions with DH at around £110/MWh, which is not a 'low carbon' solution, rather a more efficient use of gas; CO2 is still emitted. In this context, decarbonised hydrogen has a valuable and important role, particularly since it could also have a role in district heating schemes further decarbonising them. As recognised by the various reports, there are a number of challenges to overcome with regard to district heating schemes: capital cost of networks, disruption of network installation, disruption in households, limitations to individual customer choice, new build estates still need policy intervention, annual heat demand in benign climate, continuity of waste processing vs fluctuating local demand, forfeited power (EfW plant) and counterparty risks. It is recognised that some of these issues can be addressed by appropriate policy interventions, but others, particularly customer focused ones remain. Ultimately there is no doubt that there is a role for district heating to deliver carbon savings, but in parallel with solutions such as low carbon gas delivery which is non-disruptive for the customer and which valorises existing extensive infrastructure.
Attachments	

Q1: Heat context: Other Future Scenarios

- The size of the heat challenge means that there is no single solution
- Numerous studies developed showing different combinations of solutions
- "Too Hot to Handle" Policy Exchange 09/16

- Sets out a customer focused framework recognising the strategic role for gas, in light of over 80% of households being heated by gas
- Heat pumps & district heating are core 'Alternative Technologies'

Q1: Heat Networks & Energy from Waste

- Currently: 1% of UK households, Future: 10-15% (Too Hot to Handle)
- Good for populations of high density, but even high uptake covers <10% of UK 1km^2 heat zones
- Opportunity to deliver 3TWh pa of heat from EfW facilities via district heating systems (Element Energy)


frontier
Imperial College London
Research on district heating and local approaches to heat decarbonisation
A study for the Committee on Climate Change
Main Report
element energy

Plymouth EfW CHP January 2016

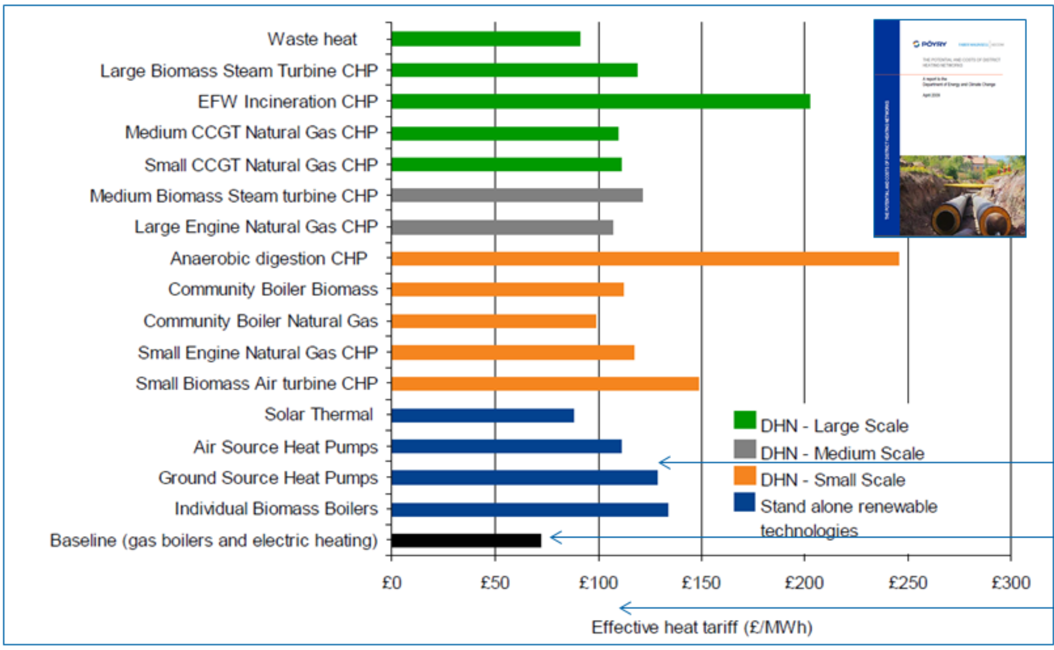
Under an energy services agreement with the Ministry of Defence, MVV Devonport will supply 24MW of electricity and steam to the adjacent Naval Dockyard, the largest naval base in Western Europe. Paul Carey, managing director of MVV Environment Devonport, said plans to develop a local district heating scheme for residents living close to the site were again "under review". The strategy was previously thought to have been scrapped, following a feasibility study with Plymouth city council which found the size of the heating scheme would make it impracticable.

- Challenges to overcome

♦ Capital cost of networks ♦ Disruption of networks ♦ Disruption in households ♦ Customer choice ♦ New build estates need policy intervention ♦ Annual heat demand in benign climate ♦ Continuity of waste processing ♦ Forfeited power (EFW plant) ♦ Counterparty risk

- Heat Networks have a role, but alongside existing infrastructure solutions

District Heating Cost Comparisons



Costs consistent with bid data

EfW DH considered expensive

Nat gas DH still emits CO_2

Bid Figures

Heat pump £130/MWh

Baseline £60/MWh

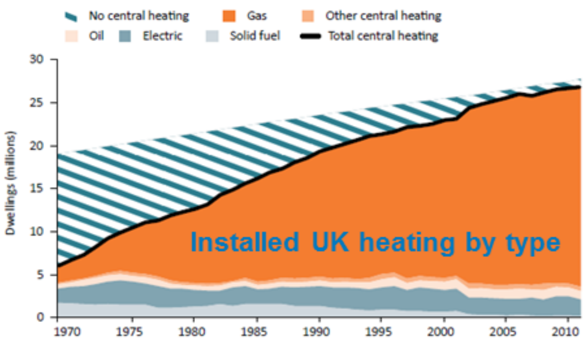
Hydrogen £107/MWh

UK GAS DISTRIBUTION

'Potential and costs of district heating networks', Poyry, Aecom, Faber Maunsell (2009)

Q1: How sensitive is the economic case for hydrogen to future market changes?

- Fundamental *costs* of decarbonisation by hydrogen are not changed even with elements of heat pumps and district heating networks
- Some impact on *level* of contribution if gas demand reduces further, noting other solutions still likely to include elements of gas consumption
- Using existing gas infrastructure is the most customer focused solution
- Barriers to deployment far lower than solution requiring new infrastructure



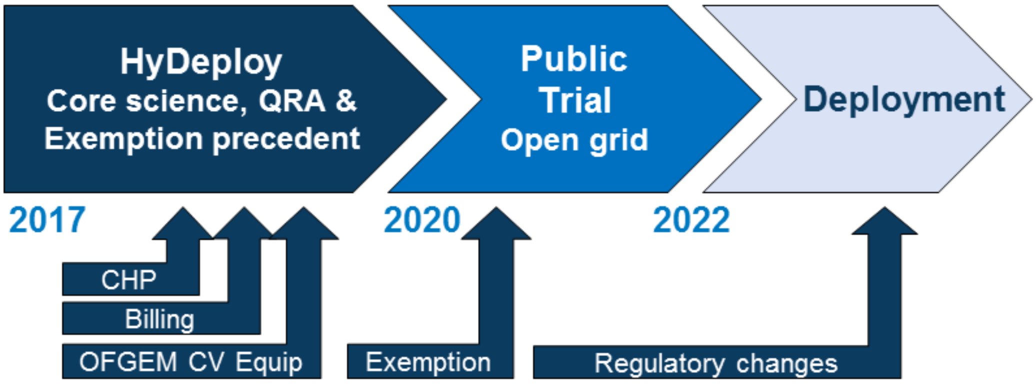
UK GAS DISTRIBUTION

Tick if this answer has been provided verbally: ✓

Project code	**NGGDGN03/1**	**Question Number**	**13**
Question date	**26-09-16**	**Answer date**	**04-10-16**
Submission section question relates to			
Topic			
Question	**If the project is successfully completed, what are the next steps? Can you provide a bit more detail on your plans for the public network trial?**		
Notes on question			
Answer	The following is a commentary supporting the slides used in the bilateral meeting on 30/09/16 shown below. The HyDeploy project is the first UK deployment of a hydrogen – natural gas blend onto the distribution network. As described in the bid, and supported by experts such as the HSE and DNV-GL, this first trial will be on a closed, private network in order to risk manage project delivery and potentially enable more ambitious levels of blend that would otherwise be achievable than executing the first trial on a public network. However, a public network trial as always been envisaged as the important next step towards widespread deployment. The customer engagement plan, safety case and application for exemption for that public network trial will build on the wide ranging foundational work from the HyDeploy project at Keele, as shown in the Infographic developed in response to question 7. It will also draw on wider parallel work in the industry relating to other gas users such as CHP facilities. Ideally that public trial will also build on work related to revised billing methodologies and OFGEM 'Directed' compositional measurement equipment. (Whilst a public trial could use the same approaches as proposed at Keele, it would be strongly preferable to execute more enduring strategies, representative of future deployment) It is expected that this public trial will secure an individual exemption through the same model as the Keele project. However, as with the oxygen exemption for anaerobic digestion plants, this should pave the way for a		

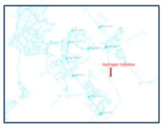
	'class exemption' and ideally enduring regulatory changes. The detailed public trial will be defined as part of the HyDeploy programme (Work Package 14). This includes a scientific gap analysis undertaken at that point in the project. However, the key aspects are detailed below **Site Selection:** the site will be selected to be statistically representative of the GB distribution network. This will be undertaken building on the methodologies used in the opening up the gas networks project. It will be an 'open' network, accommodating gas flowing in from various sources, with the implications this will have for varying hydrogen blend compositions over time. Suitability for locating the hydrogen production and injection facilities will also be an important criterion. NGN and NGGD have already undertaken some early feasibility assessments of a potential site, in particular to model the flows of hydrogen in an open network under a variety of conditions. It also meets the criteria for local stakeholder support regarding location of production and injection equipment. However, this site will be evaluated alongside other sites, particularly with regard to statistical representativeness of the GB network. **Equipment:** The production and injection facilities will be re-used, as well as monitoring equipment. However, it is anticipated that the public trial would provide the opportunity to deploy OFGEM Directed Composition measurement equipment, rather than relying on a declared CV basis. **Trial Length:** Minimum of 18 months to 2 years, although ideally it would be longer than this, although this would depend on specifics of site location, and whether there is an enduring support regime for low carbon heat by that stage. **Customer Engagement:** This would be based on the HyDeploy learning, executed in a truly public environment. This would be serviced by the GDNs, rather than in conjunction with the university as is the case at Keele **Experimental:** There would still be a need to undertake monitoring both on the network and, where possible, on appliances in private households, similar to the Oban project. It is important to understand in detail any differences between the work at Keele and on a public network. However, it is expected that this will be significantly less intensive that in the HyDeploy project due to the body of work which will already be developed. In parallel, on the basis of successfully securing funding for the SEND programme, Keele University anticipates being able to support hydrogen training for gas fitters, as part of its activities to support businesses.
Attachments	

Q2: If the project is successfully completed, what are the next steps?



- Public trial
  - Definition a key element of the HyDeploy programme
  - Early feasibility assessment of sites already underway, with local stakeholder support

Q2: Can you provide a bit more detail on your plans for the public network trial?



- Site selection
  - Statistically representative of the GB gas distribution network
  - ‘Open’ network, accommodating gas flowing from various sources
  - Location suitable for operation of hydrogen production facilities

- Equipment
  - Re-use the production and Injection facilities from HyDeploy
  - Install new OFGEM-Directed CV measurement equipment

- Trial Length
  - Minimum of 18 months to 2 years
  - Ideally able to continue long term, subject to low carbon heat regime

- Customer Engagement
  - Based on the learning from HyDeploy, truly ‘public’ engagement
  - Serviced by the local GDN

- Experimental
  - A monitored experimental programme to secure long term operational data on private households, but less intensive than HyDeploy

Tick if this answer has been provided verbally: ✓

Project code	**NGGDGN03/1**	**Question Number**	**14**
Question date	**26-09-16**	**Answer date**	**04-10-16**
Submission section question relates to			
Topic			
Question	**How sensitive are the costs and benefits to changes in the future price of natural gas?**		
Notes on question			
Answer	The following is a commentary supporting the slides used in the bilateral meeting on 30/09/16 shown below. The price of natural gas flows into the assessment primarily for the tranche of Hydrogen generated using a Steam Methane Reformation unit with associated CCS. In its Future Energy Scenarios, National Grid has forward gas curves for a high and low cases as well as the central. The high case is between 130-140% of the central case and the low is 82-88%, thus giving a wide spread for the purposes of reviewing sensitivity. As shown in the tables below, this does have an impact on the quantum of the savings, for example a central case of £8,060m savings varying from £7,084m to £8,502m with high and low gas prices respectively. However this does not change the fundamental conclusion. It should also be noted that higher gas prices would have some impact on electricity prices (dispatchable gas generation being likely to contribute to annual grid generation in order to accommodate fluctuating wind and solar). Therefore the cost of the heat pump reference case will change and thus offset an element of the change shown above.		
Attachments			

Q3: How sensitive are costs and benefits to changes in the future price of natural gas?

Scenarios

Wholesale gas (£/MWh)	2015	2020	2030	2040	*2050*	Range
High Case	14.6	20.6	27.3	27.3	*27.3*	130-140%
Base Case	14.6	15.5	19.4	20.4	*20.4*	Base
Low Case	14.6	12.7	17.0	17.0	*17.0*	82%-88%

Results

Cumulative NPV, GB Values, 20% Blend	To 2030 £million	To 2040 £million	To 2050 £million
Central	1,897	6,025	8,060
High Gas	1,885	5,503	7,084
Low Gas	1,901	6,242	8,502

Cumulative NPV, GB Values, 10% Blend	To 2030 £million	To 2040 £million	To 2050 £million
Central	855	2,548	3,269
High Gas	849	2,286	2,780
Low Gas	857	2,656	3,489

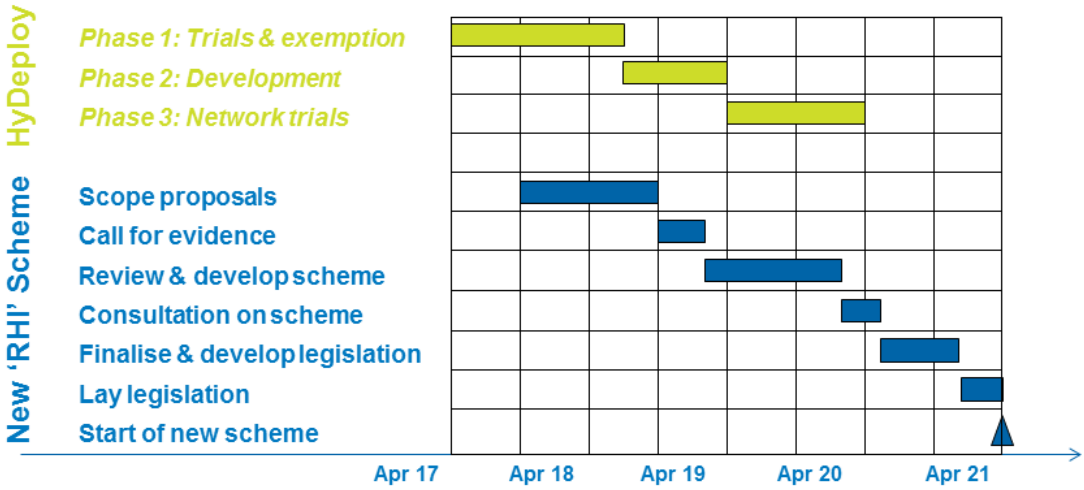
- FES scenarios consider a wide range from the base case
- Whilst there is an impact on the quantum of saving, it doesn't change the fundamental conclusion
- Higher gas prices would have some impact on electricity price & therefore cost of heat pumps offsetting some of change

Tick if this answer has been provided verbally: ✓

Project code	**NGGDGN03/1**	**Question Number**	**15**
Question date	**26-09-16**	**Answer date**	**04-10-16**
Submission section question relates to			
Topic			
Question	**How might the funding and successful completion of this project form the debate on the future of the Renewable Heat Incentive?**		
Notes on question			
Answer	The following is a commentary supporting the slides used in the bilateral meeting on 30/09/16 shown below. The Comprehensive Spending review confirmed the funding of the RHI scheme until March 2021. The current regime is subject to a range of modifications within the existing framework due to be implemented in April 2017. However, as shown by the recent consultation, these interim changes remain within the context of the UK's renewable Energy commitments and based on the suite of technologies already included within the RHI scheme. There is universal agreement that addressing the carbon emissions within the heating sector will require ongoing policy intervention to meet our carbon budget obligations. However, the objective is expected to move from a renewables focus to a carbon focus. Therefore there will need to be an appropriately revised support regime post March 2021, in absence of implementation of a wider overhaul of carbon pricing in general. This means that the scope of such an incentive is expected to be broader than the technologies currently supported. Particularly with the move of DECC back within BEIS, it is likely that this could entail more a 'infrastructural view' where the valuable role of existing assets, such as the gas network, are considered carefully. In order for any government department to evaluate new policy it must be able to undertake an Impact Assessment to quantify the potential of particular solutions. The key outcome of the HyDeploy project is to establish firmly the level of hydrogen-natural gas blending that is feasible and acceptable to the HSE.		

	Understanding the quantum of the phenomena is fundamental to any impact assessment. HyDeploy will also provide an evidence base for the costs, particularly related to the network and its management that such an approach would entail. As discussed in the bid, other regulatory barriers will need to be addressed, such as those related to Directed Compositional measurements and billing regimes. These need to be understood when evaluating a new regime. Whilst not core to the blended hydrogen approach, this project will also provide valuable technical evidence regarding the feasibility of 100% conversion, to inform the wider hydrogen debate and the role it could provide more widely. Any new scheme must follow seamlessly from the current RHI regime, otherwise a hiatus will jeopardise ability to meet the 5th carbon budget. As shown in the figure below, against a realistic development programme for implementation of new policy, the HyDeploy programme provides timely evidence.
Attachments	

Q4: Appropriate timing to inform debate



Based on typical timings for scheme development