A CONCEPTUAL DESIGN OF A MOBILE SHALE GAS PROCESSING FACILITY

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ABSTRACT

Natural gas is a key element of the UK's energy supply, comprising 35% in 2015[1]. While consumption of natural gas has almost doubled since 1975, actual production in the UK has declined in 2000. This led to a significant increase in gas importation. The UK is believed to have a potential of up to 1300 TCF of shale gas[2], of this, around 10% is believed to be recoverable. This would mean around 50 years gas supply for the UK and offering the potential to a reduced dependence on imported natural gas.

Exploration and appraisal phases of a shale gas well production test require flaring to collect well flow data. This increases environmental damage from greenhouse gas emissions of flared methane and CO_2 emissions, and prevents operators achieving their social license to operate. To facilitate a long-term production test, a shale gas operator needs a "demand" for the gas. The most obvious UK demand is the Gas Distribution Networks (GDNs) and National Transmission System (NTS).

DNV GL has undertaken a project to develop a concept design for a self-contained and transportable gas processing facility. The purpose of the facility is to process recovered gas, during the appraisal stage on a small-scale "well-to-well" development, to meet gas quality requirements to deliver the gas to the NTS and/or GDNs.

If the mobile gas processing facility concept is further developed and proved, valuable natural gas resources could be recovered with minimal environmental impact.

KEYWORDS: Shale Gas, Shale Gas Development, Gas Processing, Mobile Plant, National Transmission System, Gas Distribution Network, Social License to Operate

1 INTRODUCTION

1.1 Background

Natural gas is a key part of the UK energy supply. Total UK annual consumption of natural gas increased to 35% of all fuels consumed in 2015, while the gas production has declined by 60% over the last 15 years to 2015. This caused significant increases in gas being imported, which have more than doubled since 2005 (BEIS, 2016). Import levels are expected to increase by 70% by 2030 (Earp, 2016).

The UK has also seen a large reduction in CO_2 emissions of 32% from 1990 (BEIS, 2015), driven by the change in fuel mix for electricity generation. However, the government has set an even tighter emission reduction of 80% of the 1990 levels by 2050, which means that more challenging measures are needed to achieve the targets (Committee on Climate Change, 2017).

The government is facing the trilemma of energy – (1) affordability of energy, (2) carbon reduction, and (3) energy security. It is becoming increasingly important for the UK to generate its own energy, but it will take years for renewable sources to be fully developed. Therefore, gas generation will play a vital

[1] Source: http://www.energy-uk.org.uk/energy-industry/electricity-generation.html
[2] This is based on the estimate of the British Geological Survey of the Bowland Shale alone.

role for many years to come and the opportunity of developing the indigenous shale gas offers the potential to assist in solving the energy trilemma.

1.1.1 Shale gas and the UK

Shale gas is a natural gas (predominantly methane) found in shale rock formations, and a process called hydraulic fracturing[3] is used to extract the gas. Estimates of UK shale gas are significant (Figure 1-1). There is potentially up to 1300 TCF of shale gas in Bowland Shale alone, with around 10-20% of this believed to be recoverable (U.S. EIA/ARI, 2015).

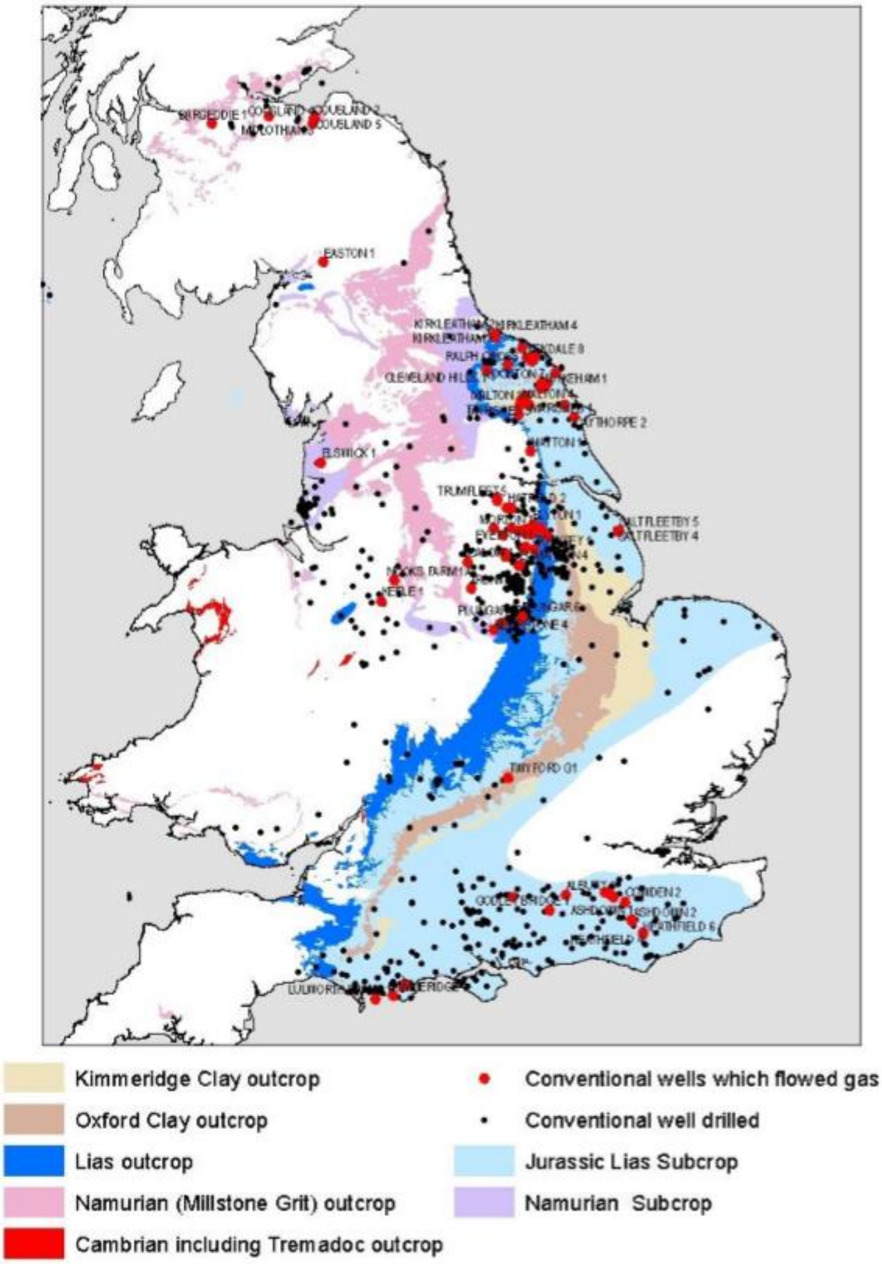

Figure 1-1. Prospective gas shales in UK (DECC, 2014)

Shale gas could replace a portion of gas imports, thereby improving the UK energy security. It also plays an important part in bridging the gap between the current system and any future low carbon

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3 Hydraulic fracturing is a technique used to extract shale gas, which uses water, pumped at high pressure into the rock to create narrow fractures to allow the gas to flow into the well bore to be captured

technologies. If well regulated, the overall carbon footprint from shale gas in UK could be lower than imported LNG, and much lower than coal, provided methane emissions during production are minimised (David MacKay, 2013).

1.1.2 Shale Gas Development in the UK

Shale gas development in the UK is still in its infancy with limited exploratory drilling and appraisal activity carried out so far. During the exploration and appraisal phases, a well needs to be flared to collect well data. This increases environmental concern due to the methane and CO_2 emissions when the gas is burnt.

Flaring of gas and other environmental concerns, such as potential drinking water contamination, has led to strong opposition by the public. Even though the UK government are keen to seize opportunities offered by its shale gas resources by offering licenses to operators, the major obstacle is the operator's "social license to operate", or the level of acceptance by local communities and other stakeholders.

Given the large uncertainties, combined with public concern, and the regulation and consenting required in the UK, the development of a full-scale shale gas "revolution" in the UK is not considered to be imminent.

Shale gas operators and the government need to demonstrate the safe operation and minimum environmental footprint of shale gas development. The most likely approach in the near-future will be the approval of several wells for testing, followed by pilot scale facilities. These "early production facilities" should, over time, help reduce public concern and provide greater economic certainty for operators. During this phase, operators need a "demand" for the gas. The most obvious UK demand is the Gas Distribution Networks (GDNs) and National Transmission System (NTS).

Gas distribution operators are now considering the compatibility of varied sources of gas to the supply network with work ongoing with IGEM, ENA and stakeholder partners to update the Gas Safety Management Regulations following the SGN NIC Oban project. National Grid has instigated the project CLoCC (Project CLoCC, 2017). CLoCC intends to consider all types of connection to the system and to produce 'off-the-shelf' standardised designs for connections irrespective of the size of connection, or type of gas. Cadent Gas has also partnered with DNV GL to investigate a "proof-of-concept" for new approaches to enable entry of all compliant gases, which includes unconventional gases from shale, to the gas distribution networks (Future Billing Method, 2017).

With the recent innovation projects, it is likely that shale gas can be injected to the NTS and/or GDNs, so long as it meets the gas quality requirements. The prospect of a small-scale facility to process shale gas to meet the entry requirements will therefore be highly beneficial.

1.2 Objectives

The project aim is to investigate the feasibility of a mobile gas processing facility to process recovered shale gas on a small-scale "well-to-well" development and deliver the gas to the NTS and/or local GDNs.

Key considerations for the design of the mobile processing facility are shown in Figure 1-2:

1. Process recovered gas during the production testing on a small-scale well-to-well development

2. Deliver processed gas to the distribution networks and meet the pipeline requirements

3. Develop a self-contained, transportable gas processing facility on the back of trucks

4. Meet the road transport specification for size and weight

Figure 1-2. Project Objectives

1.3 Study Boundaries and Overall Assumptions

Boundaries for the study include facilities from the well flow-line up to the export gas pipeline. The produced water and condensate storage vessels are also included.

A simplified block flow diagram of processing is presented in Figure 1-3 with the study boundaries highlighted (dashed line).

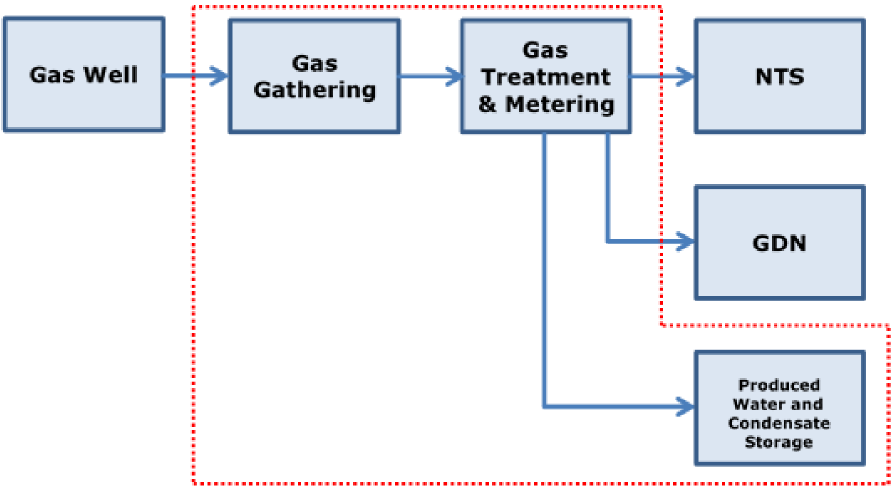

Figure 1-3. Simplified block flow diagram showing the study boundaries

This project only considered the period following hydraulic fracturing. It is assumed that the well has already been cleaned up before large volumes of the gas can flow to the surface. The gas recovered from the fractured wells will be directed to the mobile facility.

The assumptions used to develop the design for the facility are described in Appendix A.

2 CONCEPT DEVELOPMENT

This section describes the various stages of the mobile gas processing facility. The justification of the equipment considered for each stage of the facility are outlined in Appendix B.

2.1 Process Boundaries

The main gas processing requirements is summarised in the block flow diagram shown in Figure 2-1.

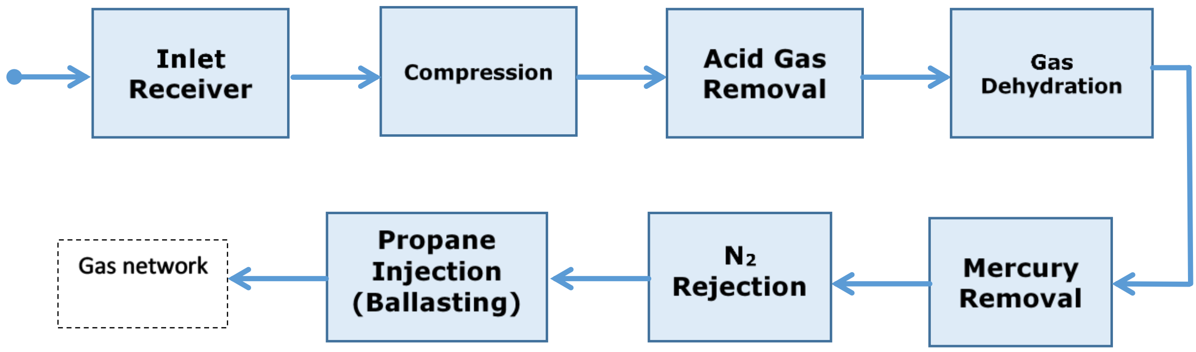

Figure 2-1. Gas treatment facility diagram

The raw gas may not meet the NTS pipeline specifications. Gas condensates, impurities and inerts, such as nitrogen, mercury, or hydrogen sulphide need to be removed by the gas processing facility.

2.1.1 Gas Gathering and Treatment

During the hook-up phase, reusable flowlines (flexible pipe) will be connected to the well flow-line to deliver gas from the well to the mobile processing facility.

Gas is then treated to meet the entry specifications. Gas treatment design concepts used for the mobile processing facility were evaluated and are described in Appendix B.

2.1.2 Export Gas Pipeline

Installing fixed pipelines would be uneconomical, as the facility is anticipated to be transported from one well location to another once the wells have been exhausted. Reusable flowlines will be used to attach the mobile facility through bespoke fitting to live distribution pipelines.

2.2 Utilities

The produced water recovered during production will be treated initially and stored on-site with periodic removal. Produced water will be collected by trucks and delivered to a water treatment facility off-site.

A fraction of the gas produced is sent to a generator set (genset) to power the facility. The requirement for a genset depends on the location of the facility. If it is located in a remote area, it may be difficult to get it to connect to the grid; so, an uninterruptible power supply (UPS) is required for the control system and a genset will still be needed.

3 NOTIONAL LAYOUT OF THE FACILITY

The units required to process the shale gas depend entirely on the fluid composition and the pipeline requirements.

Conceptually, the equipment installed on the back of the trucks can either be fixed or skid-mounted. Table 3-1 shows a notional layout of the gas processing facility. Each piece of equipment is designed for a maximum rate of 1 MMscfd and sized to fit on the back of the trucks. The equipment with rotating parts (i.e. compressors and air coolers) are separated from the static equipment, due to the concern on the impact of vibration to the contactor beds.

The road transport specification for size and gross weight are described in more detail in Appendix C.

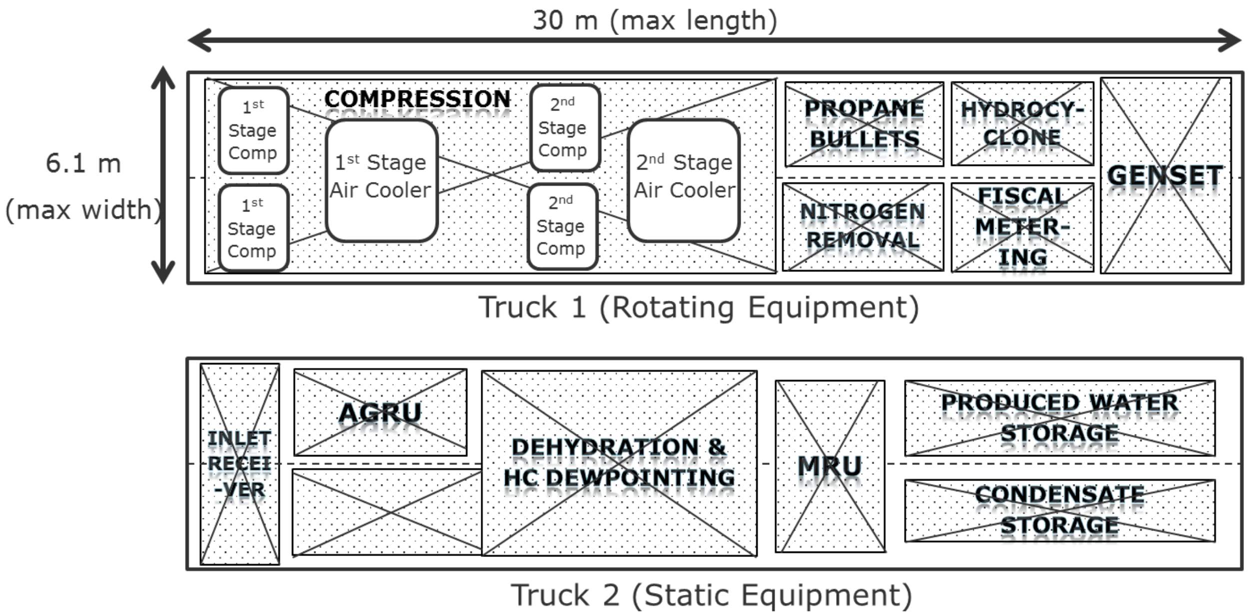

Figure 3-1. Hypothetical mobile gas processing facility layout.

4 CONCLUSIONS

The UK is highly reliant on imported natural gas, but if shale gas resources are exploited, it could provide the country with gas supply for around 50 years and lead to significant economic benefits. Shale gas development is still in its infancy in the UK and drilling and testing more wells are necessary to prove that shale gas development is technically and economically viable.

The proposed gas processing facility design should assist operators to achieve their social licenses to operate. The processing facility is temporary and it reduces the footprint to minimum. This gives assurance to the local communities that, once the wells have been exhausted and production period is finished, all equipment are removed and the area is restored to its original state. This conceptual design should thus help make shale gas in the UK a reality.

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6 ACKNOWLEDGEMENTS

This project was supported by DNV GL. I am thankful to my colleagues who provided their expert advice which greatly assisted in the delivery of the project. My thanks to Graham Dawe and Mark Fisher, who were tremendous help to make this project happen. Also to my family for their cheer and support. Finally, I thank God Almighty for His wisdom to accomplish the project.

APPENDIX A – BASIS OF DESIGN

The following sections describe in detail the assumptions that have been used to develop the conceptual design of the gas processing facility.

Reservoir Conditions and Fluid Compositions

Although a few shale wells have already been drilled in the UK, none of these have been fully appraised or produced into the gas grid. Hence there is very limited data available. For this study, the following assumptions given in Table 1 and Table 2 were assumed for reservoir and wellhead conditions and fluid compositions, respectively.

Table 1. Reservoir Conditions[4]

Reservoir Conditions	Value
Initial Pressure	200 barg
Initial temperature	93°C
Depth	2,000 – 3,000 m
Rock Porosity	< 10%
Permeability	0.01 – 0.14 mD
Wellhead Conditions	
Maximum Wellhead Pressure	30 barg
Minimum Wellhead Pressure	5 barg
Maximum Wellhead Temperature	53°C
Minimum Wellhead Temperature	40°C

Table 2. Well Fluid Compositions (on a dry basis)[5]

Component	Sample A [6] (mole %)	Sample B (mole %)	Sample C (mole %)
Nitrogen	1.60	35.9	14.3
Carbon Dioxide	0.37	0	3.3
Methane	96.41	57.3	77.5
Ethane	1.30	4.9	4
Propane	0.18	1.9	0.9
i-Butane	0.06	-	-
n-Butane	0.03	-	-
i-Pentane	0.02	-	-
n-Pentane	-	-	-
C6+	0.03	-	-
Oxygen	-	-	-

[4] Data provided are assumed wellhead conditions during testing of a single gas well. Wellhead temperature estimates based on "Production Optimization in Shale Gas Reservoirs" paper by B. Knudsen, NTNU, June 2010

[5] Sample B and C are fluid compositions from two US shale gas wells with one sample having high N_2 and low CH_4 contents (Sample B) and the other with high CO_2 content (Sample C). Data is extracted from the Oil & Gas Journal.

[6] The fluid composition of Sample A is an initial UK Shale Gas well test data provided by CNG Services Ltd.

Component	Sample A [6] (mole %)	Sample B (mole %)	Sample C (mole %)
Hydrogen	-	-	-
H_2S	20 ppm	-	-
Mercury	100 ug/Sm^3	-	-
Helium	-	-	-

Sample A has a CV around 37.7 MJ m^{-3}, which is lower than the prevailing flow weighted average CV of around 39.0-39.5 MJ m^{-3} for UK domestic gas. Conversely, shale gas in the US (samples B and C) has low CV values, typically around 26.6-33.8 MJ m^{-3}.

Fracking fluid/initial flowback water has not been considered in this study (assuming most of it has already been separated prior to well testing); produced water from reservoir has been assumed to be composed of free water and saturated water only. Well fluid was assumed to be saturated wet.

Design Capacity and Analysis Period

Early phase well production was assumed to last for 6 months, but could be extended up to a period of 24 months, with a constant well gas flow rate of 1 MMscfd.

Network Entry Requirements

Different natural gas grids have their own set of gas quality specifications, but before gas can be injected, it needs to be upgraded to be suitable for grid injection. The specifications are summarised below for the NTS (see Table 3) and GDN (see Table 4).

Table 3. Gas quality requirement for NTS

Pressure	Max	70-94 barg (depending on location)[7]
Temperature	Min	1 °C
	Max	38 °C
Hydrocarbon dewpoint	Max	-2°C at any pressure up to 85 barg
Water dewpoint	Max	-10 °C at 85 barg
Wobbe Index	Min	47.2 MJ m^{-3}
	Max	51.41 MJ m^{-3}
Calorific Value (CV)[8]	Min	36.9 MJ m^{-3}
	Max	42.3 MJ m^{-3}
Total Sulphur	Max	50 mg m^{-3}
Hydrogen Sulphide	Max	5 mg m^{-3}
Carbon Dioxide	Max	2.5 % mol
Oxygen	Max	0.001 % mol
Hydrogen	Max	0.1% mol
Inerts	Max	7 % mol
Organo-halides	Max	1.5 mg m^{-3}

[7] Pressure depends on back pressure and delivery point in the entry facility
[8] This is subject to gas entry location and volumes; a target for the CV may be set within this range.

Incomplete combustion factor (ICF)	Max	0.48
Soot Index (SI)	Max	0.6
Radioactivity	Max	5 Bq g^{-1}

Table 4. Typical Gas quality requirement for GDN

Pressure	Max	34-70 barg (depending on location)
Temperature	Min	1 °C
	Max	38 °C
Hydrocarbon dewpoint	Max	-2°C at any pressure up to 85 barg
Water dewpoint	Max	-10 °C at 85 barg
Wobbe Index	Min	47.2 MJ m^{-3}
	Max	51.41 MJ m^{-3}
Calorific Value (CV)	Min	36.9 MJ m^{-3}
	Max	42.3 MJ m^{-3}
Total Sulphur	Max	50 mg m^{-3}
Hydrogen Sulphide	Max	5 mg m^{-3}
Carbon Dioxide	Max	2.5 % mol
Oxygen	Max	0.001% mol
Hydrogen	Max	0.1% mol
Inerts	Max	7 % mol
Organo-halides	Max	1.5 % mol
Incomplete combustion factor (ICF)	Max	0.48
Soot Index (SI)	Max	0.6

APPENDIX B – EVALUATION OF VARIOUS DEVELOPMENT CONCEPTS

This section describes the various development options considered for the mobile gas processing facility and assumptions used to determine its feasibility.

Potential options will be evaluated based on the key requirements set. The data outlined below in Table 5 are used to determine the requirements for the processing plant.

Table 5. Key specifications for the shale gas stream (base case)

Parameter	**Raw Gas**	**Sales Gas Out Transmission Spec. (GDN, NTS)**
Flowrate (MMscfd)	1	1
Pressure (barg)	5 - 30	34, 74
Temperature (°C)	30 (Summer), 5 (Winter)	1 (Min) to 38 (Max)
Hydrocarbon Dewpoint (°C)	0.51 (cricondentherm)	-2 at any pressure up to 85 barg
Water Dewpoint (°C)	Saturated	90
Calorific Value (MJ m^{-3})	37.22	36.9(Min), 42.3(Max)
Wobbe Index (MJ m^{-3})	49.03	47.2 (Min), 51.41 (Max)
Component	Sample A (mol %) Wet (@ 40°C WHT)	Sales (mol %)
Nitrogen	1.58	Total Inerts 7%
H_2O	1.24	
Carbon Dioxide	0.37	2.5
Methane	95.21	-
Ethane	1.28	-
Propane	0.18	-
i-Butane	0.06	-
n-Butane	0.03	-
i-Pentane	0.02	-
n-Pentane	-	-
C6+	0.03	-
H_2S	20 ppm	3.8 ppm
Mercury	100 ug/Sm^3	10 ug/Sm^3

Inlet Receiver

An inlet vessel will receive multiphase flow from the well to separate the liquid from the gas stream and other particulate matter. Initial volumes of liquid should be removed to reduce sizing of equipment downstream. A vertical pressure vessel will be used to reduce space occupied on the back of the truck.

Compression

It is assumed that fluid coming from a single wellhead has low pressure, and therefore needs compression to achieve grid entry pressures of 34 and 74 barg. Processed gas can either be subjected to:

- Full compression in the inlet to the gas treatment (after inlet receiver) using multi-stage compression with inter-stage cooling; or
- An initial intermediate compression of gas through to the gas treatment units, and compression to transmission pipeline pressure (after gas treatment).

Full compression of gas prior to entering the gas treatment units was selected for the study. It is beneficial to the dehydration unit downstream to perform compression and cooling upstream, as this will reduce water content in the gas stream and hence reduce the water removal requirement of the dehydration equipment. The inlet pressure to the dehydration unit should be above 34 barg for the efficient removal of water.

Full compression will be achieved using multistage centrifugal compressors, while inter-stage cooling will be achieved using air coolers.

Acid Gas Removal

Zinc oxide fixed bed has been selected for the acid gas removal unit (AGRU). It has a number of advantages over the other identified processes (e.g. absorption, low temperature/cryogenic, membrane, and scavengers). It does not require the use of liquid desiccant to perform H_2S removal, which eliminates the requirement of additional equipment for liquid inventory. It is also a widely-used technology especially with its high selectivity for H_2S and its applicability to treat gas streams with low levels of H_2S. The process is also advantageous as it can be used with a wet or dry gas stream.

The system will consist of an adsorbent bed on a 1 x 100% configuration. In order to increase the robustness of the process and to increase the level of saturation prior to bed change-out, which occurs every 6-12 months, space for a second vessel will be included.

Water Removal / Gas Dehydration

ADAPT© technology, which is based on solid-bed adsorption technology using silica gel as the adsorbent media, will be used for hydrocarbon dewpointing whilst removing the remaining water content in the gas stream. The main advantage of this solid-bed dehydration process over glycol dehydration is the use of solid, instead of liquid desiccant which also eliminates space requirement of additional liquid storage and eliminates entrainment and foaming issues. ADAPT also does not require the use of rotating machinery and has low pressure drop across the bed eliminating the need for recompression and making it easier to maintain.

A minimum of two towers, one for adsorption and another for regeneration, will be required. The towers will have internal insulation on them to avoid heating and cooling of vessel wall.

Bed regeneration will be achieved by passing feed gas, which is normally 10% of the total feed flow, through the regeneration heater (maximum outlet temperature of 275^{o}C), the bed to be regenerated, the regeneration cooler (outlet temperature of 35^{o}C) and the condensate knockout pot.

Mercury Removal

Metallic sulphide bed process has been selected for the mercury removal unit (MRU). It offers a number of advantages over the other solid bed processes (e.g. sulphur impregnated activated carbon, solid-supported ionic liquids and silver impregnated molecular sieves) such as - (1) it can be placed at upstream locations as it is more resistant to liquid carryover, (2) it is a widely-used technology which can treat both wet and dry gas streams, and (3) although it is non-regenerable it can still be handled in an environmentally-friendly way by selling it to specialist smelters to be re-used.

Typically 2 x 100% mercury trains is recommended, but in this instance only a 1 x 100% mercury train will be used; a mercury train on standby is not included since the plant will only be operating for a short period of time.

Nitrogen Rejection

Molecular Gate technology, which makes use of pressure swing adsorption technique, has been selected for the study as it removes nitrogen from the gas stream and at the same time reduces CO_2 to less than 2.5 mol % in a cost-effective manner, especially for streams with small gas feed rates. The technology can handle process flowrates which range from 0.5 MMscfd up to 50 MMscfd or even greater. It also does not require any liquid desiccants, making it preferable over absorption and cryogenic separation.

The unit will be placed upstream of the Propane Injection unit as heavier hydrocarbons, such as propane and C4+, have high affinity to the adsorbent material and will be removed along with the nitrogen and carbon dioxide into the tail gas. The system will consist of two vessels with the molecular sieve (fixed bed) adsorbent (titanium silicate) to create a continuous process and rapid cycles between adsorption and regeneration. The tail gas (N_2, CO_2, some methane and other hydrocarbons) will be directed to a single gas-engine drive genset to burn the tail gas.

The process operates by "swinging" the pressure from the high feed pressure where the N_2 and CO_2 are adsorbed on fixed adsorbent beds to a lower regeneration pressure. At this lower pressure, the affinity between the adsorbent and the N_2 and CO_2 is lower causing them to become free from the adsorbent and removed as tail gas; a small methane stream (typically 20% of the of the feed flowrate) is then used to purge the bed following this. Multiple beds are used to create a continuous process and rapid cycles between adsorption and regeneration helps minimise the adsorbent inventory.

Propane Injection

In order to enrich the calorific value of the natural gas stream and to meet grid specification for flow weighted average CV, propane addition by blending has been assessed.

The amount of propane to be injected to the treated gas depends on its composition and this may vary from well to well. It will be assumed that the amount required for injection will be much less than the amounts required for some of the large gas processing facilities. A propane bullet (or cylinder) and a backup bullet will be placed on a rack and will be put on the back of the truck.

APPENDIX C – VEHICLE / TRAILER LOAD LIMITS

One of the factors to be looked at in this study is the vehicle weight and dimension limits in the UK roads. This is a crucial aspect in the feasibility assessment to determine whether the facility can be transported from one well site to another.

In the UK, the maximum permitted gross weight of a semi-trailer truck is 44,000 kg (97,000 lb) and any other vehicle heavier than this, but with indivisible loads, is permitted but is required to display a Special Type General Order (STGO) plate, travel at an authorised route and have an escort.

These provisions in UK roads concerning the width, height, length and weight of vehicles, are regulated and are under Part 2 of the Road Traffic Act (Department of Transport, 2003). Table 6 summarises the maximum allowable limits in the UK roads. It should be noted that notifications for abnormal indivisible loads are required for these, depending on the various categories (see Table 7).

Table 6. Maximum allowable load and dimension limits on UK roads

Gross Weight	150,000 kgs (147.63 tonnes)
Width	6.1 metres (20’)
Length	30 metres (98’ 5”)

Note: The UK has no legal height limit, but most road networks can accommodate trucks up to a height of 4.9 m[9].

[9] http://www.hse.gov.uk/workplacetransport/vehicles.htm

Table 7. Notification requirement for various truck load and dimensions

	Action Required
Gross Weight	
Gross weight or axle weights exceeding Construction and Use Regulation or Authorised Weight limits up to 80,000 kgs (78.74 tonnes)	Two (2) clear days' notice with indemnity to Highway and Bridge Authorities.
Gross weight (of vehicle carrying the load) exceeding 80,000 kgs (78.74 tonnes) up to 150,000 kgs (157.63 tonnes)	Two (2) clear days' notice to Police and 5 clear days' notice with indemnity to Highway and Bridge Authorities.
Gross weight (of vehicle carrying the load) exceeding 150,000 kgs (147.63 tonnes)	Highways Agency Special Order (8 weeks' notice) plus clear days' notice to Police and 5 clear days' notice with indemnity to Highway and Bridge Authorities.
Width	
Width exceeding 3.0 metres (9' 6") and up to 5.0 metres (16' 5")	Two (2) clear days' notice to the Police.
Width exceeding 5.0 metres (16' 5") up to 6.1 metres (20')	Highways Agency (10 days' notice) form VR1 plus 2 clear days' notice to Police.
Width exceeding 6.1 metres (20')	Highways Agency Special Order (8 weeks' notice) plus 5 clear days' notice to Police and 5 clear days' notice with indemnity to Highway and Bridge Authorities.
Length	
When exceeding 18.75 metres (60' 1") and up to 30 metres (98' 5") rigid (Vehicle or train of vehicles)	Two (2) clear days' notice to the Police.
When exceeding 30 metres (98' 5") rigid	Highways Agency Special order (8 weeks' notice) to the Police and 5 clear days' notice with indemnity to Road and Bridge Authorities.