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Report on Small-scale Technologies for Utilization of Associated Gas

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Report on Small-scale Technologies for Utilization of Associated Gas

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Carbon Limits works with public authorities, private companies, finance institutions and non-governmental organizations to reduce emissions of greenhouse gases from a range of sectors. Our team supports clients in the identification, development and financing of projects that mitigate climate change and generate economic value, in addition to providing advice in the design and implementation of climate and energy policies and regulations.

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Executive Summary

This report provides an in-depth review of the technical aspects of 15 gas utilization technologies applicable for small volumes of associated gas as well as the financial prospects of implementing these utilization options on typical associated gas flare sites.

In summary, the analysis in the report concludes that:

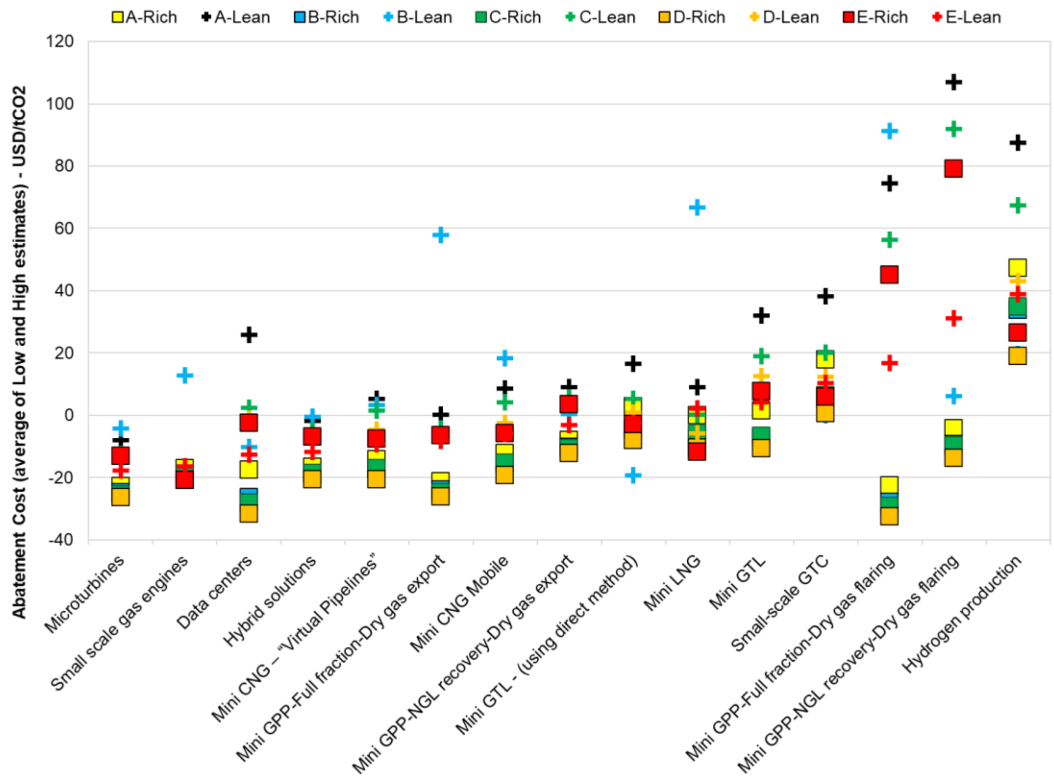
- While associated gas recovery, particularly in smaller capacities, faces major technical and financial barriers to implementation, significant efforts by suppliers have been made in recent years (with further developments still under R&D) to overcome the technical hurdles and improve economic viability.
- For almost all associated gas flare situations, technically viable solutions do exist, and in many cases, investment in flare gas recovery and utilization can be economically viable.
- Many parameters impact the financial outlook and achievable emission reductions of deploying a utilization option, most notably:
  - production profile (volume & composition of the associated gas and the way it changes over time).
  - geographic location (e.g., country of deployment, market conditions) has considerable impact on the project costs as well as the product values.
  - site conditions (e.g., offshore/onshore, extreme ambient conditions) affect capital costs as well as operating expenditure.
- Nevertheless, for any production profile and/or any geographic/site conditions, careful selection of the utilization technology and its design elements will help improve the economics of the project, including:
  - choice of the best-suited utilization option from the available technologies, based on specifications of the associated gas profile and the site location.
  - type of pretreatment deployed to maximize the highest value products at the lowest cost,
  - optimal sizing, i.e., selecting sizing based on either average flowrate over the project lifetime, minimum flowrate, maximum flowrate or another sizing which results in optimum returns. Note: Size selection will have an impact on the reduction in flaring achieved, sometimes very large impact.
- Financial incentives or flaring regulations, particularly flare payments/penalties, can have a big impact on the viability of gas utilization investments.

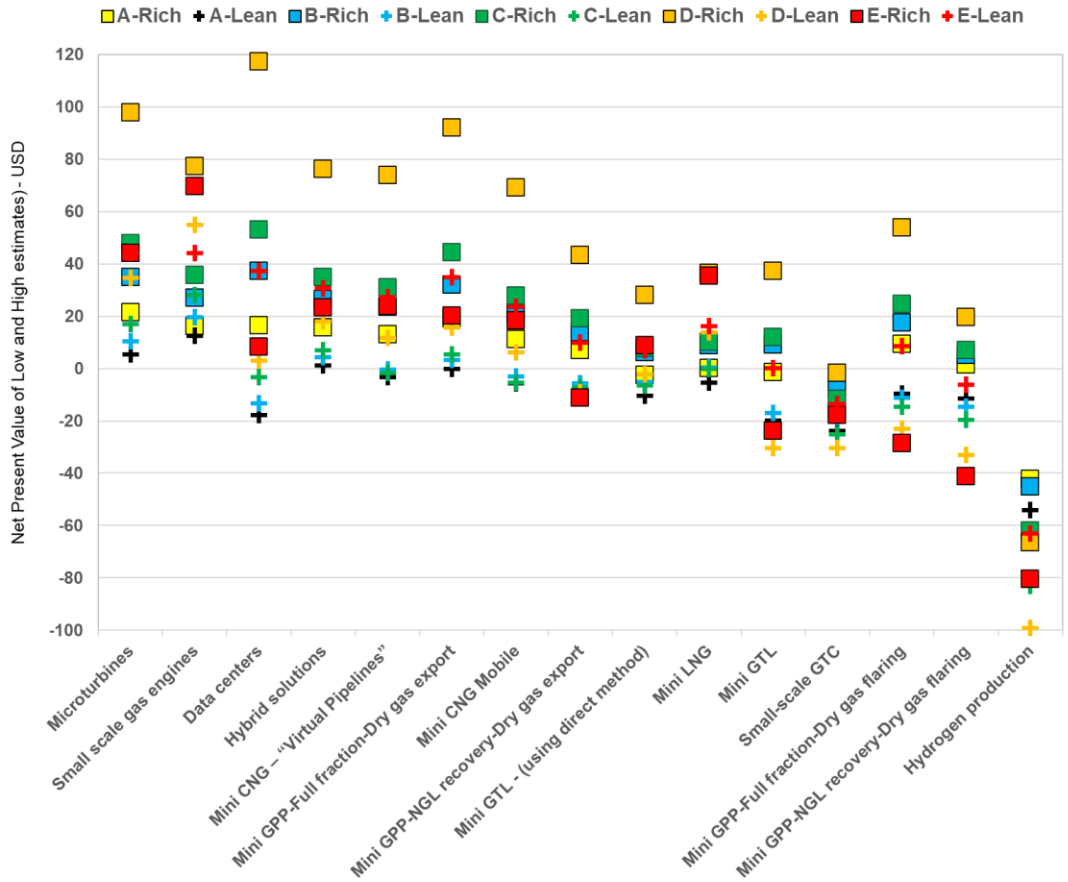
In total, 5 different production profile (A-profile, B-profile, C-profile, D-profile, and E-profile) are studied in this report, each representing a typical small-scale associated gas profile, with average rate of 2.4, 4.5, 6.3, 10.2 and 12.6 MMSCFD, respectively; and each showing a different behavior in flowrate variations over time. For each profile, 2 gas compositions have been assumed, one ‘lean’ and one ‘rich’ (i.e., rich includes larger quantities of heavier hydrocarbons).

This study analyzes net present values and abatement costs (i.e., reduction in tonnes of CO_2 emitted per USD invested) for the 5 different production profiles each with the 2 different gas compositions.

A graphical representation of the average abatement cost and net present values results for the 15 utilization options and 10 production profile/composition combinations are presented in Figures 1 below.

Figure 1 - Abatement cost and NPV (average of Low & High estimates) for the 15 utilization options and the 10 production-composition profiles evaluated (in US$ millions).





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Acronyms and Abbreviations

Abbreviation and acronyms	Full Form
AGR	Acid Gas Recovery
AG	Associated gas
ANG	Adsorbed natural gas
APG	Associated petroleum gas
API	American Petroleum Institute
ASIC	Application-specific integrated circuit
ASU	Air separation unit
ATEX	Atmosphere explosibles (fr.), explosive atmospheres
bbl	Barrel
BCM	Billion cubic meters
BTU	British thermal unit
C1/CH4	Methane
C2	Ethane
C3	Propane
C4	Butane
C5	Pentane
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilization
CCUS	Carbon Capture and Utilization or Storage
CH3OH	Methanol
CHP	Combined heat & power
Cl	Chlorine
CNG	Compressed natural gas
CO	Carbon monoxide
CO2(-eq.)	Carbon Dioxide (equivalent)
EF	Emission Factor
EPC	Engineering, procurement and construction
FGR	Flare Gas Recovery
FT	Fischer–Tropsch process
GGE	Gasoline gallon equivalent
GGFR	Global Gas Flaring Reduction Partnership
GHG	Greenhouse Gas
GTC	Gas-to-chemicals
GTL	Gas-to-liquids
GWP	Global Warming Potential
h	hour
H2	Hydrogen
H2O	Water
H2S	Hydrogen Sulphide
IEA	International Energy Agency
JSC	Joint-stock company
kg	Kilogram
(k)m	(Kilo-)meter
kt	Kilo tonne
kWh	Kilowatt-hour
LHV	Lower Heating Value
LLC	Limited liability company
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas

Abbreviation and acronyms	Full Form
max	Maximum
min	Minimum
MJ	Megajoule
MMSCFD	Million SCF per day
Mmt	Million Metric Ton
mt	Metric Ton
Mt	Million ton (used in lieu of Mmt on some graphs)
MTPA	Million ton per annum
N2	Nitrogen
N/A	Not available / not applicable
NCM	Normal cubic meter
NFPA	National Fire Protection Association
NGL	Natural gas liquids
NH3	Ammonia
NO_x	Nitrogen oxides
NPV	Net Present Value
nr	Number
OPEX	Operational Expenditure
(P/T)FLOPS	(Peta-/Tera) Floating-point Operations Per Second
ppm(v)	Parts per million (volumetric)
psi(g)	Pounds per square inch (gauge)
PV	Photovoltaic
R&D	Research & development
s	Second
SCF	Standard cubic feet
SCM	Standard cubic meter
SCR	Selective Catalytic Reduction
SMR	Steam methane reforming
SO_x	Sulphur oxides
SRU	Sulphur recovery unit
t	ton
tCH4	Ton of methane
tCO2	Ton of Carbon dioxide
TPD	Tons per day
TRL	Technology readiness level
UL	Underwriters Laboratories
US	United States
USA	United States of America
USD	United States Dollars
V	Volume
W (kW, MW, GW)	Watt (kilowatt, megawatt, gigawatt)
Wh (kWh, MWh, GWh)	Watt-hour (kilowatt-hour, megawatt-hour, gigawatt-hour)
WP	Work package

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1. Introduction

According to the World Bank, gas flaring has oscillated between 140 and 150 BCM per year over the last ten years[1]. In 2020, seven countries (Russia, Iraq, Iran, the United States, Algeria, Venezuela and Nigeria) accounted for roughly two-thirds (65%) of global gas flaring while producing about 40% of the world's oil each year. Though 40% of the flaring volume results from large flares (Figure 2), flares with less than 0.01 BCM/y (approximately 1 MMSCFD), constitute the majority of flare sites (Figure 3). This is particularly the case in North America and Russia where there are hundreds of small-scale flare sites.

Figure 2: Distribution of gas flaring by size - IEA[2]

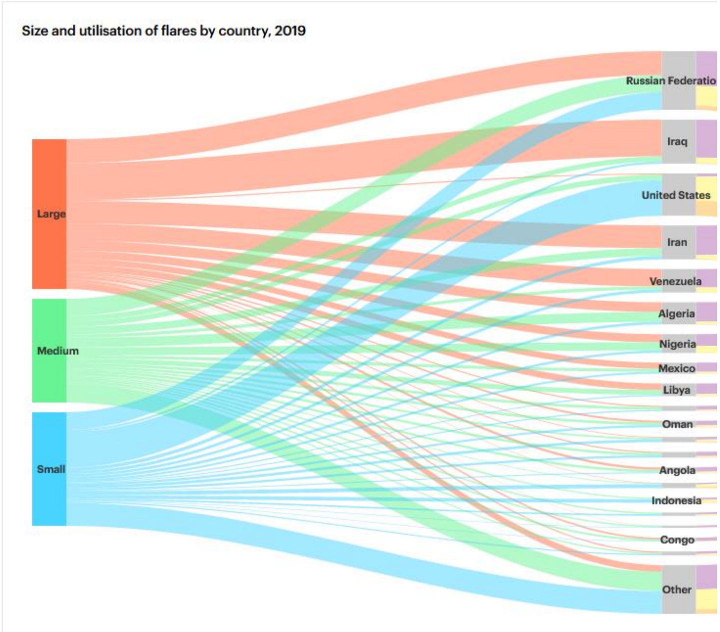
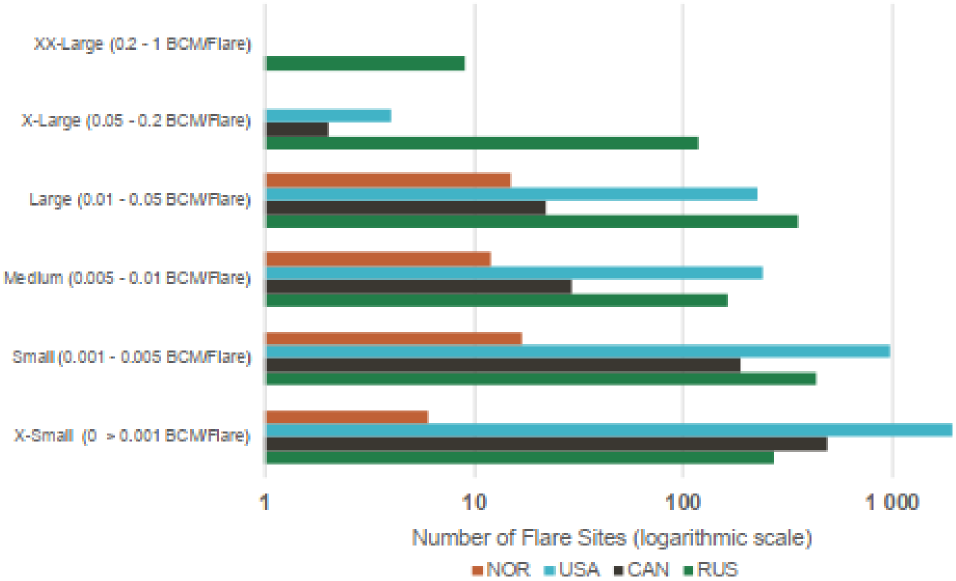


Figure 3 - Number of flare sites categorized in different flare size categories for Norway, US, Canada, and Russia[3]



These small flaring sites represent some specific challenges in developing utilization options, including:

- Conventional technologies typically require a minimum volume of reliable gas supply, which often represents a challenge at small sites with highly variable gas supply, and typically declining flowrates over time.
- Associated gas often has unfavorable compositions and impurities which sometimes represent a challenge in developing utilization options.

[1] https://thedocs.worldbank.org/en/doc/1f7221545bf1b7c89b850dd85cb409b0-0400072021/original/WB-GGFR-Report-Design-05a.pdf
[2] https://www.iea.org/commentaries/putting-gas-flaring-in-the-spotlight
[3] (Source: Carbon Limits 2018)

- There have historically been unattractive economies of scale for lower volumes of flare gas, therefore high abatement costs.

Despite the challenges mentioned above, considerable progress has been made in the last decade to improve the existing technologies and to develop new solutions for smaller sites that can reduce the unit costs, enhance scalability, and offer more flexibility with regards to feedstock requirements.

This study presents a detailed overview of the current status of small scale (0.1-15 MMSCFD) gas processing and gas utilization option. The options reviewed include gas treatment and processing, compressed natural gas (CNG) solutions, liquefied natural gas (mini-LNG), power generation using different technologies (conventional gas engines, microturbines and co-generation solutions), gas to liquids (mini-GTL) based on direct and indirect methods, gas-to-chemicals (mini GTC), adsorbed natural gas (ANG), data centers deployed on upstream oil & gas locations, and hydrogen production.

This report includes four main elements. **Section 2** provides an overview of small-scale utilization technologies. A set of technologies has then been selected for further evaluation and the **section 0** presents a technical evaluation and economic assessment of the utilization technologies. **Section 4** provides results of a technoeconomic model that was constructed to analyze emission reduction estimates & abatement cost assessments for each technology under a variety of scenarios. Finally, **section 5** presents two Case-studies of the implemented APG utilization technologies.

List of the technology providers and operators who have participated in the study is presented in **Annex 1**.

2. Overview of Small-Scale Utilization Technologies

The section provides an overview of the relevant available solutions for utilization of associated natural gas in small amounts of below 15 MMSCFD (or 0.15 BCM/y) from upstream production facilities including:

- Scaled gas processing unit and NGL recovery (also called mini-GPP), including the option to perform full fractionation of the AG and the option to recover the condensates + dry gas (without full fractionation),
- Small-scale gas engines,
- Microturbines,
- Flare gas recovery ejectors (not as an ultimate utilization option, but rather an auxiliary solution)
- Cogeneration solutions (e.g., gas engine + batteries),
- Small-scale gas / Mini LNG solutions,
- Adsorbed natural gas storage and transport (not analyzed in abatement cost assessment section, due to low maturity for AG applications),
- Mini CNG (considering virtual pipelines or cylinder/container),
- Mobile CNG solutions,
- Small scale hydrogen production,
- Mini/small GTL (gas-to-liquid), both the direct reforming method and the syngas method,
- Small-scale GTC (gas-to-chemical) such as small-scale ammonia or methanol plants,
- Data centers.

These options are reviewed with respect to the level of maturity (i.e., degree of Technical Readiness Level) based on the level of implementation and the time since the technology became available.

For this purpose, two indices have been used to rank the level of maturity.

a) Evaluation of the technical readiness levels as “Mature & Commercial”, “Commercial”, “Under Pilot Testing” or “Under Development” or “Research Phase”.
  - Mature and commercial: Around 100 or more deployments globally,
  - Commercial: with more than 10 but less than 100 installations” globally,

- Under Pilot testing – Deployment is ongoing in some oil fields, less than 10 installations in total,
- Under development – research phase.

b) Evaluation of the technical readiness levels based on the API 17N scale:

Table 1 - Technical Readiness Level scoring as per API 17 N

	TRL (API 17 N)	**Development Stage Completed**	**Definition of Development Stage**
Concept	**0**	**Unproven Concept** (Basic R&D, paper concept)	Basic scientific/engineering principles observed and reported; paper concept; no analysis or testing completed no design history.
Proof-of-Concept	**1**	**Proven Concept** (As a paper study or R&D experiments)	a) Technology concept and/or application formulated b) Concept and functionality proven by analysis or reference to features common with/to existing technology c) No design history; essentially a paper study not involving physical models but may include R&D experimentation
	2	**Validated Concept** (experimental proof of concept using physical model tests)	Concept design or novel features of design is validated by a physical model, a system mock-up or dummy and functionally tested in a laboratory environment; no design history; no environmental tests; materials testing and reliability testing is performed on key parts or components in a testing laboratory prior to prototype construction
Prototype	**3**	**Prototype Tested** (System function, performance and reliability tested)	a) Item prototype is built and put through (generic) functional and performance tests; reliability tests are performed including reliability growth tests, accelerated life tests and robust design development test program in relevant laboratory testing environments; test are carried out without integration into a broader system b) The extent to which application requirements are met are assessed and potential benefits and risks are demonstrated
	4	**Environment Tested** (Pre-production system environment tested)	Meets all Requirements of TRL 3; designed and built as production unit (or full-scale prototype) and put through its qualification program in simulated environment (e.g. hyperbaric chamber to simulate pressure) or actual intended environment (e.g. subsea environment) but not installed or operating; reliability testing limited to demonstrating that prototype function and performance criteria can be met in the intended operating condition and external environment
	5	**System Tested** (Production system interface tested)	Meets all the requirements of TRL 4; designed and built as production unit (or full-scale prototype) and integrated into intended operating system with full interface and functional test but outside the intended field environment
Field Qualified	**6**	**System Installed** (Production system installed and tested)	Meets all the requirements of TRL 5; production unit (or full - scale prototype) built and integrated into intended operating system; full interface and function test program performed in the intended (or closely simulated) environment and operated for less than three years; at TRL 6 new technology equipment might require additional support for the first 12 to 18 months
	7	**Field Proven** (Production system field proven)	Production unit integrated into the intended operating system, installed and operating for more than three years with acceptable reliability, demonstrating low risk of early life failures in the field

Table 2 provides results of the TRL (technical readiness level) assessment based on two methods mentioned above, and a brief description of each technology.[4] Where a technology is considered 'Mature and commercial', a list of the leading providers is included.

Table 2 - Brief description of all utilization technologies covered in this report and technical readiness level evaluation.

Technology: Hybrid solutions			
Short description	An electrical power generation system that derives energy from a combination of AG and renewable sources, such as photovoltaics or wind. Note that co-generation in this context does not refer to a combined heat and power system. The advantage of combining AG and renewable power generation could be to overcome problems of intermittency from both sources. In addition, the power generation load can be managed more efficiently.		
Technical Readiness Level (TRL)	Under development (for associated gas applications)	**TRL** *(API scale)*	2 – Proof-of-Concept (Validated Concept) to 5 – Prototype (System Tested)
Comments on TRL	No examples of a hybrid installation discovered at an upstream facility using AG. Aggreko comes closest by offering hybrid power systems that minimize fuel usage (e.g., diesel) specifically for AG, and offers back-up to solar PV.		
References	https://www.aggreko.com/en/case-studies/utilities/hybrid-solution-supports-grid-and-reduces-emissions https://www.wartsila.com/marine/build/engines-and-generating-sets/hybrid-solutions https://www.siemens-energy.com/global/en/offerings/storage-solutions/battery-energy-storage/siestart-hybrid-solutions.html		

Technology: Hydrogen production			
Short description	Natural gas is the most common raw material for producing hydrogen and in principle this could be done at a small scale at upstream locations with AG, though it is normally done at a larger scale at downstream locations. Firstly, the AG needs upgrading to methane and then the methane may be converted to hydrogen by; i) steam methane reforming (SMR), ii) methane pyrolysis, or iii) partial oxidation. The hydrogen may be transported to market as a liquid (cryogenic liquid hydrogen, methanol, ammonia or cyclohexane) or in solid form as a hydride compound.		
Technical Readiness Level (TRL)	Under development (for associated gas applications)	**TRL** *(API scale)*	3 – Prototype (Prototype Tested) (for associated gas applications)
Comments on TRL	SMR at downstream locations is mature and commercial, but not at upstream locations. The addition of CCS to SMR in order to remove carbon dioxide emissions is at the level of Under Pilot Testing – again at downstream locations. Pyrolysis is at Under development stage.		
Leading providers *(for Mature & commercial)*	Not applicable due to low TRL		

[4] The following sources have been used for this assessment:
Previous experience of the Carbon Limits and Vygon Consulting: Both Consortium Members have been involved in a number of studies and techno-economic evaluation assignments of flare reduction options. The experience from those assignments shall be used as a starting point.
Information from technology providers: Case-studies, technology specs, and other material by technology providers. The information shall be used in conjunction with other sources and with a critical eye to avoid overrating a technology based on potentially promotional material. No interviews shall be done under this WP, but recent interview details carried out by Consortium Members may be used.
Operator case-reports: Published material by oil companies that have implemented projects to recover small volumes of associated gas shall be used to help with the assessment of the technology readiness level (TRL).
Other literature review such as research papers, technology-review reports and presentations and similar publications will be leveraged.

References	Hiiroc Ltd - thermal plasma electrolysis (TPE) of natural gas Scenarios for hydrogen production and transport from AG in a remote location: Korneev et al., 2019 - Russian academic paper from 2019: reaction modelling and proposed design of an industrial reactor: (Parkinson et al., 2018) Machlin, V.A.; Cetaruk, J.R. Modern technologies of producing synthesis gas from natural and associated gas. Sci. Tech. J. Chem. Ind. Today 2010, 3, 6–17 Not AG related: York, A.P.E.; Xiao, T.; Green, M.L.H.; Brief overview of the partial oxidation of methane to synthesis gas. Top. Catal. 2003, 22, 345-358, 10.1023/A:1023552709642. (Barkan & Kornev, 2017) Morenov, V.A.; Leusheva, E.L.; Buslaev, G.V.; Gudmestad, O.T.; System of comprehensive energy-efficient utilization of associated petroleum gas with reduced carbon footprint in the field conditions. Energies 2020, 13, 1-14, 10.3390/en13184921.

Technology: Mini-GTL via syngas production			
Short description	Gas-to-liquids (GTL) technology can produce liquid fuels that are of higher value and easier to transport to market than natural gas. The first step is to generate a synthetic gas (syn-gas, H_2+CO) from a sulfur-free natural gas by a process known as reforming. Then the syngas is fed to a catalytic conversion process, e.g., Fischer-Tropsch (FT) process, to generate liquid hydrocarbon products, also known as synthetic crude. The syncrude is then refined to produce final liquid products such as naphtha, kerosene, diesel, lubricants, solvents and waxes. GTL can function across a range of scales. This study considers the range 2-15 MMSCFD associated gas.		
Technical Readiness Level (TRL)	Commercial	**TRL** *(API scale)*	6 – System Installed (Production system installed and tested)
Comments on TRL	• 20+ years since pilot testing • 5+ years since numerous commercial deployments • Less than 100 deployment cases • GGFR comment in 2019: *"We have come to a point where currently only a few mini-GTL technologies have been proven by plant demonstration runs and are now available for commercial consideration for flare gas monetization."*		
References	Gas-to-liquids Conversion - Arno de Klerk Department of Chemical and Materials, Engineering University of Alberta, Edmonton, Canada Mini-GTL Technology Bulletin		
Technology: Mini-GTL with direct conversion			
Short description	As compared to the indirect conversion, the direct process involves conversion of hydrocarbons to liquid chemicals without intermediate production of syngas. Several direct methods have been tested, the most developed are direct oxidation of methane to methanol and oxidative coupling of methane.		
Technical Readiness Level (TRL)	Under Pilot testing for AG application	**TRL** *(API scale)*	6 – System Installed (Production system installed and tested)
Comments on TRL	*As compared to Mini-GTL via syngas production, the direct method has a much lower penetration for associated gas uses. Therefore, it is classified as "Commercial" due to the relatively lower maturity.*		
References	Gas Techno Nordic GTL – a pre-feasibility study on sustainable aviation fuel Mini-GTL Technology Bulletin		

Technology: Small scale gas engines			
Short description	Robust, heavy-duty internal combustion engines designed to run on AG and generate electrical power or combined heat and power (CHP) output. Available in unit sizes up to 30 megawatts (MW) and can achieve an electrical efficiency of above 45% (although with typical AG, efficiency is generally lower due to lower methane number), and under preferable circumstances can compete with gas turbines. Although many gas engines can run on gas of various compositions, the typical nominal design point is a gas that is 70–85% methane by volume. While engines can operate on gases with lower methane content, a change in performance can be expected. The load factor can be scaled down to 40% of the design capacity in case of lower feedgas volume.		
Technical Readiness Level (TRL)	Mature and commercial	**TRL** *(API scale)*	7 – Field Qualified (Field Proven)
Comments on TRL	The most mature technology option for power generation		
References	Best Available Techniques Economically Achievable to Address Black Carbon from Gas Flaring: EU Action on Black Carbon in the Arctic – Technical Report 3 GGFR Technology Overview – Utilization of Small-Scale Associated Gas. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf		

Technology: Scaled Gas Processing Unit and NGL Recovery			
Short description	Natural gas liquids recovery is a process for separating ethane and heavier hydrocarbons (C2+) from AG in order to produce ethane, LPG, C_5+ & natural gas streams (propane and butane streams can also be separated through fractionation). Ethane, LPG & C5+ hydrocarbons can be then transferred to storage facilities and sold, while natural gas may be either sent to flare or utilized in any manner. The range of products at an individual unit will depend upon the composition of AG, the availability of a market for the product in question and economic feasibility of its recovery: although virtually up to 100% of NGLs can technically be extracted, the “reasonable” rate of recovery will vary substantially across regions. Scaled gas processing and NGL recovery is perfectly suited for remote site deployment far from infrastructure and for all fields with short or long remaining field life (since equipment is easily re-deployable after end of field life). This technology may be particularly attractive where local markets exist for NGL products and where road or rail infrastructure exists for product evacuation. In addition, in case marketing of individual products such as LPG and condensate is challenging or uneconomic due to the lack of transport infrastructure or potential consumers, they can often be blended into the crude oil stream.		
Technical Readiness Level (TRL)	Mature and commercial	**TRL** *(API scale)*	TRL – 7: Field Proven Technology
Comments on TRL	Scaled gas processing and NGL recovery technology is mature and has been successfully applied in the oil and gas industry across various regions for decades. In particular, modular gas processing and NGL recovery units were commercially available already in the early 1970s.		
Leading providers *(for Mature & commercial)*	• Aerogas • Air Liquide Engineering & Construction • Aspen Engineering Services • BINGO Interests • Expansion Energy • GazSurf • GTUIT • MTR • Nacelle • Pioneer Energy		

References	Air Liquide Engineering & Construction (2021) Natural Gas Liquids Recovery. Recovering Natural Gas Liquids from natural gas. Available at: https://www.engineering-airliquide.com/natural-gas-liquids-recovery GazSurf (2021) About us. GazSurf official website. Available at: https://www.gazsurf.com/en/about-us GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. Gas processing, pp. 5-14. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf Linde (2016) Standard-Plus. A new standard for standard NGL plants, p. 2. Available at: https://www.leamericas.com/en/images/Standard%20Plus%20Brochure%202016%20for%25%2020Web_tcm136-257181.pdf

Technology: Microturbines and Small-Scale Gas Turbines			
Short description	Microturbines are small combustion turbines with outputs of 25 to 500 kW (while conventional gas turbine sizes range from 500 kW to 350+ MW). Like larger gas turbines they can be used in power-only generation or in combined heat and power (CHP) systems. Gas turbines of higher capacity, e.g. 1.8 MW models, are also applicable for small-scale AG utilization projects and will also be covered in this section. Depending on the technology provider, microturbines and small-scale gas turbines are available to operate on a variety of fuels, including natural gas, sour gases (with high H2S content), low heating value gases, and liquid fuels such as gasoline, kerosene, and diesel fuel / distillate heating oil, gas condensate and pyrolysis oil. They are widely used for autonomous heat and power generation, particularly in the oil and gas sector.		
Technical Readiness Level (TRL)	Mature and commercial	**TRL** *(API scale)*	TRL – 7: Field Proven Technology
Comments on TRL	Microturbines technology is mature and has been successfully applied in different regions for autonomous heat and power generation for about two decades. Today's microturbine technology is the result of development work in small stationary and automotive gas turbines, auxiliary power equipment and turbochargers, much of which was pursued by the automotive industry beginning in the 1950s. Microturbines entered field testing in the oil & gas sector around 1997 and began commercial service in 2000.		
Leading providers *(for Mature & commercial)*	• Ansaldo Energia • Capstone Turbine Corporation • OPRA Turbines • SKB Turbina		
References	Ansaldo Energia (2021) Micro Gas Turbines AET100. Ansaldo Energia official website. Available at: https://www.ansaldoenergia.com/business-lines/new-units/microturbines Barney L. Capehart (2016). Distributed Energy Resources (DER). Microturbines. Whole Building Design Guide. National Institute of Building Sciences. Available at: https://www.wbdg.org/resources/distributed-energy-resources-der Capstone Turbine Corporation (2021) Products section. Capstone Turbine Corporation official website. Available at: https://www.capstoneturbine.com/products Energy Solutions Center. Understanding CHP. 4. CHP Technologies. 4.2 Microturbines. Available at: https://understandingchp.com/chp-applications-guide/4-2-microturbines/ SKB Turbina (2021) Civilian products. Micro gas turbine units. SKB Turbina official website. Available at: https://www.skb-turbina.com/produkcziya-grazhdanskogo-naznacheniya/malogabaritnyie-gazoturbinnyie-dvigateli-i-energosistemyi/ [in Russian]		

Technology: Mini LNG – "Virtual pipelines"	
Short description	LNG (liquefied natural gas) is natural gas that has been cooled down to liquid form (between -145°C and -163°C) for ease and safety of non-pressurized storage or transport (LNG can be transported by road, rail and sea). Its typical energy density amounts to about 22 MJ/liter, i.e., 2.5 times higher in comparison to CNG and over 600 times that of the same volume of natural gas at standard conditions. The liquefaction process is carried out at LNG plants. After delivery to a consumer LNG can be re-gasified, i.e., converted back to natural gas, at special terminals (regasification plants / terminals) or used directly as LNG.

	In international practice the term "small-scale" or "mini-LNG" typically refers to plants with the liquefaction capacity of up to 1 MTPA (about 130 MMSCFD). Where a pipeline may be uneconomic or not yet constructed, small-scale LNG may offer a "virtual pipeline" to transport gas to supply power plants, industrial consumers, and / or for use as a fuel for cars and trucks. Construction of a small-scale LNG plant may be a particularly attractive solution in remote regions located far from the centralized gas supply system, where there is local demand for natural gas. The economic efficiency of the project will largely depend on the value of LNG compared to alternative fuels in a particular area, in other words the position of LNG in the inter-fuel competition will frequently be the decisive factor.		
Technical Readiness Level (TRL)	Mature and commercial	**TRL** *(API scale)*	TRL – 7: Field Proven Technology
Comments on TRL	Mini LNG technology is mature; numerous small-scale projects have been successfully implemented for decades. In particular, in the US small-scale LNG industry was initially developed in the 1960s and 1970s, and generally consisted of peak shaving facilities for winter gas supply. Today small-scale liquefaction plants can be found across different countries and are frequently used for autonomous gasification of remote areas. In some cases, the produced LNG is also exported.		
Leading providers *(for Mature & commercial)*	• Cryogas • Cryogenmash • Cryostar SAS • Expansion Energy • Galileo • GE • JGC Holdings Corporation • Wärtsilä		
References	B. Price, M. Mahaley & W. Shimer (2014) Optimize small-scale LNG production with modular SMR technology. Gas Processing & LNG. Available at: http://www.gasprocessingnews.com/features/201404/optimize-small-scale-lng-production-with-modular-smr-technology.aspx Cryogas (2018) Liquefied natural gas. Cryogas official website. Available at: https://cryogenmash.ru/en/about/about-cryogenmash.php Cryogenmash (2021) About Cryogenmash. Cryogenmash official website. Available at: https://cryogenmash.ru/en/ GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. Mini-LNG, pp. 29-34. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf Wärtsilä (2016) Product Guide. LNG plants –mini and small scale liquefaction technology. Available at: https://cdn.wartsila.com/docs/default-source/product-files/ogi/lng-solutions/brochure-o-ogi-lng-liquefaction.pdf		

Technology: Mini CNG – Motor fuel and "Virtual Pipelines"	
Short description	CNG (compressed natural gas) is made by compressing natural gas to less than 1% of the volume it occupies at standard atmospheric pressure. Its energy density amounts to about 9 MJ/liter, i.e., almost 250 times higher in comparison to that of natural gas before the compression. CNG is primarily used as a fuel for motor vehicles that have been either converted or specifically manufactured to run on compressed natural gas. The compression typically occurs directly at CNG filling stations that source natural gas from pipelines. CNG can also be used onshore to create a "virtual pipeline" to supply small-scale power plants, industrial consumers, households or CNG filling stations that do not have access to conventional pipeline gas. In this case, CNG is stored in special containers that typically consist of stacked pressurized cylindrical gas bottles and delivered to the final consumers by trucks. One truck typically can deliver about 0.25 MMSCF in one round.

	CNG has a considerably lower energy density in comparison to LNG, which makes it a less viable option in case of larger AG production volumes and / or longer distances to market since a substantially greater number of trucks would be required for delivery of the product to consumers. However, at the same time CNG offers lower capital costs relative to the liquefied gas, which can make it a particularly attractive option in the case of the opposite scenario – smaller volumes of AG production (<~5 MMSCFD) and / or shorter distances to market.		
Technical Readiness Level (TRL)	Mature and commercial	**TRL** *(API scale)*	TRL – 7: Field Proven Technology
Comments on TRL	Mini CNG technology is mature and has been successfully implemented for decades. First natural gas engine was introduced as early as in 1915-1916. By the 1940-50s, CNG was widely used in Germany, Denmark, Norway, Romania, Finland and France, and especially Italy, where replaceable gas cylinders became widespread. Today over 28.5 million vehicles use natural gas as a fuel globally with CNG accounting for the major part. Cases of application of CNG for gasification of consumers via virtual pipelines are less common, but also exist in the global practice. In particular, Galileo has successfully implemented virtual pipelines in Bulgaria, which enabled gasification in 13 municipalities, and Argentina. Virtual pipelines have also been successfully deployed in North America by Certarus and other companies. At the same time, it should be highlighted that in the global practice natural gas for compression is typically sourced from pipelines, while the cases of deployment of the CNG technology for AG utilization are quite limited. One of the examples includes a pilot project that was implemented by GE and Ferus NGF for Equinor in the Bakken Shale. As part of this AG utilization project dry gas was sent to a mobile compressor designed by GE, the highly-pressurized gas then traveled inside Ferus' tube trailers pulled by heavy duty trucks that delivered it to rigs and equipment for use as a fuel.		
Leading providers *(for Mature & commercial)*	• Certarus • Clean Energy • CNG Services • Galileo • Houpu Clean Energy • Quantum Fuel Systems		
References	Belyaev S.V., Davydkov G.A. (2010) Problems and prospects of using gas engine fuels in transport. Resources and Technology journal. [in Russian] Certarus (2021) CNG Virtual Pipeline Systems. Certarus official website. Available at: https://certarus.com/virtual_pipeline.php Clean Energy (2021) CNG Virtual Pipeline Services. Clean Energy official website. Available at: https://www.cleanenergyfuels.com/services/virtual-pipeline-services CNG Services (2021) CNG Services official website. Available at: https://www.cngservices.co.uk/index.php/services/virtual-pipelines/ Galileo Technologies (2020) Virtual Pipeline. Galileo Technologies official website. Available at: https://www.galileoar.com/en/virtual-pipeline/ GE (2014) Taming North Dakota's Gas Flares. September 10, 2014. GE official website. Available at: https://www.ge.com/news/reports/taming-north-dakotas-gas-flares GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. CNG, pp. 27-28. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf NGV Global (2019). Current Natural Gas Vehicle Statistics. Available at: https://www.iangv.org/current-ngv-stats/ Quantum Fuel Systems (2021) Q-VP. Virtual Pipeline CNG Trailers. Quantum Fuel Systems official website. Available at: https://www.qtww.com/product/virtual-pipeline-cng/ US Department of Energy (2020) Natural Gas Vehicle Basics, p. 1 Available at: https://afdc.energy.gov/files/u/publication/natural_gas_basics.pdf		

Technology: Mobile CNG Filling Stations			
Short description	Mobile CNG filling stations are a compact technology mounted on either a truck or a trailer for mobility that allows to compress natural gas (that is usually sourced from a pipeline), store CNG and refuel CNG cars and other vehicles. One mobile CNG filling station can typically carry about 0.09 MMSCF. In technological terms, this solution is almost identical to the conventional CNG filling stations except for size and mobility.		
Technical Readiness Level (TRL)	Mature and commercial	**TRL** *(API scale)*	TRL – 7: Field Proven Technology
Comments on TRL	Since from the technological perspective mobile CNG filling stations are mostly identical to the conventional ones, numerous turn-key solutions are already commercially available and have been successfully applied across various countries, the technology is considered to be mature and commercial. E.g., Gazprom Gas-Engine fuel company alone currently operated 17 mobile CNG filling stations in Russia. At the same time, it should be highlighted that in the global practice natural gas for compression is typically sourced from pipelines. The cases of application of mobile CNG filling stations for AG utilization have not been identified.		
Leading providers *(for Mature & commercial)*	• CNG Center • Houpu Clean Energy • KAMAZ Industrial Components • TEGAS		
References	CNG Center. Mobile CNG Fueling equipment. CNG Center official website. Available at: https://cngcenter.com/cng-equipment/mobile-cng-fueling-station/ GasLiner (2015) Technology section. GasLiner official website. Available at: http://gasliner.com/ Gazprom Gas-Engine Fuel (2020) The subprogram for the development of the NGV market in the Russian Federation was approved. [in Russian] Available at: https://gmt.gazprom.ru/press/news/2020/03/34/ Houpu Clean Energy Co. (2020) Products. Vehicle Application section. Houpu Clean Energy Co. official website. Available at: http://en.hqhop.com/prd.aspx?t=14 KAMAZ Industrial Components (2021) Products. Mobile compressed gas filling stations. KAMAZ Industrial Components official website. Available at: https://industrial-kamaz.ru/en/products/agnks/		

Technology: Small-scale GTC			
Short description	Natural gas can be used as a feedstock for the production of chemical products – ammonia (NH_3) or methanol (CH_3OH) – in small-scale gas-to-chemical (GTC) plants. The first step in the process is the same for both ammonia and methanol and involves the generation of hydrogen via one of the three processes: steam methane reforming, which is the most commonly used option, dry reforming of methane or partial oxidation of methane. Steam methane reforming (SMR) is a reaction, in which methane is heated with steam, usually with a catalyst, in order to obtain a mixture of carbon monoxide and hydrogen, which is also known as syngas or synthesis gas (see also the Hydrogen technology table). Dry methane reforming refers to the catalytic reforming of CH_4 with carbon dioxide to produce syngas, while partial oxidation is a technically mature process in which natural gas is mixed with a limited amount of oxygen in an exothermic process. In order to produce ammonia, the hydrogen is then catalytically reacted with nitrogen: $3H_2 + N_2 \rightarrow 2NH_3$. The nitrogen required for the process is separated from the atmospheric air at an air separation unit (ASU). It should be noted that this process tends to be quite energy intensive. In the case of methanol production, the hydrogen reacts with carbon monoxide, also over a catalyst: $CO + 2H_2 \rightarrow CH_3OH$.		
Technical Readiness Level (TRL)	**For small-scale ammonia:** Commercial **For small scale methanol:** Mature and commercial	**TRL** *(API scale)*	TRL – 7: Field Proven Technology

Comments on TRL	Although for both ammonia and methanol small-scale solutions are commercially available, the number of existing projects is limited relative to other natural gas monetization options. However, it should be noted that small-scale methanol plants (in comparison to small-scale ammonia plants) are generally more common to oil and gas companies since the product can be consumed on-site usually as a reagent that prevents hydrate formation or as a chemical at well site. In particular, this practice is used at fields in Siberia and the Far North. Ammonia, on the other hand, is used mainly in the production of nitrogen fertilizers, and given the relatively high cost of transportation of the product, finding a consumer of ammonia produced from AG may be challenging.
Leading providers *(for Mature & commercial)*	• Air Liquide • Bluescape Clean Fuels • CEAMAG • GasTechno • Haldor Topsoe • Johnson Matthey • New Technologies LLC • Safe Technologies Industrial Group
References	Air Liquide (2021) Our Technologies. Petrochemicals. Air Liquide official website. Available at: https://www.airliquide.com/engineering-construction/our-technologies Arora S. and Prasad R. (2016) An overview on dry reforming of methane: strategies to reduce carbonaceous deactivation of catalysts. RCS Advances. Issue 110. Available at: https://pubs.rsc.org/en/content/articlelanding/2016/ra/c6ra20450c Bluescape Clean Fuels (2020) Home. Bluescape Clean Fuels official website. Available at: https://bluescapecleanfuels.com/ CEAMAG (2021) Technologies. Ammonia. CEAMAG official website. Available at: https://www.ceamag.com/en/technologies/ammonia De Campos Roseno, K.T. et al. (2018) Syngas production using natural gas from the environmental point of view. Biofuels-State of Development, pp. 273-290. Available at: https://www.intechopen.com/chapters/59618 GasTechno (2020) Meet GasTechno. GasTechno official website. Available at: https://gastechno.com/ GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. Mini-GTL, pp. 35, 38, 40. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf Haldor Topsoe (2021) Annual Report 2020 Presentation. Available at: https://www.topsoe.com/hubfs/DOWNLOADS/DOWNLOADS%20-%20Annual%20reports/2020/Haldor%20Topsoe%20AR2020_20210223.pdf?hsLang=en ICIS (2010) Methanol Production and Manufacturing Process. 2010/04/27. Available at: https://www.icis.com/explore/resources/news/2010/04/27/9076036/methanol-production-and-manufacturing-process J. Jianga et al. (2018) Energy Consumption Optimization of a Synthetic Ammonia Process Based on Oxygen Purity. Chemical Engineering Transactions. Vol. 70, 2018. Available at: https://www.aidic.it/cet/18/70/081.pdf Johnson Matthey (2021) Methanol process. Johnson Matthey official website. Available at: https://matthey.com/en/products-and-services/chemical-processes/licensed-processes/methanol-process Nitrogen+Syngas (2018) Sustainable ammonia for food and power. Nitrogen+Syngas 354. July-August 2018, p. 6. Available at: https://www.protonventures.com/wp-content/uploads/2018/09/NS-354-Small-scale-plant-design-PROTON-VENTURES-3-1.pdf Pattabathula V., Richardson J. (2016) Introduction to Ammonia Production. AIChE. September 2016. Available at: https://www.aiche.org/resources/publications/cep/2016/september/introduction-ammonia-production Safe Technologies Industrial Group (2021) About us. Safe Technologies Industrial Group official website. Available at: https://zaobt.ru/en/about ThyssenKrupp website (2021) Small Scale Methanol. Available at: https://www.thyssenkrupp-industrial-solutions.com/en/products-and-services/chemical-plants-and-processes/methanol-plants/small-scale-methanol VYGON Consulting (2019) Gas Chemical Industry of Russia. Part 1. Methanol: Only Plans So Far. Executive Summary. March 2019. Available at: https://vygon.consulting/en/products/issue-1585/

Technology: Innovative use of electrical power production			
Short description	Gas engines and gas turbines produce electrical power and the potential market for this power may be limited by access to the power grid and/or local demand. In these cases, there may be an opportunity to establish power intensive industry at the upstream location in order to benefit from this potential source of electrical power. Two examples of such industries are data centers and water treatment. A data center is a facility that houses a multitude of powerful computers and systems necessary for their operation, processing large amounts of data efficiently and without interruption. Organizations use data centers to host their critical data and solve tasks that require significant computing power, such as graphic rendering or training of artificial intelligence models. Such facilities with proper equipment can also be used for cryptocurrency mining. Due to the features and amount of hardware typically placed in data centers, they tend to be very energy intensive. Water treatment requires electrical power and may be a source of agricultural irrigation supply or potable water. The source of water may be waste-water or salt water from underground aquifers or the sea. The availability of electrical power in an off-grid location such as an upstream site could enable water purification or desalination in a region suffering from water shortage.		
Technical Readiness Level (TRL)	Commercial	**TRL** *(API scale)*	TRL – 7: Field Proven Technology
Comments on TRL	In most regions, examples of implementation of data centers powered by electricity generated from AG are limited to pilot projects. Today they are most widely used in the US, where modular data centers are supplied by Crusoe Energy Systems. The company currently operates 40 modular facilities powered by electricity generated from AG in North Dakota, Montana, Wyoming and Colorado.		
Leading providers *(for Mature & commercial)*	• Crusoe Energy Systems		
References	Cambridge Dictionary (2021) Data center definition. Available at: https://dictionary.cambridge.org/dictionary/english/data-centre Cisco (2021) What Is a Data Center. Available at: https://www.cisco.com/c/en/us/solutions/data-center-virtualization/what-is-a-data-center.html Crusoe Energy Systems (2019) Digital Flare Mitigation. Crusoe Energy Systems official website. Available at: https://www.crusoeenergy.com/digital-flare-mitigation		

Technology: Adsorbed NG Storage and Transport			
Short description	Adsorbed natural gas (ANG) technology can 1.5 to 3 times the amount of gas to be stored in the same container volume, as compared to CNG, which reduces the thickness and weight of storage tanks. An adsorbent material such as activated carbon is placed inside each tank allowing more gas to be stored than if the tank was empty. However, 15% to 30% of the gas does get retained by the material after emptying the container after the first unloading event, reducing the effective capacity for subsequent filling.		
Technical Readiness Level (TRL)	***At industrial scale***: Under development ***For light commercial vehicles***: Commercial	**TRL** *(API scale)*	***At industrial scale***: 2 – Proof-of-Concept (Proven Concept) ***For light commercial vehicles***: 7 – Field Qualified (Field Proven)
Comments on TRL	Already commercial as fuel tanks for light commercial vehicles		
References	Ingevity - Adsorbed Natural Gas Storage of Natural Gas by Adsorption Process Adsorption method for the recovery of hydrocarbons from natural gas and associated petroleum gas https://cenergysolutions.com/ang-storage/		

Technology: Ejectors for flare gas recovery			
Short description	Gas ejectors use high-pressure motive fluid to compress low pressure gas and help transport the gas to a utilization point or pipeline. The pressure of the motive fluid should be typically 2-10 times larger than the required discharge pressure, dependent on the gas's properties and required output pressure. When utilizing high-pressure gas from existing sources, ejectors (also called eductors or jet pumps) have no running costs. A gas ejector has three connection points: one for the high-pressure gas; one for the low-pressure gas; and one for the discharge. There is a nozzle designed to mix the two incoming streams by converting the pressure energy of the high-pressure fluid into kinetic energy. The ejector is thus capable of compressing or boosting the pressure of the low-pressure gas.		
Technical Readiness Level (TRL)	Mature and commercial	**TRL** *(API scale)*	7 – Field Qualified (Field Proven)
Comments on TRL	• 21+ years since first commercial deployments • More than 100 deployment cases		
References	https://www.ipieca.org/resources/energy-efficiency-solutions/efficient-use-of-power/ejectors/ Ejector Technology for Efficient and Cost Effective Flare Gas Recovery		

3. Assessment of the Utilization Technologies

For this section, a subset of mall-scale technologies has been selected based on Section 2 for further analysis. Data collection was performed using (i) existing literature (ii) interviews with the technology providers and (iii) where possible, interviews with operators using the technology.

The summary of the data collected is presented in standardized summary tables:

Table 3 - Standardized summary table format for technology description

Example	
Overall Description: *General description of the technology including references to various source of information* **Notable about this technology:** *Key advantages and important influencing factors* **Notable limitations:** *A list of technical and non-technical limitations identified by the interviewees is presented. This list is by nature non exhaustive.*	*Picture including reference*
Capacity range (MMSCFD)	
Type of product produced	*Very different technologies (not necessarily interchangeable) are being reviewed. This section provides product types*
Amount of yield per MMSCF gas	*Not always relevant, for example for transport technologies*
Pre-treatment requirements	*This section documents the quality of the gas inlet requirement.*
Modularity	*This documents the solutions modularity and thus flexibility*
Other scalability potential	
Auxiliary/additional utilities required	*Other equipment requirements are listed*
Applicability (offshore/ onshore)	
Ambient temperature limitations	
Minimum feed pressure required	
Temperature operational range	
Other climatic constraints	
Other carbon footprint/ environmental impacts	
Safety Concerns	
Applicability for CCS/CCUS	
Other considerations	

3.1 Hybrid solutions

Co-generation or hybrid solutions	TRL: Under development API 2 - Proof-of-Concept *(Validated Concept)* to API 5 - Prototype *(System Tested)*
Overall Description: A novel approach to combine small scale power generation from AG with battery storage and/or renewable energy source such as solar PV or wind. No existing plants operating to date that can be documented, but Aggreko reported interest from upstream clients – mainly for battery storage systems that can add flexibility to small scale gas engine/microturbine power supply.[5] **Notable about this technology:** • Able to increase the flexibility of small-scale gas engines or microturbines to handle variable loads, thereby removing one the disadvantages of gas engines with respect to diesel gensets. • Improved exported electricity price due improved flexibility to cope with demand variations. • Well-suited for remote operations (optionally). **Notable limitations:** Battery prices are decreasing steadily, but hybrid system will always represent a more complex system than using a single technology (e.g., diesel genset). This increased complexity may be expected to manifest itself in higher CAPEX and OPEX for hybrid systems.	 *Example of hybrid system: Aggreko HPS3K alternating fuel-to-battery power system allows on-site generators to switch from their daily high-load power capacity demand to a battery source when lower power requirements are needed. The generators could be gas engines running on AG, for example.* Source: Aggreko

Capacity range (MMSCFD)	For gas engine component: 0.04 – 2.1 *(equivalent to 200 kW to 10 MW, where 1MW uses 248 SCM/hr gas or 0.21 MMSCFD)*
Type of product produced	Electricity
Amount of yield per MMSCF gas	For gas engine component: Approximately 4.7 MW electric power
Pre-treatment requirements	For gas engine component: Dehumidification and removal of condensable hydrocarbons from the gas is generally required. Due to the often relatively high content of higher hydrocarbons, a derating of the nominal output may be required. In the case of a high concentration of H_2S, desulphurisation of the gas may also be needed.
Modularity	For gas engine component: The engines are normally installed in containerized units with all peripheral systems (ventilation, silencers, cooling, control room) installed inside or on the roof. For battery component: Highly modular For renewable energy component: Highly modular
Other scalability potential	High potential
Auxiliary/additional utilities required	See Gas engines table for this component of the hybrid system. Integration with renewables and/or batteries will require cabling and a power management system.
Applicability (offshore/ onshore)	Gas engines in a hybrid package with batteries should be applicable both onshore and offshore.
Ambient temperature limitations	For gas engines: high ambient temperatures will cause de-rating and ventilation is required

[5] https://www.greeleytribune.com/2016/09/05/energy-pipeline-tech-talk-converting-flared-gas-to-electricity-at-the-tank-battery/
https://www.comap-control.com/solutions/application/power-generation-from-flared-gas
https://www.comap-control.com/solutions/case-study/bi-fuel-conversion-on-an-oil-rig

Minimum feed pressure required	For gas engine: Feed pressure typically in the range 80-200 psi
Temperature operational range	Moderate temperatures are favored by batteries as they have generally a worse performance at very cold and very high temperature
Other climatic constraints	None
Other carbon footprint/ environmental impacts	A gas engine/battery solution will have a lower carbon footprint than a diesel genset
Safety Concerns	Similar to those of small-scale gas engines
Applicability for CCS/CCUS	Not relevant at this scale
Other considerations	-

3.2 Hydrogen production

Hydrogen production	**TRL: Under development** **API 3** *(Prototype Tested)* **to** **API 5** *(System Tested)*
Overall Description: Natural gas is the most commonly used raw material for producing hydrogen, but this is done at downstream refining facilities and not at upstream oil fields. The reason for this is that hydrogen gets produced at the locations it is needed for other processes in order to avoid the complex and expensive challenges of transport. There is no demand for hydrogen at oil field locations and hence it has not been produced there up until now. The concept with this new technology suggestion is to monetize excess AG by converting it into hydrogen prior to transport to market. There are three main methods to convert the methane component of natural gas or AG to hydrogen: steam methane reforming (SMR), methane pyrolysis and partial oxidation. SMR is currently the cheapest and most common method but produces carbon dioxide emissions as a by-product that then require CCS in order to mitigate. The SMR units are typically equipped with hydrogen purifiers to remove nitrogen and CO_2 from the produced hydrogen. Suppliers typically offer pre-reformer units to convert heavier hydrocarbons (if they are in high proportions in the feed natural gas) to methane before feeding to the SMR unit. Regardless of the production technology, the hydrogen produced from AG requires transport to market and this can also take a number of forms, including gas form (high-pressure cylinders), liquid form (cryogenic liquid hydrogen), and solid hydride. Hydrogen liquefaction and solid hydride production would lead to significant additional costs. Nevertheless, in some cases, some or all of the produced hydrogen may be used locally to reduce/eliminate transport costs. For example, if the pipeline gas properties allows, hydrogen may be blended in the gas pipeline (up to ~30%), blended with fuel gas (roughly up to 30%) for usage in the gas turbine for power generation thus reducing the carbon footprint. **Notable about this technology:** • Generate hydrogen as high-value final product • Although hydrogen production generates CO_2 process emissions, combusting H_2 as a fuel has zero carbon emissions. Therefore, if a CCS unit is added at hydrogen production plant, it can theoretically reach a zero-emission fuel. **Notable limitations:**	 *Mini-scale hydrogen unit from natural gas. Photo from Hygear*

• Challenging to transport in gas form from remote locations. Costly to liquify. Moreover, transformation to "energy vectors" like NH_3 or methanol may not be sustainable due to the limited quantities of produced H_2. • Low tolerance to impurities and heavier hydrocarbons (specifically H_2S, C_2, C_3, C_4, C_5+…). For C_2+, a pre-reformer could be used. • Generally capital intensive.	
Capacity range (MMSCFD)	Suppliers such as Hygear offer very small units (less than 0.1 MMSCFD capacity) to multi-MMSCFD. Other supplier such as JGC offer units above 10 MMSCFD capacity.
Type of product produced	Hydrogen gas, Liquid hydrogen, Hydride
Amount of yield per MMSCF gas	Hygrear and JGC claim that up to 2 MMSCF of hydrogen per MMSCF of feedgas (after pretreatment on pre-reforming) can be yielded.
Pre-treatment requirements	H_2S removal is required (max tolerable is less than 0.05 mole%) Pre-reforming of NGLs needed to remove heavier components (dependent on technology provider, less than 3%-5% C_3+ is tolerable). Some suppliers state that H_2O removal is required, but others state that no water removal from the feedgas is required.
Modularity	Most suppliers offer modular units that can be deployed in parallel. Hygrear specified that their units can operate at as low as a 10% load factor.
Other scalability potential	
Auxiliary/additional utilities required	Clean water (at "Boiler Feed" grade) as feed for generating the steam (estimated at 25-35 SCM/tonne of H_2). Electricity needs are at 2-3 MWh per /tonne of H_2
Applicability (offshore/ onshore)	Not tested.
Ambient temperature limitations	The SMR units can operate at -5 to 50 degrees. For lower temperature, housing the units is advised. Cooling kits may be required at higher temperatures.
Minimum feed pressure required	The minimum pressure is typically above 10 bars (depending on the required pressure of hydrogen as a product). Suppliers often offer compressors if the feedgas pressure is below this.
Temperature operational range	Can operate with typical AG temperatures.
Other climatic constraints	-
Other carbon footprint/ environmental impacts	The SMR process generates CO_2 as a by-product that has been conventionally vented to the atmosphere. Typically for 1 kg of produced hydrogen about 10-12 kg of CO_2 is produced. The emissions can be mitigated by deploying CCS. There is a requirement for approximately 0.6 to 0.7 MMSCF of fuel gas for every MMSCF of feedgas.
Safety Concerns	Special safety concerns in case of pressurized hydrogen cylinders. The SMR unit typically has a safety release stack. The stack has to be located at a location with no flame hazard.
Applicability for CCS/CCUS	Applicable but there is an issue with the economy of scale for the very small units, as the amount of CO_2 would be too little to justify a CCS unit.
Other considerations	

3.3 Mini-GTL via syngas production

Mini-GTL	**TRL: Commercial** **API 6** *(Production system installed & tested)* **to API 7 -** *(Production system field proven)*

Overall Description:

Gas-to-liquids (GTL) is the term for the technology to produce synthetic liquid products (diesel, naphtha, kerosene, lubricants, solvents and waxes) from natural gas or associated gas, making the products easier to transport to markets. The conversion of gas to liquids is done by production of synthetic gas ("syngas") as an intermediate; this is called the indirect method.

In the indirect method, syngas (i.e., H_2 and CO) is generated by a process known as reforming. Then the syngas is fed to a catalytic conversion process, e.g., Fischer-Tropsch (FT) process, to generate a liquid hydrocarbon product, also known as synthetic crude. Some technology providers use other catalytic conversion processes than FT for production of synthetic liquids.

These synthetic hydrocarbon liquids often require an upgrading or refining (e.g., cracking) step in order to produce liquid fuels. However, Greyrock state improvements in their catalyst that allows production of liquid fuel requiring only minor processes (e.g., distillation) after catalytic conversion is done.

Notable about this technology:

- Significant increase in product value and marketability.
- Improved possibilities of product transport. (e.g., the product may be blended with oil to use existing oil export pipeline).
- Tech providers claim ability to operate with associated gas volumes as low as under 1 MMscfd.
- Most technology providers offer modular scalable solutions.
- Some tech providers claim the option of remote operations.
- Possibility of remote operation design.

Notable limitations:

- Associated gas requires some pre-treatment, i.e., H_2S removal and C_3+ removal prior to the syngas unit.
- The process is sensitive to impurities such as moisture, CO_2 and very sensitive to H_2S.
- Intensive in energy use. On-site power is required. Tech providers typically offer optional gensets as part of their modules.
- Water supply is required. Significant CO_2 release as the result of catalytic conversion.
- Historically high capital costs (like other GTL/GTC technologies), although costs are lowered in recent years.

Pioneer Energy's mini-scale GTL pilot

A Greyrock Mini- GTL unit

Capacity range (MMSCFD)	Mini-GTL providers offer units for < 1 MMSCFD to multi-MMSCFD plants
Type of product produced	Synthetic diesel, synthetic naphtha, waxes, syncrude.
Amount of yield per MMSCF gas	Up to 100 bbl diesel or syncrude, or e.g., 70 bbl diesel + 30 bbl naphtha.
Pre-treatment requirements	NGL removal is important to increase the efficiency of the process. If necessary, desulphurization of the associated gas is required. Small amounts of CO_2 are tolerable.
Modularity	Yes
Other scalability potential	Units can typically operate at lower load factor.

Auxiliary/additional utilities required	Electricity and heat are required for steam production among other uses. If autothermal reformer (ATR) technology is used, lower energy consumption can be achieved. The ATR however requires air supply which in turn adds to energy intensity. Continuous or occasional water (dependent on the process). Catalysts used in the process are regenerated and sometimes replaced (dependent on the gas quality). Clean water is required. Suppliers typically offer water treatment and recirculation units.
Applicability (offshore/ onshore)	While there is an issue with space and stability, some technology providers claim offshore applicability (no known offshore deployment).
Ambient temperature limitations	Preferred -20 °C to +40 °C. Weatherized shelters can be offered. In case products are cooled by air-cooled heat exchangers, high air temperature can be an issue.
Minimum feed pressure required	Tech providers normally offer compression equipment as part of the design, therefore even low pressure feedgas can be utilized.
Temperature operational range	Typical associated gas temperatures not an issue.
Other climatic constraints	-
Other carbon footprint/ environmental impacts	The syngas production process generates CO_2 as a byproduct. This increases the carbon footprint of the technology. GTL technologies are relatively energy intensive. Carbon efficiency is low relative to other AG utilization technologies
Safety Concerns	-
Applicability for CCS/CCUS	The CO_2 produced as part of the process can theoretically be captured, although it represents a significant economic viability issue in case of small-scale situations, due to low amount of CO_2 generated.
Other considerations	-

3.4 Mini-GTL with direct conversion

Mini-GTL with direct conversion	**TRL: Commercial** *(for natural gas)* **and Under pilot testing** *(for AG)* **API 6** *(Production system installed & tested)* **to API 7 -** *(Production system field proven)*
Overall Description: The direct conversion process converts gaseous hydrocarbons to liquid chemicals without intermediate production of syngas. Several direct methods have been tested, the most developed are direct oxidation of methane to methanol and oxidative coupling of methane. Other direct routes include CH_4 pyrolysis, which is a process that splits natural gas directly into hydrogen and solid carbon at an extremely hot reactor. **Notable about this technology:** • Production of methanol that can be used directly in most oil production facilities (and cut import costs significantly) and is a high-value sales product. • Tech providers claim ability to operate with associated gas volumes of below 0.5 MMSCFD. • As compared to traditional indirect GTL process, use of catalysts are eliminated. • Can process gas high moisture and CO_2 in the feedgas • Possibility of remote operations.	 *Source: GasTechno*

Notable limitations: • Same as indirect GTL, process is sensitive to impurities such as H_2S. • Could be intensive in energy use (dependent on recycle rate), including need for on-site power. Tech providers typically offer optional gensets as part of their modules. • Oxygen supply and on-site power are required. Tech providers typically offer optional genset as part of their modules. • Historically high capital costs, although costs are lowered in recent years (a tech provider claimed success in lowering unit CAPEX to less than half compared to traditional GTL). In cases where ASU is installed, CAPEX increases but OPEX is lowered. OPEX can be high if O_2 cylinders are used.	
Capacity range (MMSCFD)	From below 0.5 MMSCFD to multi-MMSCFD. GasTechno offers units as low as 0.3 MMSCFD, but customized units can be designed.
Type of product produced	Methanol and some formalin, and lesser amounts of ethanol (dependent on the gas composition).
Amount of yield per MMSCF gas	Approximately 0.012 to 0.018 tonnes product (methanol and ethanol) per MMSCF
Pre-treatment requirements	NGLs up to 10% volumetric fraction is tolerable. If necessary, desulphurization of the associated gas is required. Low concentrations of CO_2 are acceptable. H_2O removal is typically not required.
Modularity	Yes
Other scalability potential	Units can typically operate at lower load factor. GasTechno claims that units can operate from 30% to above 100% of nameplate design capacity.
Auxiliary/additional utilities required	Electricity is required the process. The process requires oxygen
Applicability (offshore/ onshore)	No known offshore deployment
Ambient temperature limitations	Preferred -20 °C to +40 °C. Weatherized shelters can be offered. In cases products are cooled using air-cooled heat exchangers, high air temperature can be an issue.
Minimum feed pressure required	The process operates at a very high pressure (about 1000 psi)
Temperature operational range	Typical associated gas temperatures are not an issue.
Other climatic constraints	-
Other carbon footprint/ environmental impacts	Direct conversion GTL technologies are relatively energy intensive, although some energy savings are made with the elimination of the need for syngas generation.
Safety Concerns	-
Applicability for CCS/CCUS	-
Other considerations	-

3.5 Small scale gas engines

<table>
<tr><th>Small scale gas engines</th><th>TRL: Mature & Commercial, TRL 7 (Production system field proven)</th></tr>
<tr><td>Overall Description:
Small-scale gensets use reciprocating engines to spin the generator, which in turn produces electricity. Gas engines can be deployed as an alternative to diesel gensets to avoid the need for diesel transportation and storage, particularly at remote locations.

The composition of associated petroleum gas is often well suited as a fuel for gas engines, although some pre-treatment may be required. Depending on local demands, the waste heat from the engines can also be used for heating or cooling purposes on site – so called combined heat and power (CHP).

Small gas engines, suitable for handling below 0.1 to 2 MMSCFD of AG, with possibility of modular installation for larger volumes are robust, heavy-duty internal combustion engines integrated with an electrical generator. Dependent on the gas composition (methane number) and pre-treatment applied, under favourable conditions electrical efficiency may reach to more than 40% – on a par with larger gas turbines.

Notable about this technology:
• Can replace the need for diesel supply and storage for power generation
• Dependent on the gas quality, an overall efficiency of above 60%, in the case of combined heat and power, and above 45% in the case of power generation only.
• Flexible with regards to the methane number of the gas (rich or lean).
• Operable with high C_3, C_4, CO_2 and N_2 content.
• Turn-key container solutions allow for fast installation.

Notable limitations:
• Low methane number, both due to high CO_2 content or high C_2-C_4 content, has an impact on the output. Lower heating value should be above 750 BTU/SCF, although it may be possible to operate an engine below even this limit, but performance will be impaired.
• Flexibility: One disadvantage of gas engines compared to diesel engines is their relative inflexibility dealing with load fluctuations (lowest 40% load factor)[6].
• NO_x emissions: gas engines will normally require selective catalytic reduction (SCR) of the exhaust gases in order to remove these emissions.</td><td>
Jenbacher-3-Series supplied by Clarke Energy
https://www.clarke-energy.com/us/gas-engines/type-3-gas-engines/jenbacher-3-series/


www.aggreko.com</td></tr>
<tr><td>Capacity range (MMSCFD)</td><td>0.1 MMSCFD for 300-500 kW capacity engine (dependent on the gas composition), 1 MMSCFD for ~3-5 MW capacity engine (dependent on the gas composition).</td></tr>
<tr><td>Type of product produced</td><td>Electricity and heat (optional)</td></tr>
<tr><td>Amount of yield per MMSCF gas</td><td>Between 90 to 150 MWh electric power per MMSCF of feed dependent on the AG composition and engine efficiency</td></tr>
<tr><td>Pre-treatment requirements</td><td>Dehumidification and removal of condensable hydrocarbons (C_5+) from the gas is generally required. Due to the often relatively high content of higher hydrocarbons, a derating of the output may be required if methane number is too low (i.e., reduced efficiency). In the case of a high concentration of H_2S, desulfurization of the gas may also be needed.</td></tr>
</table>

[6] A new development is to address this limitation by combining battery storage with gas engines in order to create a hybrid system (see Hybrid Solutions for more details).

Modularity	The engines are normally installed in containerized units with all peripheral systems (ventilation, silencers, cooling, control room) installed inside or on the roof. Modularity is possible.
Other scalability potential	Large choice of individual engine size. Common practice to install multiple engines in parallel. Scalability is partial, since the load factor generally cannot be lower than 40%, otherwise the engine must be shut down.
Auxiliary/additional utilities required	According to one supplier stand-by pumps, central coolers, starting air vessels, lubricating oil automatic filters, exhaust gas silencers and boilers are typically delivered for separate mounting[7]
Applicability (offshore/ onshore)	Not common for offshore applications, due to stricter installation rules and space problems.
Ambient temperature limitations	None. Implementation in Arctic climates as well as in hot desert areas are reported. High ambient temperatures will cause de-rating and ventilation is required
Minimum feed pressure required	Feed pressure can be as low as under 1 bar
Temperature operational range	Typical associated gas temperatures are not an issue.
Other climatic constraints	None
Other carbon footprint/ environmental impacts	Filters / catalysts may be required to reduce sulfur oxides and nitrogen oxides emissions. CO_2 emissions (that would be otherwise also emitted in case of flaring).
Safety Concerns	Operations in ATEX zones 0, 1 and 2 (i.e., areas in which an explosive gas atmosphere is present continuously, or for long periods or likely to occur in normal operation or even if they exist occasionally for a short time) are not safe. Spark arrestors and unit enclosures with ventilation are typically designed.
Applicability for CCS/CCUS	At mini-scales carbon capture is not possible due too low CO_2 stream for capture technologies. At larger scales, CCS is possible but would be very expensive to capture due to low amounts of CO_2.
Other considerations	-

3.6 Scaled Gas Processing Unit and NGL Recovery

Scaled Gas Processing Unit and NGL Recovery	**TRL: Mature & Commercial, TRL 7** *(Production system field proven)*
Overall description: Gas processing equipment separates NGLs from AG to produce ethane, LPG, C_5+ and natural gas streams (propane and butane streams can also be separated through fractionation). Ethane, LPG and C_5+ hydrocarbons are then transferred to storage facilities and sold, while natural gas may be either sent to flare or utilized. **Notable about this technology:** Scaled gas processing and NGL recovery is perfectly suited for remote site deployment far from infrastructure and for all fields with short or long remaining field life (since equipment is easily re-deployable after end of field life). This technology may be particularly attractive where local markets exist for NGL products and where road or rail infrastructure exists for product evacuation. In addition, in case marketing of individual products such as LPG and condensate is challenging or uneconomic due to the lack of transport	*AG processing and NGL recovery unit based on the technology of AEROGAS LLC, operating at the Dobrinskoye field of Volga Gas (Russia)*  *Source: AEROGAS LLC, Skolkovo*

[7] https://www.wartsila.com/marine/build/engines-and-generating-sets/wartsila-engines-auxiliary-systems

<table>
<tr>
<td colspan="2">infrastructure or potential consumers, they can often be blended into the crude oil stream.

Notable limitations:

Outside of the economic efficiency of a small-scale gas processing plant, which is dependent on a number of factors, including the AG composition (high content of NGLs is preferable) and the location of the field (in terms of availability of transport infrastructure and a market for the produced NGLs), no substantial limitations to the deployment of this technology for AG utilization have been identified. However, the following must be considered:
With a high content of hydrogen sulfide and mercaptans, a desulfurization unit is required. The maximum H_2S content varies depending on the technology provider.
CO_2 must also be removed in most cases: while CO_2-tolerant designs can withstand up to 0.5% of carbon dioxide, this limit is lower for other types of equipment.
Water must be separated from feed gas prior to NGL extraction. Technology providers highlight that in case of high water content, its management may be a substantial challenge and may require the installation of several skids.
In the case of offshore applications, the main limitation is the availability of space on the platform.</td>
<td></td>
</tr>
<tr>
<td>Capacity range (MMSCFD)</td>
<td colspan="2">The technology can be implemented at new or mature fields with a wide capacity range.

The minimum capacity offered by technology providers is usually 0.5-0.7 MMSCFD, although smaller solutions are also available. In particular, Pioneer Energy offers a Flarecatcher 400-65 unit with the processing capacity of 400 MSCFD.[8] The company also notes that the equipment is capable of operating at no flow, therefore technical limitations in terms of the minimum AG production volume are virtually non-existent.

It should be noted that the “typical” capacity of a utilization project can be substantially higher than required by the feedgas volume as the equipment generally comes in standard sizes.

The scalability potential of the technology is substantial since maximum capacity can be increased through the construction of additional trains, therefore there are virtually no restrictions in terms of the maximum volume of AG processing.

GazSurf LLC and other technology providers note that the minimum economically-justifiable scale of a processing and NGL recovery unit is largely determined by the composition of AG. In particular, units of very small capacity may only be viable in the case of rich gas.</td>
</tr>
<tr>
<td>Type of product produced</td>
<td colspan="2">In general, AG processing and NGL recovery units allow to produce separate ethane, LPG, C_5+, and natural gas streams (propane and butane streams can also be separated by fractionation) depending on the composition of the installed equipment.

The range of products at an individual unit will depend upon the composition of AG, the availability of a market for the product in question and economic feasibility of its recovery.</td>
</tr>
<tr>
<td>Amount of yield per MMSCF gas</td>
<td colspan="2">Product yield depends on feed gas composition and the efficiency of the NGL recovery process (which depends on the technology provider and may vary from 25% to 100%). Thus, given the typical composition of lean associate gas 1 MMSCFD may yield up to 0.77 MMSCFD of methane, 0.13 MMSCFD of ethane, 0.07 MMSCFD of LPG (propane, isobutane and n-butane), 0.02 MMSCFD of C_5+ hydrocarbons.</td>
</tr>
</table>

[8] Pioneer Energy. Flarecatcher 400-65 Specifications sheet. Pioneer Energy official website. Available at: https://www.pioneerenergy.com/sites/570fd5172c1cc42da4030bf9/content_entry57574a755918ad1f9837958e/57574f7f5918ad1f9837c81d/files/Flarecatcher_400-65_-_Spec_Sheet.pdf?1566097423

	It should be noted that the rate of recovery of NGLs depends primarily upon the economic efficiency and feasibility, since achieving a higher recovery rate requires high capital and operating costs. According to AEROGAS LLC, the "typical" industry average level in Russia is extraction of 70-75% of LPGs and 95% of C_5+ hydrocarbons. Pioneer Energy also confirms that virtually up to 100% of NGLs can technically be extracted, however the most economically effective rate of recovery will vary substantially across regions depending primarily upon the composition of AG.
Pre-treatment requirements	There are no restrictions on the composition of AG. However, with a high content of hydrogen sulfide and mercaptans, a desulfurization unit is required. The maximum H_2S content varies depending on the technology provider. In particular, Aspen Engineering Services notes that their equipment can tolerate up to 2-3% of H_2S, while other technology providers indicate that their products can handle up to to 20 ppm or about 0.25% of H_2S. Pioneer Energy points out that, even if the supplied equipment is able operate with high sulphur content, its recovery may still be required in order to achieve the desired product quality. CO_2 must also be removed in most cases: while CO_2-tolerant designs can withstand up to 0.5% of carbon dioxide[9], this limit is even lower for other types of equipment. Pioneer Energy also highlights that water separation is required and frequently comes as a standard product offering. In case of high water content, its management may be a substantial challenge and may require the installation of several skids. For deep NGL recovery processes (where the temperature reaches -100°C) a residual water content lower than 0.1 ppmv is required.[10] For the processes that occur at higher temperatures (e.g. fractionation) the maximum allowed water content is substantially higher.[11]
Modularity **Other scalability potential**	Modular and scalable (skid-mounted or containerized) units for NGL recovery are available and supplied by various technology providers, including AEROGAS LLC, Pioneer Energy, GazSurf LLC, Aspen Engineering Services. The units can be re-positioned after field life for re-use elsewhere. Lifetime of the processing units may vary as per manufacturer specifications.[12] Pioneer Energy notes that modular solutions with the capacity of 15+ MMSCFD can be viable. However, in case of higher production volume (particularly 60+ MMSCFD), conventional non-modular plants tend to be the more effective option. According to AEROGAS LLC, their clients are highly interested in mobile units due to the economic benefit associated with the possibility of their relocation to other fields, which is particularly important in the case of assets with a short life span and / or small AG reserves. Application of design solutions that enable compact designs, such as the use of in-line separators[13], enable supply of such units. However, in some countries and, in particular, in Russia, there are certain legal barriers to the implementation of mobile AG processing and NGL recovery plants, associated with the need to "bind" the installations to a specific location. For this reason, there are currently no examples of deployment of mobile units in Russia. In this regard, when considering the possibility of deployment of mobile equipment, not limited to gas processing plants, the specifics of national legislation must be taken into account.

[9] Linde (2019) Natural Gas Processing Plants. Extracting maximum value from natural gas, p. 11. Available at: https://www.linde-engineering.com/en/images/Natural-gas-processing-plants_2019_tcm19-4271.pdf
[10] Siirtec Nigi. Gas Dehydration and Hydrates Control. Available at: https://www.siirtecnigi.com/design-gas-dehydration
[11] H. Paradowski, A. Le-Gall & B. Laflotte (2005) Compare the different options for NGL recovery from natural gas, p. 8. Available at: http://www.ivt.ntnu.no/ept/fag/tep4215/innhold/LNG%20Conferences/2005/SDS_TIF/050215.pdf
[12] GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. Gas processing, pp. 5-14. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf
[13] An in-line separator separates the bulk of the incoming natural gas, and therefore makes it possible to either completely abandon the application of a capacitive separator, which, as a rule, is a rather large-sized structural element, or allow to make it significantly smaller in volume, which significantly reduces the size of the processing unit as a whole.

Auxiliary/additional utilities required	AG processing units require a power supply to operate. While the availability of existing infrastructure is preferable, it is possible to self-generate the electricity on-site. GazSurf LLC notes that gas-driven generating equipment typically consumes about 300-350 SCM (10.6-12.4 MSCF) per MW of capacity, which amounts to about 8-12% of feed gas. Other technologies may however require less power. According to Aspen Engineering Services, the company's solutions based on the NGL Pro process, consume about 5% of feed gas generating electricity. This is due to the fact that the provider's technology does not require artificial cooling or mechanical refrigeration. Transport infrastructure is also required for product evacuation. In addition, nitrogen may be required as a blowdown gas, which is widely used in the oil and gas industry to ensure explosion safety.[14]
Applicability (offshore/ onshore)	AG processing units can be deployed both onshore and offshore.[15] In the case of offshore applications, the main limitation is the availability of space on the platform.[16] As noted above, compactness of the AG processing units can be achieved through application of certain design solutions, such as the use of in-line separators. According to Aspen Engineering Services, the size of compressors must also be considered. GazSurf LLC also notes that the compactness of equipment and increased requirements for reliability associated with offshore applications tend to significantly increase the capital costs of AG processing and NGL recovery units. Pioneer Energy points out that the company's solutions are compact enough and can be used offshore. Such equipment, however, slightly differs from the products intended for onshore use, in particular marine-grade paint is applied.
Ambient temperature limitations	As noted by AEROGAS LLC, the company successfully applies its solutions in various climatic zones, including the regions where the ambient temperature, depending on the season, ranges from -60°C to +50°C. Examples include the processing plants implemented at the S. Balgimbaev field in Kazakhstan (hot climate) and in Yakutia in Russia (cold climate). There are therefore practically no restrictions on the ambient temperature. However it is important to note that, since the processes for separating NGLs are typically associated with cooling, a processing plant located in a warm climate, other things being equal, would be less efficient. This is confirmed by technology providers, including GazSurf and Aspen Engineering Services. As noted by GazSurf LLC, deployment in a very cold environment requires the use of special steel in the manufacturing of equipment, as well as additional maintenance.
Minimum feed pressure required	Minimum required inlet feed pressure varies depending on the technology provider, however it should be noted that some of them, including Pioneer Energy, GTUIT and MTR, offer equipment that can accept feed gas at virtually no pressure. The solutions of other suppliers may require a minimum inlet pressure in the range of 25-75 psi.[17]

[14] S. Mikhalev, A. Platonov, A. Grishina. Technical and economic aspects of determining the concentration of gaseous nitrogen required to ensure explosion safety. [In Russian] Available at: https://www.ukz.ru/stati/tehniko-ykonomicheskie-aspenkty-opredeleniya-koncentracii-gazoobraznogo-azota-neobhodimoi-dlya-obespecheniya-vzryvobezopasnosti/

[15] GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. Gas processing, pp. 5-14. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf

[16] Boffelli, G.A.D., Mendoza, A.L. & Ramirez, J. (2020) NGL Recovery at the Gulf of Mexico: A Profitable Strategy at Offshore Facilities, p. 4.

[17] GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. Gas processing, pp. 5-14. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf

	Pioneer Energy also points out that the "sweet spot" that ensures the optimal performance of the equipment is the inlet pressure of 450 psi. Some technologies may require higher pressure to operate. In particular, some processes require a minimum pressure differential of 600-800 psi, while variability of feed is not an issue. If necessary, the pressure required can be achieved through the use of a compressor.
Temperature operational range	The temperatures vary substantially throughout the process. In particular, the fractionation typically occurs at -35 to -25°C, while cryogenic processes that are required for production of ethane imply the temperature range of -120 to -110°C. AEROGAS LLC notes that operating temperatures are important to the process since non-optimal conditions may result in lower NGLs extraction efficiency, however they are not critical to the application of the technology. The required temperatures can be achieved by installation of the necessary equipment, such as air-cooling units or heat exchangers.
Other climatic constraints	Pioneer Energy points out that in addition to the ambient temperature there are several other environmental conditions that may affect the performance of the equipment. In particular, high altitudes are undesirable. Humidity and rain conditions should also be taken into consideration.
Other carbon footprint/ environmental impacts	Implementation of the technology reduces negative environmental impacts by reducing flare volumes. However, it should be noted that AG processing and NGL recovery plants generate a certain amount of emissions due to combustion of about 5-12% of AG for powering the equipment. The intensity of such emissions depends on the compositions of the feed gas.
Safety concerns	As noted by the technology providers, the operations of AG processing and NGL recovery units are not associated with substantial safety risks. This is due to the fact the technology is mature and the manufacturing of the necessary equipment is subject to rigorous national standards and regulations. In addition, Aspen Engineering Services highlights that certain risks may be associated with elevated pressure in the equipment that is required for NGLs extraction (as is the case with any technology that involves high pressure levels), although the supplied units are typically explosion-proof and incudes several safety systems, including alarms and telemetry. The absence of substantial health and safety risks is also confirmed by Pioneer Energy. The company notes that safety is the focus of the production design and numerous automated safety systems are in place, including gas sensors to detect leaks.
Applicability for CCS/CCUS	CCS technology has already been successfully implemented at several large-scale gas processing facilities. Notable examples include Century and Val Verde Gas Plants in Texas, In Salah plant in Algeria, Gorgon injection project in Australia, and others.[18] As noted by technology providers, while the application of CCS/CCUS technologies is theoretically possible in the case of small-scale facilities, it is typically economically unviable. Examples of laboratory and field-tested CCS technologies that currently await commercial deployment and can technically be applied to small-scale processing plants include: ▪ DDR membrane process that is a high-efficiency CO_2 separation technology using a DDR-type zeolite membrane. It is suitable for CO_2 separation from associated gas deriving from CO_2-EOR and natural gas with high CO_2 content[19];

[18] Carbon Brief (2014) Around the world in 22 carbon capture projects. Technology section. October 7. 2014. Available at: https://www.carbonbrief.org/around-the-world-in-22-carbon-capture-projects
[19] JGC Holdings Corporation. DDR Membrane - CO_2 Separation for Natural Gas Treatment. Available at: https://www.jgc.com/en/business/tech-innovation/environment/ddr-membrane.html

	▪ HiPACT process that recovers CO_2 at high pressures from natural gas and synthesis gas.[20] It is also important to note that the technologies offered by the technology providers can be used to dry the CO_2 before it is injected into the reservoir. Such solutions are currently used, in particular, by AEROGAS LLC. The potential for the application of the technology for enhanced oil recovery is also highlighted by Aspen Engineering Services. Pioneer Energy also points out that the equipment can be used to liquefy CO_2.
Other considerations	1) There are various methods for NGL recovery, these include the solutions that apply refrigeration units, and the technologies based on pressure differentials. The former are more widespread in Western countries, while the latter are more common in Russia and the CIS region. 2) Some technologies allow to return the weathering gas (i.e. gas released from the liquid phase), which is rich in NGLs and is typically directed to the flare, back to the process, thus increasing the overall NGL extraction rate.[21] 3) As noted by Pioneer Energy, standardized AG processing and NGL recovery units tend to be cheaper and faster to supply, however customized solutions may be a better option as they may increase the product yield significantly.

3.7 Microturbines and Small-Scale Gas Turbines

Microturbines and Small-Scale Gas Turbines	**TRL: Mature & Commercial, TRL 7** *(Production system field proven)*
Overall description: Microturbines are small combustion turbines with outputs of 25 kW to 500 kW[22] (while conventional gas turbine sizes range from 500 kW to 350+ MW). In the microturbines, combustion gases are used to spin the turbine, which in turn spins the electrical generator to produce electricity. Like larger gas turbines they can be used in power-only generation or in combined heat and power (CHP) systems. Gas turbines of higher capacity, e.g. 1.8 MW models provided by OPRA Turbines, are also applicable for small-scale AG utilization projects and will also be covered in this section, although it should be noted that due to the differences between microturbines and small-scale gas turbines, they will be considered separately where applicable. Depending on the technology provider, microturbines and small-scale gas turbines may be able to operate on a variety of fuels, including natural gas, sour gases (with high H_2S content), low heating value gases, and liquid fuels such as gasoline, kerosene, and diesel fuel / distillate heating oil, gas	*C200S 200 kW microturbine by Capstone Green Energy*  *Source: Capstone Green Energy* *OP16 gas turbine produced by OPRA Turbines*

[20] JGC Holdings Corporation. HiPACT - an Innovative CO_2 Capture Process. Available at: https://www.jgc.com/en/business/tech-innovation/environment/hipact.html

[21] As part of the low temperature separation process, raw gas from the wells enters the inlet separator, where the liquid phase is separated. After cooling, the gas enters a low-temperature separator, where condensed liquid hydrocarbons and an aqueous solution of a hydrate inhibitor are separated from the gas stream. The liquid phase from the low-temperature separator is heated in a recuperative heat exchanger and then enters a three-phase separator, from where the weathering gas that is rich in NGLs is usually sent to a flare. At the same time, some types of equipment, in particular the technologies supplied by GazSurf, allow to direct this weathering gas back into the process, and extract the NGLs from it.
Source: GazSurf (2021) Low temperature separation method. GazSurf official website. [In Russian] Available at: https://gazsurf.com/ru/gazopererabotka/stati/item/metody-podgotovki-prirodnogo-gaza-k-transportirovke-v-truboprovode

[22] Barney L. Capehart (2016). Distributed Energy Resources (DER). Microturbines. Whole Building Design Guide. National Institute of Building Sciences. Available at: https://www.wbdg.org/resources/microturbines#:~:text=Microturbines%20are%20small%20combustion%20turbines,airplanes%2C%20and%20small%20jet%20engines.

<table>
<tr>
<td colspan="2">condensate and pyrolysis oil. They are widely used for autonomous heat and power generation, particularly in the oil and gas sector.

Notable about this technology:

Microturbines technology is mature and has been successfully applied in different regions for autonomous heat and power generation for about two decades. This is also applicable to turbines of higher capacity. According to OPRA turbines, their products are used widely in small-scale CHP (combined heat & power applications) because of their low maintenance requirements, low emissions and lower noise levels.

In contrast to reciprocating gas engines, microturbines and small-scale gas turbines tend to be less demanding in terms of feed gas quality. In particular, the products of Capstone Green Energy and OPRA Turbines can tolerate up to 3% and 4% of H_2S content respectively.

In addition, the solutions of OPRA Turbines are capable of operating on AG with constantly changing composition, which the company sees as a major competitive advantage.

Due to a more compact size, microturbines are better suited for offshore locations in comparison to other power generation solutions.

Notable limitations:

The key limitation to the implementation of this technology at an individual field is typically insufficient on-site demand and the absence of potential consumers. This issue, however, can be resolved by the creation of an energy-intensive facility close to the field, such as a data center (see details in the Data Centers section of this report).

In addition, although microturbines and small-scale gas turbines are quite flexible in terms of AG composition and properties in comparison to other power generation solutions, these aspects still must be considered since some technology providers have feed gas specification for their equipment that, as a result, may require pre-treatment. This limitation, however, is not universal. In particular, OPRA Turbines notes that their products are capable of operating on AG with constantly changing composition, which the company sees as a major competitive advantage.

In comparison to reciprocating gas engines, microturbines are more costly.</td>
<td>
Source: OPRA Turbines</td>
</tr>
<tr>
<td>Capacity range (MMSCFD)</td>
<td colspan="2">There is virtually no minimum volume of feedgas required as gas turbines can operate at a fraction of their design capacity. E.g., some of the technology providers note that their gas turbines can run at a load factors as low as 5%.

Typical capacity range of microturbines

As noted above, microturbines are usually defined as small combustion turbines with outputs of 25 kW to 500 kW. The range of a major supplier – Capstone Green Energy – includes models with capacity from 65 kW to 1 MW (which consists of five 200 kW microturbines packaged in a single enclosure).

Microturbines have substantial scalability potential. Capstone Green Energy notes that projects with the total capacity of 5 MW have been implemented. The company also highlights that the amount of consumed AG depends upon its composition with fuel mass flow rates being higher for lower energy fuels. The 65 kW model offers a net heat rate of 12.4 MJ / kWh, and the 200-1000 kW models offer 10.9 MJ / kWh.

Typical capacity range of small-scale gas turbines

Typical capacity of products supplied by OPRA Turbines delivers up to 1.8 MW of electricity and up to ~4.5 MW of heat/ 6 tons of steam per hour, which brings the total fuel efficiency up to 93%. The scalability potential allows to install a power plant with total capacity up to 20 MW.

The net heat rate of the 1.8 MW turbine amounts to 14.4 MJ / kWh.[23]</td>
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[23] OPRA Turbines (2021) Technical parameters of OPRA OP16 gas turbine unit. OPRA Turbines official website. Available at: https://www.opraturbines.com/wp-content/uploads/2020/07/OPRA_Technical_Leaflet_Russian.pdf

	Consumption of AG per MW may vary depending on its properties and energy content, as well as on the technology provider. According to OPRA Turbines, its 1.8 MW OP 16 model consumes between 550 and 2500 NCM per hour, which translates to about 0.47 to 2.12 MMSCFD, i.e. 0.26 to 1.18 MMSCFD per MW. The fact that the provided range is so wide is due to the ability of OPRA Turbines' equipment to operate on feed gas with very low heating value.
Type of product produced	Depending on the generation mode and type of equipment gas turbines may produce: ▪ Only electricity; ▪ Electricity and power in the CHP mode. In addition, Capstone Green Energy highlights that exhaust gases of its microturbines can also be utilized. In particular they can be used to yield: ▪ 250 kg/hour of steam at 8 Bar (g) in case of a 200kW model; ▪ Up to 180 kW-thermal of hot water in case of a 65kW model, which can be used, for example for crude oil heating Exhaust gases of Capstone Green Energy's products can also be used for absorption chilling.
Amount of yield per MMSCF gas	**Yield per 1 MMSCFD for microturbines** Assuming that a microturbine runs on natural gas with an average heat value of 48.5 MJ/kg[24] and density of 0.68 kg/SCM, 1 MMSCFD can yield from 27.5 to 31.3 GWh of energy annually. When run on lean AG, this value decreases by about 1.3 times. **Yield per 1 MMSCFD for small-scale gas turbines** Given the aforementioned assumptions and the net heat rate of 14.4 MJ / kWh, gas turbines can generate about 23.7 GWh of energy annually per 1 MMSCFD of feed gas.
Pre-treatment requirements	**Microturbines** According to Capstone Green Energy, AG must be conditioned in order to meet the feed gas specification requirements. In particular, AG must be superheated 15°C above the dew point at the fuel supply pressure, which ranges between 65 to 75 psig depending on the model type. Contaminants and NGLs may also need to be removed. At the same time, microturbines in general tend to be less demanding to the quality of the feed gas in comparison to other power generation solutions and have significant tolerance to contaminants such as H_2S, SO_2 and N_2. For example, the products of Capstone Green Energy allow the content of H_2S, CO_2 and N_2 – of up to 3%, 70% and 22% respectively.[25] **Small-scale gas turbines** Feed gas specification may vary depending on the technology provider and pre-treatment requirements are not universal. In particular, AG must be treated in the case of multi-shaft turbines. At the same time certain technology providers offer less demanding equipment. E.g., single-shaft turbines supplied by OPRA Turbines require only a scrubber, gas dehydration and allow the maximum content of H_2S + Cl (chlorine) content of up to 4%.
Modularity	Modular and scalable solutions are available.
Other scalability potential	**Microturbines** According to Capstone Green Energy, the microturbines have built in functionality for operating multiple systems in parallel. External controllers are also available to operate microturbines in groups with different dispatch modes. Pre-packaged 600

[24] World Nuclear Association (2021) Heat Values of Various Fuels. World Nuclear Association official website. Available at: https://world-nuclear.org/information-library/facts-and-figures/heat-values-of-various-fuels.aspx
[25] GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. Power Generation, p. 18. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf

	kW and 800 kW systems provided by the company can be offered in enclosures with extra slots for scaling up in 200 kW increments up to 1000 kW. **Small-scale gas turbines** Solutions provided by OPRA Turbines are available in containerized configuration.
Auxiliary/additional utilities required	Utilities are not required, microturbines and small-scale gas turbines are fully autonomous. In addition, Capstone Green Energy notes that microturbines are completely dry systems that require no liquid coolants, lubricants or grease for operation and use air bearings and air cooling systems for higher availability and reliability.
Applicability (offshore/ onshore)	Both microturbines and small-scale gas turbines have been successfully deployed offshore, as well as onshore. **Microturbines** Capstone Green Energy highlights that microturbine systems have already been deployed to utilize AG on offshore oil platforms around the world. Microturbines are also used on offshore gas wellhead platforms to operate on the wellhead gas to minimize the requirement of diesel. In particular, microturbines have been successfully deployed at offshore facilities in China and Myanmar. **Small-scale gas turbines** OPRA Turbines indicates that the company's products have been successfully installed at offshore platforms and, provided sufficient space is available, there are no installation issues.
Ambient temperature limitations	Both microturbines and small-scale gas turbines have been successfully implemented in various climatic conditions. **Microturbines** Capstone Green Energy notes that the standard microturbine package has operating limits between -20℃ and +50℃. However, special weather packaging is also available to extend this range to extreme conditions. In particular, microturbines have been deployed in arctic and desert environments. **Small-scale gas turbines** According to OPRA Turbines, the typical ambient operating temperatures range from -60℃ to +45℃. Either Arctic or Tropical kit may however be required in some locations and conditions.
Minimum feed pressure required	Gas inlet pressure of microturbines and small-scale gas turbines may vary depending on the technology provider. **Microturbines** Fuel supply pressure of microturbines produced by Capstone Green Energy is limited to between 65-75 psig depending upon the model type and characteristics of the proposed fuel. In addition, Capstone Green Energy's products are capable of tolerating a ±10% variability of fuel feed, although this figure may differ for the products of other technology providers. While highly unstable fuel feed has an unfavorable impact on performance, it is not critical. **Small-scale gas turbines** Gas turbines supplied by OPRA Turbines require a fuel inlet pressure of 170-230 psig.
Temperature operational range	The process of generating heat and electricity involves high temperatures and the temperature of exhaust gases of small turbines typically reaches about 425-480℃.[26] This range, however, may vary depending on the technology provider.

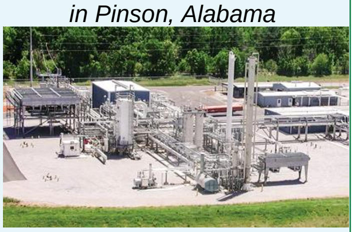
[26] Energy Solutions Center. Understanding CHP. 4.3. Gas Turbines. 4.3.1 Technology Description. Available at: https://understandingchp.com/chp-applications-guide/4-3-gas-turbines/#:~:text=Gas%20turbine%20exhaust%20is%20quite,direct%20use%20of%20the%20exhaust.

	In particular, according to Capstone Green Energy, exhaust flue gas temperatures of its microturbines are expected to be around 280-309℃ depending upon the ambient conditions and output demand, while for the products of OPRA Turbines the temperature of exhaust gases reaches 570℃.
Other climatic constraints	Gas turbines operate successfully under various climactic conditions. No significant modifications are required to adapt a gas turbine to an extremely cold or hot climate. However, it should be noted that the performance of microturbines and small-scale gas turbines can be adversely affected at high altitude.
Other carbon footprint/ environmental impacts	Since microturbines and small-scale gas turbines are combustion-based technologies, the use of hydrocarbons as fuel will result in the production of CO_2, CO and NO_x. Exact greenhouse gas emissions will depend upon the fuel used to operate the system. Capstone Green Energy notes that its products achieve 99+% combustion of hydrocarbons which exceeds the performance of gas reciprocating units and the environmental impact compared to venting or incomplete combustion technologies. Assuming that a microturbine is run on pure methane, the exhaust gases (0.49 kg/s in case of a 65 kW model and 1.33 kg/s for a 200kW model) would contain 2.3 mass % of CO_2 and 1.3 mass % of trace elements. The company highlights that its CARB[27] certified products offer ultra-low CO (8 ppmv) and NO_x (4 ppmv) emissions.[28] The company also notes that its microturbines offer good performance in terms of lifecycle emissions since they require no lubricants, coolant or exhaust gas after-treatment. In addition, since the microturbines offer high reliability, they demand only two service visits per year, thus allowing to make the installation normally unmanned and avoid emissions, as well as the operating costs, associated with personnel visits. In case of remote fields, the reduction in costs and emissions may be particularly significant. OPRA Turbines also notes that it offers low-emission turbines with particular focus on environmental performance. In particular, the company provides gas turbines that allow to achieve emissions of 0.85 mg of CO and NO_x per SCF. Application of microturbines and small-scale gas turbines allows to make beneficial use of AG that would otherwise be flared. The major advantage of this method is the ability to displace generating facilities that have higher carbon-intensity, such as diesel generators, that are commonly used at remote locations.
Safety concerns	No significant operational safety issues and concerns were identified, apart from high temperature of exhaust gases. Both microturbines and small-scale gas turbines operate using robust, proven technology. Numerous systems have been deployed worldwide and have been successfully operating for decades with no major issues. Capstone Green Energy notes that the solutions provided by the company have UL[29], CE[30] and other third-party compliance certifications to meet various regulatory requirements for combustion-based power generating technologies. It should also be noted that certain modifications of small-scale gas turbines are highly resilient to seismic activity, e.g. OPRA Turbines offers solutions that can withstand seismic activity up to 9 on the Richter scale.
Applicability for CCS/CCUS	Potential for applicability of CCS/CCUS technologies is limited in the case of combustion-based power generating technologies since little options exist for extraction of carbon.

[27] California Air Resources Board.
[28] Capstone Green Energy (2008) Technical Reference. Capstone MicroTurbine System Emissions. 410065 Rev. B (April 2008), p. 3.
[29] UL, formerly known as Underwriters Laboratories, is a global safety certification company.
[30] CE marking is an administrative marking with which the manufacturer or importer affirms its conformity with European health, safety, and environmental protection standards for products sold within the European Economic Area.

Other considerations	According to Capstone Green Energy, the company's products only have one moving part and are characterized by high reliability and very low downtime, in particular only 6 hours per year are required for maintenance downtime. The company also notes that its microturbines are equipped with an inverter and, as a result, they deliver data-center quality power, which is particularly important with sensitive Internet of Things instrumentation, such as sensors and actuators installed on the field's equipment that collect and exchange data via the internet, which can be disturbed by unclean power. In addition, Capstone Green Energy points out that its products can operate on oil pipeline boil-off gases with appropriate gas pretreatment.

3.8 Mini LNG Solutions

Mini LNG Solutions	**TRL: Mature & Commercial, API 7** *(Production system field proven)*
Overall description: LNG (liquefied natural gas) is natural gas that has been cooled down to liquid form (between -145°C and -163°C) for ease and safety of non-pressurized storage and transport (LNG can be transported by road, rail and sea). Its energy density amounts to about 22 MJ/liter, i.e. 2.5 times higher in comparison to CNG and over 600 times higher relative to natural gas at atmospheric pressure. The liquefaction process is carried out at LNG plants. After delivery to consumers, LNG can be re-gasified, i.e. converted back to natural gas, at special terminals (regasification plants / terminals) or used as LNG as e.g. truck fuel. Three different types of liquefaction processes can be applied in small-scale LNG plants[31]: ▪ Single-mixed refrigerant (SMR) process is the most commonly used. After treatment, the feed gas is totally liquefied. Only a small amount of flash gas is produced, as the LNG is let down to storage. LNG yields of over 98% are typical (excluding the natural gas that is consumed to power the liquefaction process), and because the system uses a mixture of refrigerant components and can be tailored to the specific application, it offers substantial flexibility. As noted by JGC Holdings Corporation, the SMR process tends to offer better efficiency in comparison to N_2 cycle. ▪ N_2 refrigeration process, also known as the N_2-cycle, utilizes N_2 as the working fluid to accomplish liquefaction. The process works by compressing the N_2 in a large compressor and then cooling and expanding it in two steps to produce temperatures low enough to liquefy the feed gas. This process has been used for more than 20 years, but it has had limited application recently because of the large amount of power required to circulate the N_2. ▪ The methane expansion process, also known as the expander process, applies methane itself as a refrigerant: after compression and cooling, the gas is split into parts, the major portion is expanded and used as refrigerant, the minor portion to be liquefied is sent to a carbon dioxide (CO_2)-removal unit and then on to the cold box. In international practice the term "small-scale" or "mini LNG" typically refers to plants with the liquefaction capacity of up to 1 MTPA (about 130 MMSCFD).	*Alabama Gas Co.'s LNG plant in Pinson, Alabama*  *Source: Gas Processing & LNG*  https://www.galileoar.com/us/small-scale-distributed-lng-production/

[31] B. Price, M. Mahaley & W. Shimer (2014) Optimize small-scale LNG production with modular SMR technology. Gas Processing & LNG. Available at: http://www.gasprocessingnews.com/features/201404/optimize-small-scale-lng-production-with-modular-smr-technology.aspx

Where a pipeline may be uneconomic or not yet constructed, small-scale LNG may offer a "virtual pipeline" to transport gas to supply power plants, industrial consumers, and / or for use as a fuel for cars and trucks. **Notable about this technology:** ▪ Construction of a small-scale LNG plant may be a particularly attractive solution in remote regions located far from the centralized gas supply system, where there is demand for natural gas. The economic efficiency of the project will largely depend on the value of LNG compared to alternative fuels in a particular area, in other words the position of LNG in the inter-fuel competition will frequently be the decisive factor. ▪ It should also be noted that in some regions small-scale LNG plants may benefit from the state support measures aimed at the development of the LNG market that had been introduced due to the better environmental impact of liquefied natural gas in comparison to alternative fuels and other reasons. In particular, the Russian government is implementing a program to support the development of the NGV (natural gas vehicles) market32, which subsidizes the conversion of vehicles to NGV fuel, production of NGVs, as well as the creation of infrastructure facilities, including LNG filling stations. **Notable limitations:** While LNG has a higher energy density than CNG, which makes it a more attractive option for transporting larger (>~ 5 MMSCFD) gas volumes and / or distances to market, LNG also demands higher capital cost, which can make it economically unattractive for small gas volumes.[33] Liquefaction facilities require pre-treatment to remove water CO_2 and mercury.[34] Additional pre-treatment may be needed if the feed gas contains sulphur compounds. In most cases LNG must be re-gasified, i.e. converted back to natural gas, after delivery to consumers, which requires the availability of special terminals (known as regasification plants or terminals). This excludes the applications with direct use of LNG, i.e. as a motor fuel for vehicles.	
Capacity range (MMSCFD)	The technology can be implemented at new or mature fields with a wide capacity range. According to Expansion Energy, the minimum feed gas rate is about 0.25 MMSCFD. There is virtually no upper bound, although the term "small-scale" or "mini LNG" typically refers to plants with the liquefaction capacity of up to 1 MTPA (about 130 MMSCFD). Numerous other technology providers offer small-scale LNG solutions with minimal capacity of 0.25-4.0 MMSCFD, these include Beerensgroup DMCC, Chart Industries, Galileo, GE and others.[35]
Type of product produced	The final product is liquefied natural gas (LNG), although it should be noted that some technology providers, in particular Expansion Energy and JGC Holdings Corporation, offer solutions that allow to produce LNG and NGLs within an integrated process.
Amount of yield per MMSCF gas	As part of the liquefaction process some of the feed gas is used to power the equipment. For example, according to Expansion Energy, the VX Cycle developed by the company allows to produce LNG and NGLs with at least 70% of the feed

[32] Decree of the Government of the Russian Federation dated April 15, 2014 N 321 (as amended of March 31, 2021) "On Approval of the State Program of the Russian Federation "Development of the Energy Sector". [In Russian] Available at: http://www.consultant.ru/document/cons_doc_LAW_162194/
[33] GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. Mini-LNG, p. 29. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf
[34] Ibid., p. 29
[35] Ibid., pp. 30-34

	gas becoming saleable product and not more than 30% used to power the cycle. It should be highlighted that the consumption of 30% is the worst-case scenario since the actual performance of the unit in this aspect largely depends on its capacity, as well as the composition of AG. In this regard, the availability of power from the grid can also enhance the efficiency of the conversion of feed gas into LNG. Assuming that 70-90% of feed gas is converted into LNG, 1 MMSCFD can yield from 5.4 to 6.9 kt of LNG per annum.
Pre-treatment requirements	Liquefaction facilities require pre-treatment to remove water CO_2 and mercury.[36]. Additional pre-treatment may be needed if the feed gas contains sulphur compounds. Maximum allowed content of contaminants typically amounts to about 50 ppm of CO_2, 1 ppm of H_2O and 4 ppm of H_2S.[37] It should also be noted that certain technology providers, in particular Expansion Energy and JGC Holdings Corporation, include the pre-treatment facilities in the liquefaction solutions that they provide.
Modularity	Modular and scalable liquefaction units are available, including truck-mounted options. The units can be re-positioned after field life for re-use elsewhere.[38]
Other scalability potential	Some liquefaction technologies have been specifically designed with modularity in mind. Expansion Energy highlights that its VX Cycle design makes it inherently easier to provide pre-engineered, shop-fabricated and modularized or containerized LNG plants, which makes it easier for EPC or fabrication companies to provide turnkey small-scale LNG facilities. JGC Holdings Corporation notes that the company can supply both modular and stick built LNG solutions, scalability potential is also available.
Auxiliary/additional utilities required	Required utilities may include power from grid, although autonomous units are also commonly available.[39] In addition, depending on the type of the liquefaction process, supply of refrigerant may be required, e.g. the nitrogen expansion cycle uses nitrogen as a refrigerant. In this regard, the methane expansion liquefaction cycle has an advantage since it utilizes CH_4 as a refrigerant and, thus, provides greater autonomy for an LNG plant.
Applicability (offshore/ onshore)	Technically, small-scale LNG plants can be implemented both onshore and offshore.[40] However, it should be noted that offshore deployment may be associated with certain difficulties. In particular, Expansion Energy points out that, although the liquefaction facilities themselves are compact enough, opportunities for tank storage are quite limited at platforms. The implementation of offloading system can also be challenging in case of offshore deployment. These issues result in increased costs for the offshore options. In general, according to JGC Holdings Corporation, offshore LNG plants can be economically viable in case of higher capacity (about 1+ MTPA), while the costs associated with offshore deployment are typically too high for the small-scale solutions.
Ambient temperature limitations	LNG plants have been successfully implemented in various climatic conditions, including relatively hot, e.g. in Algeria, and extremely cold, e.g. in the Russian Arctic. It should be noted that since the liquefaction process involves cooling, plants located in cold climates, all else being equal, tend to be more efficient.

[36] GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. Mini-LNG, p. 29. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf
[37] Ibid., pp. 29-34.
[38] Ibid.
[39] Ibid.
[40] Ibid.

Minimum feed pressure required	Minimum feed gas requirements largely depend on the technology provider. Minimal inlet pressure requirements amount to at least 50 psi.[41] However, as noted by JGC Holdings Corporation, the issues associated with low pressure can be resolved through the installation of a boosting compressor. In addition, as noted by Expansion Energy, unstable or variable gas feed does not adversely affect the process.
Temperature operational range	As part of the liquefaction process natural gas is cooled down to between -145°C and -163°C. As noted by Expansion Energy, the required temperature of liquefaction depends upon the pressure at which the process is conducted with lower temperatures needed at lower pressure conditions.
Other climatic constraints	No other limitations related to climatic conditions have been identified.
Other carbon footprint/ environmental impacts	Small-scale LNG plants generate emissions since typically 10-15% of feed gas is combusted for powering the process/production equipment in case of on-site electricity generation. In addition, JGC Holdings Corporation points out that the negative environmental impact can be minimized. In particular, in case of electrification of the driver in the plant and application of renewable energy sources to power the equipment the amount of emissions would be extremely small. Emissions are also generated by heavy duty trucks that are used to deliver LNG to consumers, they amount to about 900 g of CO_2 per km.[42]
Safety concerns	Although LNG takes up 1/600th of the volume of the gaseous state of natural gas, while retaining all of the energy potential, the operations of liquefaction facilities are not associated with substantial safety issues due to the fact that they are constructed in accordance with applicable standards. In particular, Expansion Energy notes that in the US small-scale LNG plants are built in line with the standards of the National Fire Protection Association (NFPA), which are considered to be quite rigorous. JGC Holdings Corporation confirms that there is no specific concern on the safety of operations. The company points out that numerous safety systems are in place, such as gas detectors, pressure safety systems, fire alarms, etc. In addition, given the fact that in case of small-scale LNG plants the product is typically transported by trucks, the general issues of road safety must also be taken into account.
Applicability for CCS/CCUS	CCS technology has already been successfully implemented at a major LNG project – Gorgon LNG in Australia.[43] For small-scale LNG plants, Expansion Energy and JGC Holdings Corporation point out that liquefaction facilities can be integrated with CCS/CCUS solutions. Examples of such laboratory and field-tested technologies that currently await commercial deployment include: ▪ VCCS Cycle, which is based on capturing CO_2 emissions from the emitting plants and permanently sequestering them through “mineralization”[44]; ▪ DDR membrane process that is a high-efficiency CO_2 separation technology using a DDR-type zeolite membrane. It is suitable for CO_2 separation from

[41] Ibid.
[42] Transport & Environment (2015) Too big to ignore – truck CO_2 emissions in 2030, p. 2. Available at https://web.archive.org/web/20210420121934/https://www.transportenvironment.org/sites/te/files/publications/2015%2009%20TE%20Briefing%20Truck%20CO2%20Too%20big%20to%20ignore_FINAL.pdf
[43] Chevron (2019) Gorgon carbon dioxide injection project. Available at: https://australia.chevron.com/-/media/australia/publications/documents/gorgon-co2-injection-project.pdf
[44] Expansion Energy (2016) “VCCS Cycle” for Carbon Capture & Sequestration + Coal Ash Remediation + Minerals Recovery. Expansion Energy official website. Available at: http://www.expansion-energy.com/vccs_for_carbon_capture__sequestration__coal_ash_remediation__minerals_recovery

	associated gas deriving from CO_2-EOR and natural gas with high CO_2 content[45]; ▪ HiPACT process that recovers CO_2 at high pressures from natural gas and synthesis gas.[46]
Other considerations	It should be noted that certain small-scale technologies, in particular Expansion Energy's VX Cycle, allow to produce sub-cooled LNG, which is less susceptible to boil-off in comparison to "conventional" LNG.

3.9 CNG "Virtual Pipelines" & Mobile CNG Filling Stations

CNG "Virtual Pipelines" & Mobile CNG Filling Stations	**TRL: Mature & Commercial, API 7** *(Production system field proven)*
Overall description: CNG (compressed natural gas) is made by compressing natural gas to less than 1% of the volume it occupies at standard atmospheric pressure. Its energy density amounts to about 9 MJ/liter, i.e. almost 250 times higher in comparison to that of natural gas before the compression. CNG is primarily used as a motor fuel for vehicles that have been either converted or specifically manufactured to run on compressed natural gas. The compression typically occurs directly at CNG filling stations that source natural gas from pipelines. In addition, due to the fact that compression of natural gas allows its economic transportation to markets via road transport, CNG also allows to establish a "virtual pipeline" in order to supply small-scale power plants, industrial consumers, households or CNG filling stations that do not have access to conventional pipeline gas. In this case, CNG is stored in special containers that typically consist of stacked pressurized cylindrical gas bottles and delivered to the final consumers by trucks. One truck typically can deliver about 0.25 MMSCF per cargo. Although construction of a stationary CNG filling station directly at the field is not likely to be an economically viable option due to the limited potential for on-site consumption, the compression of natural gas still can be used as a means of AG utilization. Two types of application of CNG will be covered in this report – "virtual pipelines", i.e. construction of compression facilities at the field and delivery of CNG to final consumers by trucks, and mobile CNG filling stations – a compact technology mounted on either a truck or a trailer for mobility that allows to compress natural gas, store CNG and refuel CNG vehicles. One mobile CNG filling station mounted on a truck or a trailer can typically carry about 0.09 MMSCF. Although these two utilization options significantly differ from each other only in terms of the intended "purpose" i.e. delivery of natural gas to large consumers in the case of "virtual pipelines" and refueling CNG vehicles in the case of mobile CNG filling stations, their principles of operation generally coincide, so they will be considered within a single section of this report. **Notable about this technology:** CNG offers lower capital costs relative to LNG, which can make it a particularly attractive option in the case of the opposite scenario – smaller	*CNG-carrying truck for delivery of CNG to consumers ("Virtual pipeline")*  *Source: Galileo Technologies* *L-CNG full skid-mounted refueling device supplied by Houpu Clean Energy*  *Source: Houpu Clean Energy* *KAMAZ Industrial Components mobile compressed CNG filling station*  *Source: KAMAZ Industrial Components*

[45] JGC Holdings Corporation. DDR Membrane - CO_2 Separation for Natural Gas Treatment. Available at: https://www.jgc.com/en/business/tech-innovation/environment/ddr-membrane.html
[46] JGC Holdings Corporation. HiPACT - an Innovative CO_2 Capture Process. Available at: https://www.jgc.com/en/business/tech-innovation/environment/hipact.html

volumes of AG production (<~5 MMSCFD[47]) and / or shorter distances to market. **Notable limitations:** CNG has a considerably lower energy density in comparison to LNG, which makes it a less viable option in case of larger AG production volumes and / or longer distances to market since a substantially greater number of trucks would be required for delivery of the product to consumers. Since for supplying both "virtual pipelines" and mobile CNG filling stations CNG serves as an alternative to pipeline natural gas, it must be treated in order to meet pipeline quality specification.	
Capacity range (MMSCFD)	The technology can be implemented at new or mature fields with a wide capacity range. The basic technical component of CNG is gas compression. **"Virtual pipelines"** The smallest capacity of stationary natural gas compression units is about 0.2 MMSCFD.[48] There is virtually no upper bound due to the scalability of small-scale units and the possibility of deploying multiple trains. However, as noted above, in the case of large volumes of production, LNG may be a more economic option. **Mobile CNG filling stations** In case of mobile CNG filling stations the smallest capacity is similar, e.g. the solutions offered by KAMAZ Industrial Components have a smallest capacity of 300 NCM/h, which translates to about 0.25 MMSCFD, while the largest unit has a capacity of about 2.4 MMSCFD.[49] Due to the possibility to deploy multiple units, there is virtually no upper bound.
Type of product produced	Natural gas that is transported in a compressed form.
Amount of yield per MMSCF gas	If the equipment is powered by a gas reciprocating unit, some of the AG will be consumed to generate electricity, e.g. the 400 hp CNG-400[50] provided by GE requires 400 kW of power and has the capacity to compress up to 1.4 MMSCFD.[51] Assuming the AG consumption of a gas reciprocating unit of 0.34 MMSCFD per 1 MW[52], the CNG-400 will consume about 0.14 MMSCFD. Thus, out of 1 MMSCFD of feed gas approximately 0.9 MMSCFD will be compressed. In case the equipment is powered from the grid, the losses are virtually non-existent.
Pre-treatment requirements	As noted by Houpu Clean Energy, pre-treatment requirements depend upon the composition of feed gas. Since CNG filling stations are typically fed from pipelines, they require pipeline-spec quality gas. In particular, water and sulphur must be removed prior to compression. Typically the maximum allowed volume of contaminants in the US is 0.05% H_2S and 3% of CO_2.[53] H_2O removal is particularly important in the case of

[47] GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. CNG – Compressed Natural Gas, p. 27. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf
[48] GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. CNG – Compressed Natural Gas, p. 28. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf
[49] KAMAZ Industrial Components. Mobile CNG filling station. Technical Characteristics. KAMAZ Industrial Components official website. [in Russian] Available at: https://industrial-kamaz.ru/products/agnks/AGNKS.jpg
[50] GE. CNG in A Box system. The cheaper, faster, convenient fuel solution for natural gas vehicles, p. 7. Available at: https://pdf.directindustry.com/pdf/ge-compressors/cng-box-system/115061-389671.html
[51] GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. CNG – Compressed Natural Gas, p. 28. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf
[52] GGFR (2018) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. Power generation, p. 15
[53] M.M. Foss (2004) Interstate Natural Gas – Quality Specifications & Interchangeability. Center for Energy Economics, p. 15. Available at: https://www.beg.utexas.edu/files/energyecon/global-gas-and-lng/CEE_Interstate_Natural_Gas_Quality_Specifications_and_Interchangeability.pdf

	CNG since water content may cause freezing of the equipment (as water freezing temperature increases under pressure).[54] Houpu Clean Energy points out that certain treatment facilities, in particular the dehydrator, are typically integrated into the equipment. It should also be noted that in case of mobile CNG filling stations pre-treatment facilities may also be included in the standard offering of technology providers. In particular, as noted by KAMAZ Industrial Components, gas passes through cleaning and drying systems at the mobile CNG filling station.[55]
Modularity	**"Virtual pipelines"**
Other scalability potential	Modular and scalable solutions are available. The units can be re-positioned after field life for re-use elsewhere. In particular, GE offers the CNG in A Box modular solution with the maximum unit size of 2.6 MMSCFD and the scalability potential of up to 20 units.[56] As noted by Houpu Clean Energy, the technology can be provided as a containerized solution. **Mobile CNG filling stations** Mobile CNG filling stations are offered as standardized truck or trailer-mounted solutions. Scalability potential is significant since multiple units can be deployed.
Auxiliary/additional utilities required	According to Houpu Clean Energy, CNG facilities typically require access to power grid, however on-site power generation is also possible.
Applicability (offshore/ onshore)	"Virtual pipelines" and mobile CNG filling stations are both, by design, onshore applications since the former assumes trucks delivering the CNG to consumers are loaded directly at the CNG facility at the oilfield, while the latter are either truck- or trailer-mounted solutions.
Ambient temperature limitations	**"Virtual pipelines"** According to Houpu Clean Energy, CNG facilities can be used in practically any environmental conditions, and the ambient temperature range may vary from -45-55°C to +55°C. However, the company indicated that some components, such as displays, must be changed in order to ensure efficient operation in extremely cold climates. It should also be noted that, like most gaseous molecules, CNG volume expands in higher temperature conditions and contracts in colder environments, e.g. a CNG vehicle tank that can hold 45 GGE (gasoline gallon equivalent) at 3600 psi at 21°C may only hold 75% (or less) of that volume on a 35°C day.[57] In this regard, colder climates can be beneficial for CNG "virtual pipeline" projects due to better CNG transport efficiency. **Mobile CNG filling stations** No significant limitations related to ambient temperature conditions apply to mobile CNG filling stations. In particular, according to KAMAZ Industrial Components, operating ambient temperature can range from -50°C to +40°C.[58] The issue of changing density and volume of CNG under various temperature conditions, and its effect on the efficiency of storage, is also applicable in case of mobile CNG filling stations.

[54] Compac (2014) CNG Dispenser Service Manual, Russia. Document version 1.0.2. Compac official website. Available at: https://www.compac.biz/vdb/document/100

[55] KAMAZ Industrial Components (2021) Products. Mobile CNG filling station. KAMAZ Industrial Components official website. [in Russian] Available at: https://industrial-kamaz.ru/products/agnks/

[56] GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. CNG – Compressed Natural Gas, p. 28. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf

[57] Midwest Energy Solutions (2021) Temperature & Pressure. Midwest Energy Solutions official website. Available at: https://www.midwestenergysolutions.net/cng-resources/temperature-pressure#:~:text=Like%20most%20gaseous%20molecules%2C%20CNG,on%20a%2095%20degree%20day.

[58] KAMAZ Industrial Components (2021) Products. Mobile compressed gas filling stations. Technical specifications. KAMAZ Industrial Components official website. [In Russian] Available at: https://industrial-kamaz.ru/products/agnks/AGNKS.jpg

Minimum feed pressure required	**"Virtual pipelines"** Galileo Technologies, who offer CNG "virtual pipeline" solutions, indicates that minimum required inlet pressure is as low as 2 psi.[59] According to Houpu Clean Energy, at larger CNG facilities with capacity of about 4.2 MMSCFD the typical inlet pressure amounts to about 60-150 psi.. **Mobile CNG filling stations** CNG Center indicates that optimal inlet pressure amounts to 70-170 psi, however the equipment can operate with both higher and lower pressure gas.[60] In case of the solutions provided by KAMAZ Industrial Components, the equipment is designed for the inlet pressure of about 290-1000 psi, while the vehicles are refueled at a pressure of about 2750 psi.[61]
Temperature operational range	According to Houpu Clean Energy, the outlet temperature of compressed natural gas typically amounts to +45°C, although in some cases it may be higher – up to about +65°C. Other sources indicate the outlet gas temperature range of +10-40°C.[62]
Other climatic constraints	No other climatic constrains have been identified.
Other carbon footprint/ environmental impacts	Small-scale CNG facilities produce some emissions due to combustion of about 10% of feed gas for powering the process/production equipment in case of on-site electricity generation. Emissions are also generated by heavy duty trucks that are used to deliver CNG to consumers, they amount to about 900 g of CO_2 per km.[63] Houpu Clean Energy also points out that since hydraulic compressors use oil for lubrication certain risks of spill thereof also exist. In addition, compressors tend to cause noise pollution.
Safety concerns	Although the energy potential of a specific volume of CNG is significantly greater in comparison to natural gas in its gaseous state, the operations of compression facilities are not associated with substantial safety issues due to the fact that they are constructed and operated in accordance with applicable standards. In particular, in the US CNG filling facilities, including mobile ones are governed by numerous Safety and Code Requirements.[64] In addition, the technology providers point out that the technology is mature, which further reduces any operational safety risks. In addition, given the fact that CNG is typically delivered to consumers by trucks, the general principles of road safety must also be taken into account.
Applicability for CCS/CCUS	The emissions of mobile CNG stations are limited due to their small scale, the application of CCS/CCUS technologies is unreasonable.
Other considerations	Houpu Clean Energy additionally points out that the composition of feed gas is important for the efficient operation of compressors, which are the critical component of CNG facilities.

[59] Galileo Technologies (2021) CNG/Bio-CNG Compression. Microbox. Main features. Galileo Technologies Official websitr. Available at: https://www.galileoar.com/en/cng-compressors-and-dispensers-2/microbox-cng-compressor/
[60] CNG Center. Mobile CNG Fueling equipment. CNG Center official website. Available at: https://cngcenter.com/cng-equipment/mobile-cng-fueling-station/
[61] KAMAZ Industrial Components (2021) Products. Mobile compressed gas filling stations. KAMAZ Industrial Components official website. Available at: https://industrial-kamaz.ru/en/products/agnks/
[62] Global Gas Energy (2018) CNG PRMS. Decompression and metering booths. Available at: https://globalgasenergy.com/wp-content/uploads/2018/07/01_GGE_catalogoweb_CNG_PRMS-EN.pdf
[63] Transport & Environment (2015) Too big to ignore – truck CO_2 emissions in 2030, p. 2. Available at https://web.archive.org/web/20210420121934/https://www.transportenvironment.org/sites/te/files/publications/2015%2009%20TE%20Briefing%20Truck%20CO2%20Too%20big%20to%20ignore_FINAL.pdf
[64] Drive Natural Gas Initiative. CNG Infrastructure Guide for Prospective CNG Developer. Available at: https://www.aga.org/sites/default/files/sites/default/files/media/cng_infrastructure_guide.pdf

3.10 Small-scale GTC

Small-scale GTC	TRL: Commercial API 6 (Production system installed & tested) to API 7 - (Production system field proven)
Overall description: Natural gas can be used as a feedstock for the production of chemical products – ammonia (NH_3) or methanol (CH_3OH) – in small-scale gas-to-chemical (GTC) plants. The first step in the process is the same for both ammonia and methanol and involves the generation of hydrogen via one of the three processes: steam methane reforming, which is the most commonly used option, dry reforming of methane or partial oxidation of methane.[65] Steam methane reforming (SMR) is a reaction, in which methane is heated with steam, usually with a catalyst, in order to obtain a mixture of carbon monoxide and hydrogen, which is also known as syngas or synthesis gas.[66] Dry methane reforming refers to the catalytic reforming of CH_4 with carbon dioxide to produce syngas[67], while partial oxidation is a technically mature process in which natural gas is mixed with a limited amount of oxygen in an exothermic process.[68] In order to produce ammonia the hydrogen is then catalytically reacted with nitrogen: $3H_2 + N_2 \rightarrow 2NH_3$. The nitrogen required for the process is separated from the atmospheric air at an air separation unit (ASU). It should be noted that this process tends to be quite energy-intensive.[69] In the case of methanol production, the hydrogen reacts with carbon monoxide, also over a catalyst (the most widely used catalyst today is a mixture of copper and zinc oxides, supported on alumina): $CO + 2H_2 \rightarrow CH_3OH$. **Notable about this technology:** Production of chemicals may be an economically attractive technology for AG utilization in case of availability of a local market for ammonia or methanol, particularly if other solutions are unavailable due to remoteness of gas transmission infrastructure. It should be noted that methanol is a significantly more attractive option in this respect as it can be consumed on-site since it is widely used as a hydrate inhibitor in the oil and gas industry. Thus, given the high costs of transporting methanol purchased from external manufacturers to the field, the creation of its own production facility can provide significant savings for an oil and gas company. Ammonia, on the other hand, is used mainly in the production of nitrogen fertilizers, primarily urea, and, given the relatively high cost of transportation of the product, finding a consumer of ammonia produced from AG can be challenging.	*CompactGTL's 20 bpd GTL plant at a Petrobras research facility in Aracaju, Brazil.*  *Source: Hydrocarbon Engineering*

[65] De Campos Roseno, K.T. et al. (2018) Syngas production using natural gas from the environmental point of view. Biofuels-State of Development, pp. 273-290. Available at: https://www.intechopen.com/chapters/59618
[66] Steam-Methane Reforming Reaction: $CH_4 + H_2O$ +heat $\rightarrow CO+3H_2$.
[67] Arora S. and Prasad R. (2016) An overview on dry reforming of methane: strategies to reduce carbonaceous deactivation of catalysts. RCS Advances. Issue 110. Available at: https://pubs.rsc.org/en/content/articlelanding/2016/ra/c6ra20450c
[68] De Campos Roseno, K.T. et al. (2018) Syngas production using natural gas from the environmental point of view. Biofuels-State of Development, pp. 273-290. Available at: https://www.intechopen.com/chapters/59618
[69] J. Jianga et al. (2018) Energy Consumption Optimization of a Synthetic Ammonia Process Based on Oxygen Purity. Chemical Engineering Transactions. Vol. 70, 2018. Available at: https://www.aidic.it/cet/18/70/081.pdf

In this regard, production of methanol is a much more common option for monetization of AG through small-scale GTC plants and, for this reason, the focus in this section of the report will be placed on it.

In addition, it should be noted that GTC solutions allow high content of CO_2 in feed gas. In particular, at least 20 mole % of carbon dioxide is acceptable in case of methanol production.[70]

Notable limitations:

Water supply is required since H_2O is used during the steam methane reforming process.

Feed gas treatment may be required. If necessary, the first step is desulphurization, which is typically conducted through amine treatment, and removal of N_2. The second step is typically the pre-reforming process, which involves partial decomposition of any heavier hydrocarbon components of the feed gas and their hydrogenation.

In addition, small-scale GTC plants typically require access to the electricity grid due to substantial power consumption (comparable to that of small-scale LNG and mini GTL plants), although gas-driven options are also available.

GTC technologies are generally capital intensive (like other GTL/GTC technologies).

Capacity range (MMSCFD)	According to technology providers, pilot methanol plants may have the capacity as low as 0.5-1.5 metric t per day, which translates to about 0.02 – 0.07 MMSCFD. The maximum capacity is not restricted, although typical small-scale methanol plants are capable of producing up to 60-80k metric tonnes per annum (5.2 – 10.0 MMSCFD depending on the efficiency and capacity of the plant). According to Safe Technologies Industrial Group, the minimal economically viable capacity amounts to at least 8-10k metric t per annum (0.7 – 1.3 MMSCFD). It should be noted that the plants of such a small scale may be effective only if the conditions for the implementation of the project are highly favorable, e.g. if the plant is deployed at a remote field that requires methanol for own consumption (in this case the value of methanol would be very significant since the only alternative for the operator would be to purchase methanol from third-parties with substantial transport costs).
Type of product produced	Ammonia or methanol depending on the type of a GTC plant. Safe Technologies Industrial Group notes that methanol produced at small-scale plants may range in terms of its grade and quality from crude methanol (93%+ purity) to commercial methanol (grade A/AA – 99.9% methanol content), although the latter is rarely produced since technical methanol (up to 99%) has sufficient quality for consumption on-site and more sophisticated and, consequently, more expensive equipment is required to obtain grade A/AA product.
Amount of yield per MMSCF gas	**Ammonia** Production of 1 t of ammonia requires 1115-1250 SCM (0.04 MMSCF) of natural gas.[71] Consequently, 1 MMSCFD of AG yields about 8.2-9.2 kt of ammonia per annum. **Methanol** Production of 1 t of methanol requires 900-1300 SCM (0.03 – 0.05 MMSCF) of natural gas with about 100 SCM (0.004 MMSCF) used for own consumption of the unit. As noted by Safe Technologies Industrial Group, the latter figure is relatively small as heat is generated in the process of the products' oxidation. As a result, 1 MMSCFD of AG can produce about 8-11.5 kt of methanol per annum.

[70] Al-Adwani H.A. (1992) A kinetic study of methanol synthesis in a slurry reactor using a $CuO/ZnO/Al_2O_3$ catalyst, p. 73. Available at: https://www.osti.gov/servlets/purl/7046137

[71] Newchemistry.ru (2006) Base chemistry and petrochemistry. [in Russian] Available at: https://newchemistry.ru/letter.php?n_id=682

Pre-treatment requirements	Feed gas treatment is required. If necessary, the first step is desulphurization, which is typically conducted through amine treatment, and removal of CO_2 and N_2. The second step is typically the pre-reforming process, which implies partial decomposition of heavier components of the feed gas and their hydrogenation. For this purpose, either steam or hydrogen-containing gas from the tail of the process (or both) can be fed into the pre-reformer. Safe Technologies Industrial Group highlights that the need for pre-reforming is primarily determined by the composition of the feed gas. If it contains a small amount of heavy components, pre-reforming is not required, however with a large content of heavy components the opposite is true. As a rule, pre-reforming is needed for AG processing and is not required in the case of natural gas. However, if the natural gas contains significant amounts of, for example, ethane it will require pre-reforming prior to steam reforming. Small-scale methanol plants can typically tolerate up to 0.4% of H_2S. In addition, it should be noted that GTC solutions allow high content of CO_2 in feed gas. In particular, at least 20 mole % of carbon dioxide is acceptable in case of methanol production.[72]
Modularity	Modular GTC solutions are available. The units can be re-positioned after field life for re-use elsewhere.
Other scalability potential	According to Safe Technologies Industrial Group and LLC "New Technologies", modular containerized methanol plants are economically viable for capacity of up to 40-50 k t of methanol per annum, while units capable of higher output are usually more efficient in a conventional, non-modular, configuration. Typically, in the case of containerized small-scale methanol plants, the set of equipment will consist of 20-40 modules (depending upon the capacity of the plant), each with the size of a standard 40-foot container. The individual elements of higher capacity methanol plants (~40-50+ kt of methanol per annum) tend to be larger, which makes the implementation of modular solutions challenging.
Auxiliary/additional utilities required	Small-scale methanol plants typically require access to the power grid, although gas-driven options are also available. In addition, a water source is required (natural water sources are acceptable). According to Safe Technologies Industrial Group, creation of a fully autonomous unit is possible, although it typically does not make economic sense due to substantial power consumption. In addition, LLC "New Technologies" notes that the availability of transport infrastructure, as well as access to the electricity grid makes construction cheaper and faster.
Applicability (offshore/ onshore)	Certain technology providers, in particular Bluescape Clean Fuels[73], and feasibility studies[74] indicate that small-scale methanol plants can technically be deployed offshore. However, it should be noted that at the time of writing this report no cases of implementation of such projects have been identified in the global practice. LLC "New Technologies" also notes that in the case of implementation of a small-scale methanol plant for AG utilization offshore, spatial limitation on the platform must be considered. In addition, a desalination plant may likely be required in order to provide the water supply.
Ambient temperature limitations	No particular ambient temperature limitations exist, although it should be noted that in warm climates the efficiency of methanol production units tends to decrease.

[72] Al-Adwani H.A. (1992) A kinetic study of methanol synthesis in a slurry reactor using a $CuO/ZnO/Al_2O_3$ catalyst, p. 73. Available at: https://www.osti.gov/servlets/purl/7046137

[73] GGFR (2021) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. Mini-GTL, p. 40. Available at: https://documents1.worldbank.org/curated/en/469561534950044964/pdf/GGFR-Technology-Overview-Utilization-of-Small-Scale-Associated-Gas.pdf

[74] Kato, K. et al. (1997) Floating Methanol Production System (FMPS) for Small Scale Gas Fields. Available at: https://www.jstage.jst.go.jp/article/jime1966/32/11/32_11_851/_article

Minimum feed pressure required	According to Safe Technologies Industrial Group, the optimal pressure in case of small-scale methanol units is about 45 bar. In case of lower pressure, installation of a booster compressor may be required. The stability of AG feed is also important for efficient operations of the unit, although this issue can often be solved by the installation of a booster compressor. In addition, LLC "New Technologies" notes that there are no restrictions in terms of the maximum pressure and that the variability of pressure is an unfavorable, but not a critical, factor since standby compressors are typically available. Repeated sudden shutdowns, however, may negatively affect the lifetime of the equipment.
Temperature operational range	Methanol production process includes heating to substantial temperatures, up to +850-900°C. The synthesis of methanol itself occurs at about +250-300°C, while pre-reforming is conducted at +400-550°C. Minimal temperature of the methanol production process depends on the oxygen production technology (in case partial oxidation process is applied for syngas production)[75] and NGL removal temperature (-20 to -40°C).
Other climatic constraints	None identified.
Other carbon footprint/ environmental impacts	The first step in the production process of ammonia and methanol is steam methane reforming, which is a chemical reaction that results in the emission of carbon dioxide. In addition, carbon emissions are related to the generation of power that is required to run the plant. Emissions of other greenhouse gases, such as methane, are limited. LLC "New Technologies" also notes that at low concentration methanol is non-toxic and rapidly decomposes in water and soil should methanol leaks occur.
Safety concerns	Since the process of methanol production involves extremely high temperatures (up to 900°C) and involves the risk of hydrogen leaks, it is considered explosion-hazardous. As a result, the operations of the equipment must be monitored closely.
Applicability for CCS/CCUS	LLC "New Technologies" notes that CCS/CCUS solutions can be applied to GTC plants, particularly in the case of implementation of a methanol plant at an oil field. Injection of flue gas CO_2 into oil-bearing reservoirs is an effective method of enhancing oil recovery and production of hard-to-recover oil reserves.
Other considerations	LLC "New Technologies" notes that other challenges associated with the implementation of small-scale methanol plants for AG utilization include the lack of modular equipment of full factory readiness, as well as the location of fields and associated logistical constraints in terms of both delivery of equipment and evacuation of final products. It should also be noted that operation of a small-scale methanol plant requires dedicated operators competent in the field of natural gas chemicals production on-site, which may not be available at the oil and gas company implementing the project.

3.11 Data Centers

Data Centers	**TRL: Commercial,** **API 6** *(Production system installed & tested)* **to API 7 -** *(Production system field proven)*

[75] Methanol plants that apply partial oxidation process for syngas production include air separation units that compress and cool down air to the temperature of about -185°C. The air is then liquefied and separated to oxygen and nitrogen. The oxygen in gaseous phase is compressed and sent to a partial oxidation unit as a raw material for the production of synthesis gas, that is later used for methanol synthesis.
Source: MSK (2014) Production. MSK official website. Available at: http://www.msk.co.rs/en-GB/content/cid253/production

Overall description:	*Data Center provided by Crusoe Energy Systems*
As noted above, installation of gas reciprocating units or gas turbines to produce electricity is one of the commonly used AG utilization technologies. However, the volume of the potential market for generated power may be limited in the absence of access to the electricity grid and low on-site consumption. In such cases, a possible solution for monetizing the generated electricity is the creation of an energy-intensive facility directly at the field. Data centers are one example of such facilities. A data center is a facility that houses a multitude of powerful computers and systems necessary for their operation to process large amounts of data efficiently and without interruption. Organizations use data centers to host their critical data and solve tasks that require significant computing power, such as graphic rendering or training of artificial intelligence models. Such facilities with proper equipment can also be used for cryptocurrency mining. Due to the features and amount of hardware typically placed in data centers, they tend to be very energy-intensive. **Notable about this technology:** In most regions, examples of implementation of this solution are limited to pilot projects. Today they are most widely used in the US, where modular data centers are supplied by Crusoe Energy Systems. The company currently operates 40 modular facilities powered by electricity generated from AG in North Dakota, Montana, Wyoming and Colorado. The company expects this number to increase to 100 units by 2022 as it expands into new markets such as Texas and New Mexico.[76] This solution has significant potential for wider implementation due to the growing interest in the services of data centers amid widespread digitalization: in a number of regions, in particular in Russia, there is already a shortage of “supercomputers” capable of solving tasks that require significant computing power. In this connection, a network of smaller decentralized data centers can be in high demand. In addition, interest in cryptocurrency mining is also on the rise. As noted by Gazprom Neft, a Russian oil & gas company that has deployed pilot data centers at its fields, the solution has a relatively short payback period of 3-5 years. However, the company also points out that due to the rapid development of computing hardware another notable feature of data centers is the rapid obsolescence of equipment. It is also important to mention the high volatility of prices for some types of computing equipment, particularly ASIC-miners, that directly correlate with the value of cryptocurrencies (as with higher prices of cryptocurrencies more individuals and companies seek to purchase the hardware required for mining, thus creating a deficit and pushing the equipment prices up). **Notable limitations:** With that said, in the case of monetization through cryptocurrency mining, short-term interruptions in the operation of computing equipment may cause only a loss of revenue, while in the scenario of provision of the data center services, they may also trigger sanctions for non-fulfillment of obligations to clients. Since modular data centers in the context of AG utilization are an “add-on” to power-generating equipment, the limitations/requirements applicable to gas reciprocating units or gas turbines are also relevant. Where cryptocurrency mining is considered, the applicable local legislation (particularly in the field of taxation) and regulation should be assessed in advance.	 *Source: Crusoe Energy Systems*

[76] Crusoe Energy Systems (2021) Crusoe Energy is tackling energy use for cryptocurrencies and data centers and greenhouse gas emissions. April 26, 2021. Crusoe Energy Systems official website. Available at: https://www.crusoeenergy.com/blog/69bV5OWklv0xLHcWTDkMVl/crusoe-energy-is-tackling-energy-use-for-cryptocurrencies-and-data-centers-and-greenhouse-gas-emissions

Capacity range (MMSCFD)	There are virtually no restrictions on the capacity range and scalability potential. They are determined by the availability of the energy resources (AG and electricity). When implementing its pilot projects, Gazprom Neft used modular solutions – data centers in 40-foot containers with a capacity of 1 MW each. Scaling up to a total capacity of 25-30 MW would require about 4.8 MMSCFD. The standard solution offered by Crusoe Energy Systems is a modular data center equipped with its own generation capacity of 2 MW, which allows for the utilization of about 0.3 MMSCFD of AG. However, the company has deployed turbine solutions with a capacity of 18 MW (more than 2.7 MMSCFD) and can offer even larger capacity solutions to meet nearly any volume of AG.
Type of product produced	There are two possible directions of data center monetization: 1. Provision of data center services for external clients, i.e. using the capacity of data centers to solve tasks that require significant computing power. 2. Cryptocurrency mining (given the absence of regulatory restrictions). Crusoe Energy Systems notes that computing equipment is not always universally suitable for every computing task. For example, in order to mine cryptocurrencies, it may need to be equipped with ASIC-miners. More versatile equipment that can be used for both mining and provision of data centers services (such as graphical processing units) is also available.
Amount of yield per MMSCF gas	In the case of monetization of data center through the provision of services to external clients, revenue is determined on an individual basis. Due to the insufficient level of development of this market in most regions, it is challenging to provide a proper indicative contract amount. According to our estimates, assuming the AG consumption of a gas reciprocating unit of 0.34 MMSCFD per 1 MW of power[77] and the energy efficiency of a data center of 300 W per 7-130 TFLOPS[78], 1 MMSCFD of AG enables the computing performance of a data center of 69-1273 PFLOPS. As for the monetization through cryptocurrency mining, we estimate that, given the consumption of 151 MWh per bitcoin[79] and the aforementioned efficiency of generating equipment, production of 1 MMSCFD of AG yields about 170.6 BTC[80] ($ 1.2 million[81]). It should be emphasized that the provided values are only our approximate estimates made on the basis of open data sources. Since the computing equipment can vary significantly in terms of performance, as well as due to the extremely high volatility of cryptocurrency rates, actual values can differ significantly.
Pre-treatment requirements	AG preparation requirements are determined by the characteristics of the generating equipment, as well as the composition of the produced AG. Crusoe Energy Systems, which supplies data centers equipped with their own generating capacity, notes that their generators accept a wide range of BTU content including rich gas with entrained liquids. Additionally, desulfurization may be required in case of high H_2S content.
Modularity	The technology is modular and scalable. Data centers can be supplied in standard 40-foot containers.
Other scalability potential	

[77] GGFR (2018) GGFR Technology Overview – Utilization of Small-Scale Associated Gas. Power Generation, p. 15
[78] NVIDIA (2021) NVIDIA Tesla V100 specs. NVIDIA official website. Available at: https://www.nvidia.com/ru-ru/data-center/tesla-v100/
[79] BitOoda (2021) The Weekly Hash, 4/26/2021: Volatile Price Action, Tx Fees Normalize. April 26, 2021. Available at: https://bitooda.medium.com/the-weekly-hash-4-26-2021-volatile-price-action-tx-fees-normalize-4fb2b0ae9dcf
Assumptions: target hash rate – 165 EH/s, ASIC-miner – Antminer S19.
[80] Note: given the efficiency of a gas reciprocating unit of 0.34 MMSCFD per 1 MW, production of 1 MMSCFD provides the generation of 2.94 MW of electricity (25.8 GWh), which, given the consumption of 151 MWh per bitcoin, enables mining of 170.6 BTC per year.
[81] Given the 2020 average BTC exchange rate – 7 188 USD/BTC.

Auxiliary/additional utilities required	In addition to the availability of generating equipment at the field to power the data center, an Internet connection is also required. For small capacities, a GSM modem is sufficient. For larger capacities, a fiber-optic connection may be necessary. In the case of implementation of powerful data centers, the remoteness from the existing infrastructure must be taken into account (the cost of laying 1 km of fiber-optic cable is about 27-40 thousand USD). Crusoe Energy Systems notes that the solutions it offers are focused on maximum autonomy and are capable of operating on a satellite internet connection. The company leverages microwave and millimeter wave networking connections as available. Therefore, even when processing large amounts of data, the presence of a fiber-optic connection is optional.
Applicability (offshore/ onshore)	Existing AG-powered data centers have been implemented onshore, however there are no substantial restrictions on their placement on offshore platforms given the availability of space and power generation facilities. This statement is confirmed by Crusoe Energy Systems who note that in offshore operations the availability of free space is the key limitation.
Ambient temperature limitations	There are no limitations related to ambient temperatures. For the implementation of data centers in cold climates winterized containers can be used. At the same time, placement in a cold climate, other things being equal, is more favorable due to lower costs for cooling. Crusoe Energy Systems also reports that it is in the process of implementing a pilot project in Texas to test its solution in a hot climate.
Minimum feed pressure required	There are minimal restrictions associated with generating equipment. Crusoe Energy Systems, which supplies data centers equipped with their own power generating equipment, notes that inlet pressures at operating projects is typically from 30 to 150 psi and that the optimum pressure range is from 60 to 75 psi. According to Crusoe Energy Systems, the instability of AG feed is an unfavorable, but not critical factor since the equipment has the ability to automatically reduce the load level in the event of a reduction in AG supply.
Temperature operational range	There are no significant restrictions related to the operating temperature range. Installation of an air cooled system is sufficient in order to maintain the optimum temperature.
Other climatic constraints	No other climatic restrictions have been identified.
Other carbon footprint/ environmental impacts	Power generating equipment emits a certain amount of GHGs and pollutants. Crusoe Energy Systems, which supplies data centers equipped with their own power generating equipment, notes that it minimizes emissions from the generating equipment by installing advanced catalytic converters and emission control kits. Crusoe Energy Systems estimates that, by reducing/eliminating gas flaring, up to a 63% reduction in CO_2-equivalent GHG emissions can be achieved.
Safety concerns	There are no significant risks associated with occupational safety.
Applicability for CCS/CCUS	Carbon capture technologies are applicable to the generation equipment that powers the data centers.
Other considerations	The business model applied by Crusoe Energy Systems is based agreement with field operators on the transfer of ownership of the AG. The company then monetizes it through provision of data center services or cryptocurrency mining, while bearing the costs of suppling and operating the equipment. The proposed solution may therefore be particularly attractive for fields where there are no alternative AG utilization options since the operator bears virtually no additional costs.

3.12 Adsorbed NG Storage and Transport

Adsorbed NG Storage and Transport	**TRL:** At industrial scale: Under development - TRL 2 (Proof-of-Concept), For light commercial vehicles: Commercial - TRL 7 - Field Qualified (Field Proven)
Overall Description: Adsorbed natural gas (ANG) technology makes use of a microporous solid (adsorbent) packed into a storage vessel. This enables 1.5 to 3 times the amount of gas to be stored in the same container volume, as compared to CNG. This helps reduce the cost and weight of gas storage containers and/or reduce compression costs. However, 15% to 30% of the gas could get retained by the material after the first emptying of the container, reducing the effective capacity for subsequent filling. Despite that not many industrial applications of ANG for large scale gas transportation are available, ANG containers can theoretically deliver the gas at the required pressure of the receiving discharge point. The natural gas storage capacity of an adsorbent is usually evaluated in terms of its volumetric methane storage capacity (Vm/Vs), where Vm is the volume of stored methane at standard temperature and pressure, and Vs is the volume of the storage container; the Vm/Vs can be from 50 to more than 200. Commercial development of ANG requires adsorbents with low costs and high gas storage capacities. Activated carbon has the most favorable gas storage density to date[82]. Natural Gas adsorption on activated carbon is determined by physisorption. Maximum amount of stored natural gas in a 10-liter tank is equal to 0.78 kg and it gives possibility for recovering 0.75 kg of gas if the tank is warm[83]. The technology is not in widespread use and is only available at a scale suitable for use in light commercial vehicles. Larger scale vessels, e.g., for usage for natural gas storage from upstream facilities, are still at the R&D stage. A research article from 2017 developed a mathematical model for a “large scale” tank that could store 54 kg of natural gas, but this is still an order of magnitude less than what would be required for industrial applications. The charging/ discharging time is estimated to be 4 to 5 minutes at a circulation rate of 10 kg/s. The ANG operating pressure is 500 psi and above. **Notable about this technology:** • Reduction in weight and cost of gas storage tanks, and thus reducing the cost. • Reduction in compression costs as lower pressure is required to store the same amount of gas in the container. **Notable limitations:** • This technology has not been demonstrated for industrial scale storage tanks, only for tanks suitable for fueling light commercial vehicles. • The storage tanks need to be filled with an adsorbent material such as carbon in such a manner as to provide a rigid framework and large surface area.	 *Figure: Adsorbed Natural Gas (ANG) tanks installed in a light commercial vehicle. Source: Ingevity.*

[82] Arora, A., & Bachle, A. (2015). Storage of Natural Gas by Adsorption Process. October, 20–22.
[83] Dziewiecki, M. (2018). Adsorbed Natural Gas Tank feeded with Liquid Natural Gas. E3S Web of Conferences, 44, 1–8. https://doi.org/10.1051/e3sconf/20184400038.

• The rate at which gas can be extracted from a storage tank is lower than CNG unloading and is limited by the rate at which the activated carbon can desorb the gas molecules. • Gas needs to be of pipeline quality, no significant H_2S, CO_2 or water content in the gas is recommended to avoid reducing the life of the adsorbent material.	
Capacity range (MMSCFD)	0.001 MMSCFD (100s to 1000s SCFD for light vehicle operations) For natural gas storage applications, manufacturer Ingevity is targeting 0.2-0.3 MSCF containers.
Type of product produced	Natural gas
Amount of yield per MMSCF gas	75% to 90% of the gas originally stored in ANG containers
Pre-treatment requirements	High purity methane storage only, therefore, NGL and water removal are required. If necessary, desulphurization, CO_2 removal is also required
Modularity	Flexible number of tanks per vehicle
Other scalability potential	Potential for larger scale facilities is unclear at present due to a lack of information. It appears that activity on the development of this technology may have stalled amongst researchers and industry.
Auxiliary/additional utilities required	Electricity for gas compression Filling station for light vehicles During filling, the gas may get overheated and while desorbing the gas can get too cold. Therefore heating / cooling utilities may be required (under research).
Applicability (offshore/ onshore)	Onshore only at present
Ambient temperature limitations	Cold temperatures appear to affect the efficiency of methane extraction from the tanks.
Minimum feed pressure required	At least 500 psi. ANG trucks typically operate on 900 PSI.
Temperature operational range	N/A
Other climatic constraints	Insufficient data
Other carbon footprint/ environmental impacts	Lower emissions that gasoline and diesel when natural gas used as light vehicle fuel, but this can also be achieved with CNG technology.
Safety Concerns	Specific issue to consider is to make sure carbon fragments do not get to the gas system (filters should be used to prevent the carbon dust entering the gas pipeline).
Applicability for CCS/CCUS	-
Other considerations	None

3.13 Ejectors for flare gas recovery

Ejectors for flare gas recovery	TRL: Mature and commercial API 7 Field Qualified *(Field Proven)*

Overall Description:
Ejectors are not a gas utilization technology per se, but rather a technology to facilitate regulating gas pressure to a desirable level without use of compression to bring low-pressure gas to a utilization point. Ejectors can be used to replace compressors that are typically more expensive to install and operate, and often require specialist maintenance and expensive spare parts.

Ejectors make use of a high-pressure motive fluid to compress low pressure gas that would otherwise be flared or vented. The increased pressure of the gas stream enables its input to e.g., a fuel gas stream or other Flare Gas Recovery (FGR) system. The pressure of the motive fluid should typically be 2-10 times larger than the required discharge pressure, dependent on gas's properties, and required output pressure.

Ejectors employed on FGR applications can be categorized in two groups, depending on the motive fluid which is used to drive them: gas ejectors and liquid ejectors. Examples of potential motive fluids are high-pressure gas routed from a production separator, fuel gas, nitrogen or a small side-stream from a gas lift or gas injection compressor discharge. A motive water stream could come from a side-stream from an existing water pump or a dedicated water pump.

If water is used as the motive fluid, it is necessary to separate it from the recovered gas. Some locations such as Gas Oil Separation Plants have large 3-phase separators on site already. If the capacity is large enough in these separators, it may be possible to route the discharge line from the ejector to this separator, eliminating the need for a dedicated separator for the FGR[84].

Main components:

- Seal or valve that directs normal flow of 'flare' gas to the ejector, but enables large, unsafe surges of gas to be flared
- One or more ejectors acting in parallel (modular design)
- Control System to manage the variable flare gas rate entering the system and manage the suction pressure accordingly
- Gas-water separator (if water used as motive fluid)

Notable about this technology:

- Particularly suitable for smaller gas-oil separation plants where it may be challenging to make the investment case for installing compressors. A suitable high-pressure medium that can be used to suction for the flare gas may often be available at such facilities in the form of existing fuel gas supply or water pumps.
- The absence of moving parts in the compression zone reduces the need for maintenance and spare parts significantly.
- Ejectors are simple to install and can handle a wide range of process conditions.
- Up to 150:1 compression ratio can be achieved.
- Ability to handle both solids (such as sand), liquid slugs, and sour gases.
- Compact size.
- Zeeco stated that ejectors, even when they use a water loop system, are more efficient than liquid ring compressors.

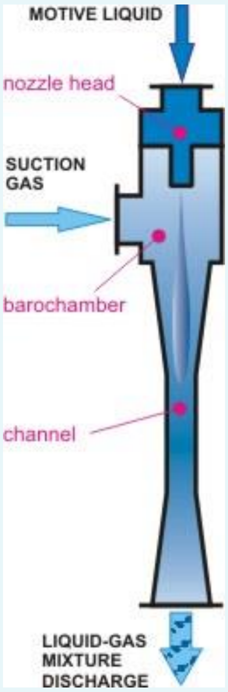


Figure: schematic diagram of a gas ejector. Source: www.hijet.com

[84] Ejector Technology for Efficient and Cost Effective Flare Gas Recovery, Zeeco, 2016.

Notable limitations: • Low volumetric efficiency compared to some compression technologies. • Ejectors require access to a motive fluid at sufficient pressure and flowrate. • Noise reduction measures may be required for gas ejectors, for example acoustic cladding or inline silencers.	
Capacity range (MMSCFD)	Typical size quoted by one supplier: 2 MMSCFD with 7.5 bar discharge pressure. A case study demonstrated applicability at 0.2 MMSCFD Min size: 0.1 MMSCFD
Type of product produced	Pressurized gas stream
Amount of yield per MMSCF gas	N/A
Pre-treatment requirements	Little to no pre-treatment requirement. Nevertheless, since ejectors are not the ultimate technology in the system, pretreatment is required by the final recipient of pressurized gas.
Modularity	Yes
Other scalability potential	Highly scalable
Auxiliary/additional utilities required	Motive fluid. If no sufficiently high-pressure gas is available, a water loop (water pump and handling system) is required.
Applicability (offshore/ onshore)	Both
Ambient temperature limitations	N/A
Minimum feed pressure required	No
Temperature operational range	Not limited by ambient temperatures
Other climatic constraints	None
Other carbon footprint/ environmental impacts	Can help to reduce emissions from flaring as part of FGR system If a water loop is used, appropriate water treatment is required.
Safety Concerns	Important that ejector can be bypassed reliably in the event of a gas surge Noise can be an issue with gas ejectors
Applicability for CCS/CCUS	Not applicable
Other considerations	Gas-water separator required downstream of a water ejector.

4. Net Present Value & Abatement Cost Analysis

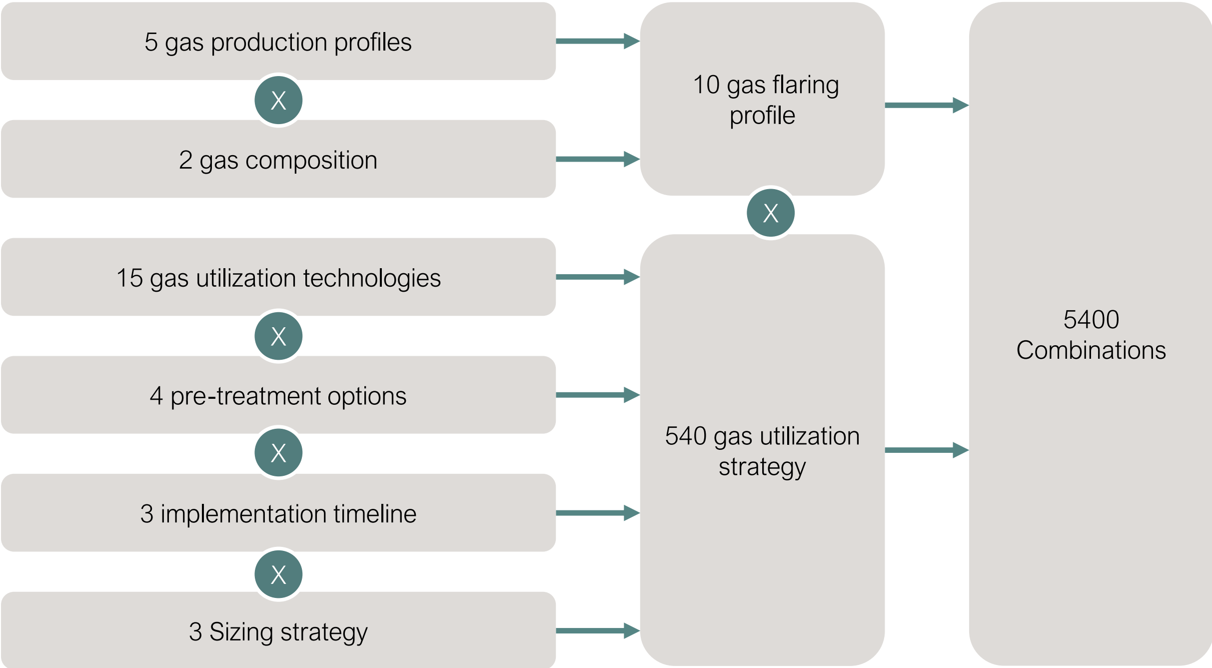
An emission reduction-cost model was built to calculate the economic value (NPV) and greenhouse gas reduction impact of 15 selected utilization options.

In this section the model design and inputs are documented. The first section describes how different scenarios have been constructed. The second part documents the main assumptions, in particular related to the costs and revenue. The third section describes the overall logic for the modelling and finally the results of the simulations are presented.

4.1 Construction of the different scenarios

There are great variations across different associated gas flaring situations, with numerous parameters that can make any flare site a unique case. In addition, there is a great variety of gas utilization strategies. In order to reflect this variety, the project team has constructed 10 different gas flaring scenarios that comprise of 5 different production profiles and 2 gas compositions. In terms of gas utilization options, the project team has developed 540 scenarios, which reflect 15 different gas utilization technologies, 4 pre-treatment options, 3 project implementation time horizons, and 3 sizing strategies. In total, 5400 combinations have been built (Figure 4). Detailed descriptions of each of these variables, and the assumptions made in the model, are presented below.

Figure 4: Overview of the option combinations evaluated by the model



4.1.1 Typical associated gas production profiles

The evolution of AG production evolves over the lifetime of a well/reservoir and depends on the type of reservoir (for example, shale oil reservoirs behave very differently than conventional reservoirs[85]) and also on the oil production strategy. To reflect this variety, the assessments have been performed on five different AG profiles typical for small scale operations.

A profile: a very small flare that gradually but smoothly increases within the first 5 years, followed by a smooth decline,
B profile: a small flare where AG volumes reduce for the first 3-4 years (with significant monthly fluctuations) and then steadily increase,
C profile: a small-medium flare that increases sharply to a plateau in year 4-5, then declines rapidly,
D profile: a medium flare that undergoes a steady increase in AG over the first 7 years followed by a smooth decline.
E profile: a large flare that declines gradually with occasional increases in AG volumes, followed by decreases over the production period (this is typical for oil field development patterns where high GOR wells are shut down and new wells are drilled to keep a high oil plateau).

Table 4: Assumptions on the production profile for five different hypothetical scenarios,

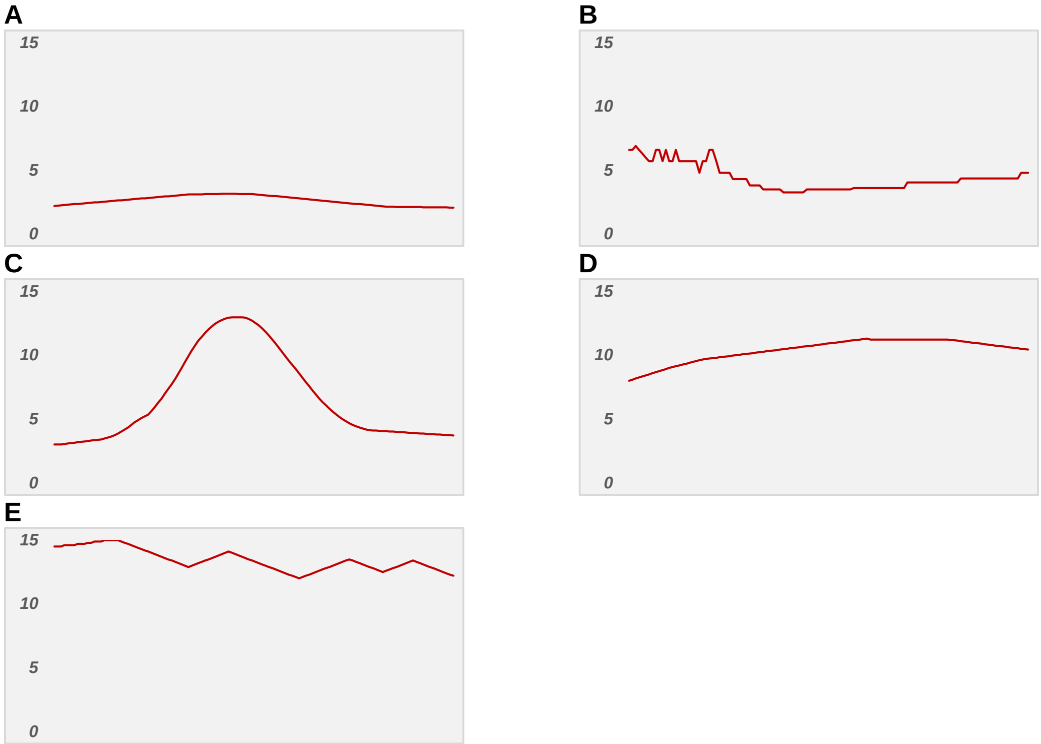
AG profile	Associated gas production (average MMSFD in each year)											
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
A profile	2.3	2.6	2.8	3.0	3.1	2.9	2.6	2.5	2.5	2.5	2.5	2.5
B profile	6.2	5.6	4.9	3.5	3.3	3.5	3.6	4.0	4.2	4.4	4.7	4.9
C profile	3.1	3.7	5.9	10.3	12.7	10.8	7.0	4.5	3.9	3.7	3.5	3.3
D profile	8.3	9.2	9.8	10.2	10.6	11.0	11.1	11.1	10.9	10.5	10.1	9.7
E profile	14.4	14.7	13.8	13.0	13.6	12.6	12.3	13.0	12.7	12.6	11.7	12.3

[85] https://www.carbonlimits.no/project/improving-utilization-of-associated-gas-in-us-tight-oil-fields/

Note: In the model, these production profiles were input on a monthly basis to improve precision. This table only shows the yearly average.

It is important to highlight that other production profiles could result in very different result than the ones presented.

Figure 5: Overview of the 5 different hypothetical production profile scenarios over 10 years



4.1.2 Typical associated gas compositional breakdowns

AG composition is extremely site specific and can vary depending on the reservoir, the production strategy but also sometimes over the production lifetime. For the modelling exercise, two compositions are used, representing a hypothetical rich gas and a hypothetical lean gas. It is important to highlight that other gas composition could result in very different results than the ones presented.

Table 5 - Hypothetical gas composition - two scenario

Component	**Rich gas mol %**	**Lean gas mol %**
C_1	58.7	73.9
C_2	11.9	13.3
C_3	10.3	5.6
NC_4	4.8	2.0
IC_4	4.0	2.3
NC_5	2.6	0.0
IC_5	2.4	0.0
C_6	1.8	0.0
C_7	0.5	0.0
C_8	0.4	0.0
C_9	0.1	0.0
H_2O	0.0	0.1
H_2S	0.5	0.0
CO	1.0	0.0
N_2	0.0	0.0
O_2	0.0	0.0
CO_2	0.9	2.9

Therefore, in combination with the five production profile scenarios, a total of 10 combinations of AG profiles and gas compositions have been modeled: A-Rich, A-Lean, B-Rich, B-Lean, C-Rich, C-Lean, D-Rich, D-Lean, E-Rich and E-Lean.

4.1.3 Selection of utilization technology

As discussed in the section 2, there is currently a wide variety of small-scale gas utilization options at different levels of maturity. In coordination with GGFR, a subset of 15 technologies have been selected for the modelling. The modelling exercise allowed evaluation of the following technologies for each of the above production profiles to calculate the net emission reductions, required CAPEX/OPEX, Net Present Values, abatement costs (i.e., expected CO_2 emission reduction achieved per USD invested). Note: Only direct net emission reductions are included; emissions from end-user use of the products are excluded.

Table 6: Description of utilization options evaluated

	Utilization option	Description of the utilization option	Costs included in the assessment
1	**Mini GPP - full fractionation, dry gas export**	Small scale gas processing unit (see section 3.6); Full fractionation to produce four separate products: dry gas (mostly C_1 & C_2), propane, butane and C_5+ (condensates). Under this utilization option, it is assumed that the dry gas is marketed locally, propane & butane are transported and sold, and condensate is either transported & sold or just blended in the produced crude on site.	Cost of mini-GPP plant (including pre-conditioning of the AG), and dry gas preparation / compression. Product transport costs (dry gas, propane, butane, and condensates) are excluded.
2	**Mini GPP, full fractionation, dry gas flaring**	Small scale gas processing unit (section 3.6). Full fractionation to produce four products (see Option 1 above). The dry gas (mostly C_2 and C_3) is assumed to be flared.	Cost of mini-GPP plant (including pre-conditioning of the AG). Product transport costs (propane, butane, and condensates) are excluded.
3	**Mini GPP, NGL recovery, dry gas flaring**	Small scale gas processing unit (section 3.6); NGL recovery to produce one product: NGL mix (LPG & condensate mix of C_3, C_4 and C_5+). The dry gas (which has lower methane number since more C_3+ compounds remain in it compared to the “full fractionation” option) is assumed to be flared.	Cost of mini-GPP plant (including pre-conditioning of the AG). Product transport costs (NGLs) are excluded.
4	**Mini GPP and NGL recovery (C_3+), dry gas export**	Small scale gas processing unit (section 3.6) NGL recovery to produce NGL mix (LPG & condensate mix of C_3, C_4 and C_5+). See Option 3 above as well as dry gas. The dry gas (which has lower methane number compared to “full fractionation” option) is assumed to be exported in this option.	Cost of mini-GPP plant (including pre-conditioning of the AG), and dry gas preparation / compression. Product transport costs (NGLs and dry gas) are excluded.
5	**Mini CNG – “Virtual Pipelines”**	The main product is CNG in virtual pipeline (trucks), see section 3.9. In cases where NGL removal is required, the NGLs are assumed to be sold as per Option 1 or Option 4.	Cost of mini-CNG plant and AG pretreatment unit(s) (as applicable to the AG composition being assessed). Product transport costs (CNG as the main product, and NGLs as the product of pretreatment) are excluded.

6	**Mini CNG Mobile**	The main product is CNG, see section CNG "Virtual Pipelines" & Mobile CNG Filling Stations3.9. In cases where NGL removal is required, the NGLs are assumed to be sold as per Option 1 or Option 4.	Cost of mini mobile-CNG plant and AG pretreatment unit(s) (as applicable to the AG composition being assessed). Product transport costs (CNG as the main product, and NGLs as the product of pretreatment) are excluded.
7	**Mini GTL**	The main products are liquids such as synthetic diesel, synthetic naphtha, synthetic gasoline. See section 3.3.	Cost of mini-GTL plant and AG pretreatment unit(s) (as applicable to the AG composition being assessed). Product transport costs (synthetic diesel, synthetic naphtha, synthetic gasoline as the main products, and NGLs as the product of pretreatment) are excluded.
8	**Mini GTL (using direct method)**	The main product is methanol, see section CNG "Virtual Pipelines" & Mobile CNG Filling Stations3.4. In cases where NGL removal is required, the NGLs are assumed to be sold as per Option 1 or Option 4.	Cost of mini-GTL plant and AG pretreatment unit(s) (as applicable to the AG composition being assessed). Product transport costs (methanol & ethanol as the main products, and NGLs as the product of pretreatment) are excluded.
9	**Small scale gas engines**	The main product is electricity generated by mini gas engines; (see section 0). If NGL removal is required, the NGLs yielded are assumed to be sold as per Option 1 or Option 4.	Cost of small-scale gas engine(s) and AG pretreatment unit(s) (as applicable to the AG composition being assessed). Electricity transmission costs are excluded and transport costs for NGLs (as a product of pretreatment) are excluded.
10	**Data centers**	Data centers (section 3.11) located on-site; the main product is cryptocurrency. In cases where NGL removal is required, the NGLs are assumed to be sold as per Option 1 or Option 4.	Cost of data center equipment and mini-genset(s) (including pre-conditioning of the AG). Transport costs for NGLs (as a product of pretreatment) are excluded.
11	**Microturbines**	The main product is electricity (see section 3.7). Typically, little pretreatment is required, but if the AG has too high fraction of heavy components and NGL removal is required, the NGLs are assumed to be sold as per Option 1 or Option 4.	Cost of microturbine(s) and AG pretreatment unit(s) (as applicable to the AG composition being assessed). Electricity transmission costs are excluded and transport costs for NGLs (as a product of pretreatment) are excluded.
12	**Hybrid solutions**	The main product is electricity generated by gas engines, where the electricity is supplied to a consumer/grid at an added value by using batteries to guarantee a fixed supply (see section 3.1). Typically, little pretreatment is required, but if the AG has an overly high fraction of heavy components and NGL removal is required, the NGLs are assumed to be sold as per Option 1 or Option 4.	Cost of hybrid units (genset(s), batteries) and pretreatment unit(s) (as applicable to the AG composition being assessed). Electricity transmission costs are excluded and transport costs for NGLs (as a product of pretreatment) are excluded.
13	**Mini LNG**	The main product is LNG; (see section 3.8). the NGLs yielded are assumed to be sold as per Option 1 or Option 4.	Cost of mini-LNG unit(s) and AG pretreatment unit(s) (as applicable to the AG composition being assessed). Product transport costs (LNG as the main product, and NGLs as the product of pretreatment) are excluded.
14	**Hydrogen production**	The main product is hydrogen (see section 3.2). In cases where NGL removal is required, the NGLs are	Cost of mini-hydrogen plant and AG pretreatment unit(s) (as applicable to the AG composition being assessed).

		assumed to be sold as per Option 1 or Option 4.	Product transport costs (methanol & ethanol as the main products, and NGLs as the product of pretreatment) are excluded.
15	**Small-scale GTC**	The main product is chemicals (e.g., methanol); (see section 3.10). If NGL removal is required, the yielded NGLs are assumed to be sold as per Option 1 or Option 4.	Cost of mini-GTC unit(s) and AG pretreatment unit(s) (as applicable to the AG composition being assessed). Product transport costs (chemicals as the main products, and NGLs as the product of pretreatment) are excluded.

4.1.4 Sizing strategy

As AG production profiles often demonstrate significant variations over time, choosing the optimal sizing when designing a utilization option is critical in balancing the need between emission reduction and financial attractiveness.

Three different simplified "utilization strategies" were assessed selected in the model (the base-case scenario is based on the average rate strategy):

- ***Max rate strategy***: the utilization option is sized according to the maximum AG production rate throughout the forecasted profile. This strategy would maximize gas utilization (and thus the emission reductions) and both CAPEX and OPEX, which may reduce the financial attractiveness due to overcapacity of the facility for much of the project lifetime if AG production declines significantly over time.
- ***Min rate strategy***: the utilization option is sized according to the minimum AG production rate throughout the forecasted profile. This strategy will ensure full use of the facility's capacity throughout the lifetime of the project. This option would lead to minimum emission reduction, but reduces CAPEX and OPEX, generally reduces financial exposure and risk, and improves the payback period on the investment.
- ***Average rate strategy***: utilization option is sized at the average AG production rate throughout the lifetime. This strategy would lead to higher emission reduction compared to the "Min rate strategy" but would result in some overcapacity toward the end of the project lifetime if AG production declines significantly over time. It will require higher CAPEX and OPEX than the Min rate strategy, but lower than the Max rate strategy.

Other strategies could be considered but are not included in the current analysis.

4.1.5 Project implementation time

The lead time between the actual start of investment and the gas utilization project start-up can impact the economic attractivity of a specific project. The modelling exercise has allowed to test three different implementation plans:

- Project implementation over 6 months
- Project implementation over 12 months
- Project implementation over 18 months (66% in year one and 33% in the beginning of the second year).

Dependent on the various combination of profile, strategy, technology deployed, etc.), shorter implementation time results in higher NPV and IRR for a given project.

4.1.6 Pre-treatment requirements

Dependent on the amount of H_2S, CO_2, water content or C_3+ in the associated gas and dependent on the selected utilization technology, the model determines whether H_2S removal (also known as sweetening or desulphurization), CO_2 removal (sometimes referred to as AGR (acid gas removal)), H_2O removal (dehydration) and/or removal of heavy components (C_3+ removal) are required.

The following Table 7 describes the maximum allowed content assumed for H_2S, CO_2, H_2O and C_3+. The values presented in Table 7 are based on interviews with technology providers, and technology reviews as presented in section 0.

Table 7 : assumption on the maximum amount of H_2S, CO_2, H_2O and C3+ depending on the gas utilization technology[86]

Max impurity allowed per technology				
	Max H_2S	Max CO_2	Max H_2O	Max C3+
Mini GPP - full fractionation - dry gas export	0.20%	0.40%	0.20%	100.00%
Mini GPP, full fractionation, dry gas flaring	0.20%	0.40%	0.20%	100.00%
Mini GPP, NGL recovery, dry gas flaring	0.20%	0.40%	0.20%	100.00%
Mini GPP, NGL recovery, dry gas export	0.20%	0.40%	0.20%	100.00%
Mini CNG – "Virtual Pipelines"	0.05%	1.00%	0.20%	5.00%
Mini CNG Mobile	0.05%	1.00%	0.20%	5.00%
Mini GTL	0.15%	1.00%	0.80%	10.00%
Mini GTL - (using direct method)	0.05%	4.00%	4.00%	10.00%
Small scale gas engines	0.15%	20.00%	3.00%	15.00%
Data centers	0.15%	20.00%	3.00%	15.00%
Microturbines	4.00%	40.00%	2.00%	25.00%
Hybrid solutions	0.15%	2.00%	0.80%	25.00%
Mini LNG	0.05%	0.30%	0.03%	5.00%
Hydrogen production	0.15%	0.20%	0.20%	5.00%
Small-scale GTC	0.15%	0.40%	0.20%	5.00%

For each combination of gas utilization technology and AG composition, the requirement for gas pre-treatment has been assessed. When pre-treatment is required, the relevant CAPEX and OPEX for the combination of equipment required (sweetening, AGR, fractionation, dehydration, C_{3+} removal) have been included in the evaluation.

The subsection below provides more details on the selection of the C_3+ removal technology.

4.1.7 Selection of C_3+ pre-treatment option

If the total of heavier components in the AG is beyond a specific technology threshold, removal of C_3+ components is needed. This pre-treatment however can be basic (i.e., NGL removals or just a dehydration drum) or more complex (i.e., full or partial fractionation). The NGL removal requires a lower CAPEX but does not yield propane, butane and C_5+ condensates separately, but a blend of natural gas liquids. The full fractionation pretreatment however is capable of generating marketable C_3, C_4 and condensate but is more cost intensive.

C_3+ pretreatment option	Assumed in the model
Full fractionation	85% of C_3 in the AG stream yielded as marketable propane 85% of C_4 in the AG stream yielded as marketable butane 85% to 95% of C_5+ in the AG stream yielded as marketable condensate The rest go to the dry gas stream, which is sent to the utilization technology, fed into a pipeline for export or flared.
NGL removal	65% of C_3, 65% of C_4 and 85% to 95% of C_5+ in the AG stream yielded as a combined product. NGLs can be blended into the produced crude oil or sent to a gas processing plant by trucks. The rest go to the dry gas stream which shall be sent to the utilization technology, fed into a pipeline for export or flared.

4.2 Assumptions for the Model

4.2.1 Capital costs and operational costs

[86] Source Carbon Limits and Vygon Consulting analysis based on literature review and interviews.

For the analysis, the project team has gathered information on both the CAPEX and OPEX of the various gas utilization technologies. The data collection included literature review, and when possible, costs were gathered during the interviews with technology providers. The data gathering processes revealed very large cost spreads and reasonable low and high estimates based on the best available data at the time of preparation of this study are used for the modeling. A “Highest”, and a “Lowest” estimate of the unit CAPEX are also presented, which represent extreme cases in especially negative or positive circumstances. All costs in this table are US Gulf Coast based equipment costs (i.e., not including installation costs) for projects using 10 MMSCD or more gas.

For estimating CAPEX for units below 10 MMSCFD, CAPEX multipliers are applied to reflect the higher unit CAPEX for smaller units (see Table 13 below). For assessing costs in other geographical regions, regional cost factors are applied, as explained further below in this section of the report (see Table 12).

Table 8: Assumptions for the CAPEX for different gas utilization technologies[87]

CAPEX for utilization technologies					
	Lowest	Low	High	Highest	
Mini GPP - full fractionation - dry gas export	1.2	1.4	1.8	2.0	USD/SCFD
Mini GPP, full fractionation, dry gas flaring	1.0	1.2	1.6	1.8	USD/SCFD
Mini GPP, NGL recovery, dry gas flaring	0.6	0.8	1.0	1.2	USD/SCFD
Mini GPP, NGL recovery, dry gas export	0.8	1.0	1.4	1.6	USD/SCFD
Mini CNG – “Virtual Pipelines”	1.2	1.6	2.0	2.8	USD/SCFD
Mini CNG Mobile	1.2	1.5	2.8	3.5	USD/SCFD
Mini GTL	4.5	6.0	9.0	10.0	USD/SCFD
Mini GTL - (using direct method)	4.0	5.0	8.0	9.0	USD/SCFD
Small scale gas engines	1.5	2.0	3.0	4.0	USD/SCFD
Data centers	23.0	26.0	30.0	34.0	USD/SCFD
Microturbines	3.0	4.5	5.8	6.9	USD/SCFD
Hybrid solutions	2.0	2.5	3.5	4.0	USD/SCFD
Mini LNG	2.0	3.0	5.0	7.5	USD/SCFD
Hydrogen production	8.0	10.0	14.0	18.0	USD/SCFD
Small-scale GTC	8.0	9.0	12.5	16.0	USD/SCFD

Note 1: CAPEX indicated in Table 8 include only equipment costs for each technology. Other costs, e.g., shipping, engineering, and installation costs, as well as costs of pre-treatment and gas purification are presented in tables Table 9 to Table 12. They also exclude CAPEX for transport of products to the consumer/purchaser (as explained in detail in Table 6).
Note 2: Shipping and installation costs should be added to the CAPEX data in Table 8.

The following table presents the range of OPEX assumptions related to each of the 15 gas utilization technologies for the model.

Table 9: Assumptions for the OPEX for different gas utilization technologies[88]

OPEX for utilization technologies* **					
	Lowest	Low	High	Highest	
Mini GPP - full fractionation - dry gas export	0.5	0.7	0.9	1.2	USD/MSCF
Mini GPP, full fractionation, dry gas flaring	0.5	0.7	0.9	1.2	USD/MSCF
Mini GPP, NGL recovery, dry gas flaring	0.2	0.3	0.5	0.8	USD/MSCF
Mini GPP, NGL recovery, dry gas export	0.5	0.7	0.9	1.2	USD/MSCF
Mini CNG – “Virtual Pipelines”	1.0	1.2	1.7	1.9	USD/MSCF
Mini CNG Mobile	1.0	1.2	1.7	1.9	USD/MSCF
Mini GTL	1.0	1.2	1.9	2.1	USD/MSCF

[87] Source Carbon Limits analysis based on literature review and interviews
[88] Source Carbon Limits analysis based on literature review and interviews

Mini GTL - (using direct method)	0.6	0.9	1.5	1.8	USD/MSCF
Small scale gas engines	0.5	0.7	0.9	1.2	USD/MSCF
Data centers	1.2	1.4	1.8	2.0	USD/MSCF
Microturbines	0.7	0.9	1.2	1.4	USD/MSCF
Hybrid solutions	0.6	1.0	1.3	1.5	USD/MSCF
Mini LNG	1.5	1.9	2.3	2.6	USD/MSCF
Hydrogen production	1.0	1.2	1.4	1.5	USD/MSCF
Small-scale GTC	1.0	1.2	1.4	1.5	USD/MSCF

Note 1: The OPEX indicated in this table excludes cost of transporting products to consumers, as transport costs are reflected in product prices (netback value, see Table 14).
Note 2: The OPEX indicated in this table doesn't include any cost of purchasing feedgas. This study assumes zero cost of purchasing associated gas.

As discussed in the section above, gas pre-treatment is assumed where required for some combinations of gas composition and gas utilization technology.

Table 10: Assumptions for NGL removal

CAPEX for NGL Removal (Pretreatment)					
	Lowest	Low	High	Highest	
NGLs removal	0.6	0.8	1.0	1.2	USD/SCFD
Full fractionation	1.0	1.2	1.6	1.8	USD/SCFD
Dehydration	0.2	0.3	0.4	0.5	USD/SCFD
OPEX for NGL Removal (Pretreatment)					
	Lowest	Low	High	Highest	
NGLs removal	0.15	0.30	0.50	0.80	USD/MSCF
Full fractionation	0.50	0.70	0.90	1.20	USD/MSCF
Dehydration	0.15	0.20	0.30	0.40	USD/MSCF

Table 11: Assumptions for impurity removal

	Lowest	Low	High	Highest	
CAPEX for H_2S Removal	0.4	0.65	0.85	1.0	USD/SCFD
OPEX for H_2S Removal	0.5	0.7	0.9	1.1	USD/MSCF
CAPEX for CO_2 Removal	0.4	0.65	0.85	1.0	USD/SCFD
OPEX for CO_2 Removal	0.5	0.7	0.9	1.1	USD/MSCF

In order to account for shipping and installations costs, a 'CAPEX multiplier' (to be applied to the "US Gulf Coast" estimates) is assumed, it's magnitude depending on where in the world the utilization option is to be deployed. In addition, to address the country/regional aspect of project risk, the discount factors (a key variable in NPV calculation) applied is varied to account for assessed risk in different countries/regions. These factors are presented in Table 12 below[89].

Note that the regional CAPEX factor results from multiplying the estimated shipping and installation costs. For example, a 1.68 regional cost factor means 68% is added to a technology's "US Gulf Coast" equipment cost estimate to calculate the installed CAPEX in a given geographical region.

Table 12 - The multiplier factor (CAPEX factor) and discount rate assumed for the different regions

Region	**Shipping Costs***	**Installation Costs****	**Regional CAPEX factor**	**Discount rate*****
North America	1.1	1.25	1.38	7%
South America	1.3	1.25	1.63	10%

[89] It should be noted that the for individual case-studies, specific installation costs, shipping costs, discount rates and CAPEX factors should be used, instead of default multipliers/factors and the default discount rates used in this study.

Europe	1.2	1.25	1.50	7%
Africa (normal risk)	1.4	1.25	1.75	10%
Africa (high risk)	1.5	1.25	1.88	14%
West Asia (normal risk)	1.3	1.25	1.63	12%
West Asia (high risk)	1.3	1.25	1.63	12%
Central Asia	1.4	1.25	1.75	10%
East Asia	1.3	1.25	1.63	8%
South Asia	1.3	1.25	1.63	10%
Oceania	1.2	1.25	1.50	7%

[*] Shipping costs are indicative; and are roughly based on distances from major locations where majority of suppliers are generally located, i.e., North America, Europe and East Asia. Individual project analysis requires specific shipping cost assessment from the specific supplier.
[**] Installation costs of 25% of CAPEX is consistently assumed for all regions.
[***] The regional discount rates are averages for each region based on UNFCCC Guidelines on the Assessment of Investment Analysis and NYU Equity Risk Premiums by country . Nevertheless, within each region there are variations from country to country, therefore, for individual project analysis a specific discount rate for the country should be used.

Economy of scale

As specified in section 4.2.1 above, the estimated CAPEX for the various utilization technologies in Table 8 are for equipment with 10 - 15 MMSCFD capacity. Generally, unit CAPEX increases with reduced capacity, due to less favorable economies of scale. Supplier outreach performed for this study demonstrated however that this increase in unit CAPEX is not at the same rate for all technologies. Table 13 below demonstrates the scaling factors used in this study for different categories of the technologies at different capacities.

Table 13 - Scaling factor for five different categories of the technologies evaluated in this report

	CNG/ Hydrogen	LNG	GPP/GTL	PowerGen/Data	GTC
<1 MMSCFD	2.25	2	1.8	1.5	1.8
<3 MMSCFD	1.9	1.75	1.5	1.2	1.5
<5 MMSCFD	1.6	1.4	1.2	1.1	1.2
<10 MMSCFD	1.25	1.25	1.1	1.05	1.1
<15 MMSCFD	1	1	1	1	1

It should be noted that these scaling factors indicated in Table 13 do not represent a universal rule, and individual investment cases require specific assessment of unit CAPEX taking into account the circumstances of the project, AG composition, market conditions, etc.

4.2.2 Product values

Finally, the following table provides an overview of the assumptions related to the product value. Product value may vary significantly over time, but also depending on the geographical location. For the purpose of the modelling, these are assumed constant over time and independent of geographical location.

Note that the product prices in Table 10 are “netback values” at the project outlet location. Netback values are reduced market prices that reflect transport costs of the products to end consumers. The lowest netback value represents facilities with long distances to market where transport costs of the products are high and thus product prices at the project location are significantly lower than the market price. For example, dry pipeline gas has a very low value at stranded assets at large distances from residential/industrial consumers of natural gas.

Table 14: Assumed product prices (netback values)

	Product prices (netback values)					
Product	**Lowest**	**Low**	**High**	**Highest**	**Unit**	**Remarks**
Dry gas to pipeline	0.80	1.13	2.25	6.00	USD/ MSCF	Typical natural gas spot prices are adjusted for transportation costs from the typical upstream locations. Closer to a market, higher netback product value is expected.
Propane (C_3)	125	165	280	440	USD/ tonne	The netback value (after discounting for transport costs to marketing point) have been assumed. The "Highest" assumption is for situations where the site is nearby a C_3/C_4 consumer.
Butane (C_4) extracted:	135	175	300	450	USD/ tonne	
Condensate extracted:	150	220	350	500	USD/ tonne	Condensates could be transported and sold (and so a 20% to 60% reduction is applied, dependent on the distance to calculate the netback value; or can be blended to the crude oil on the site.
MWh output	28.0	45.0	60.0	100.0	USD/ MWh	The wholesale power prices are assumed with a reduction applied for transmission costs. The "Lowest" reflect very remote locations, and the "Highest" represent a site adjacent to a grid or an end user.
Mobile CNG	3.0	3.8	6.8	12.0	USD/ MSCF	The netback values reflect transport costs (which could be extremely variable dependent on the distance), in the "Lowest" to the "Highest" price assumptions.
CNG in truck	3.0	3.8	6.8	12.0	USD/ MSCF	
Bitcoin	15,000	20,000	40,000	60,000	USD/ BTC	While cryptocurrencies are not location dependent, but they experience extreme volatilities, reflected in the "Lowest" to the "Highest" price assumptions.
LNG	200	275	500	700	USD/ tonne	Transport costs are typically high, resulting in significantly lower netback value in the "Low" and "Lowest" cases. In addition, LNG prices are very variable dependent on the region.
Synthetic Diesel	225	325	500	650	USD/ tonne	The "Highest" value represents situations where diesel/ naphtha/gasoline is used on-site to displace the diesel/ naphtha/ gasoline previously purchased, or where an end user is nearby. The "Lowest" value reflects remote flare sites with high transport costs.
Synthetic Naphtha	225	325	500	650	USD/ tonne	
Synthetic Gasoline	250	350	550	700	USD/ tonne	
Hydrogen	350	600	800	1,000	USD/ tonne	Transport costs are typically high, resulting in significantly lower netback values in the "Low" and "Lowest" cases. In addition, methanol prices are very variable dependent on the region.
Chemical	275	350	500	800	USD/ tonne	
Methanol	275	350	500	800	USD/ tonne	The "Highest" value represents situations where methanol can be used on-site to displace the previously purchased methanol, or where an end user is at the close distance. The "Lowest" value reflects remote flare sites with high transport costs.
MWh electricity generated and stored	35.0	54.1	64.9	126.0	USD/ MWh	Continuity of supply results in higher prices for battery-stored electricity compared to the "MWh output" option above
MWh engine output	28.0	45.0	60.0	100.0	USD/ MWh	Similar to 'MWh output' above in this table.

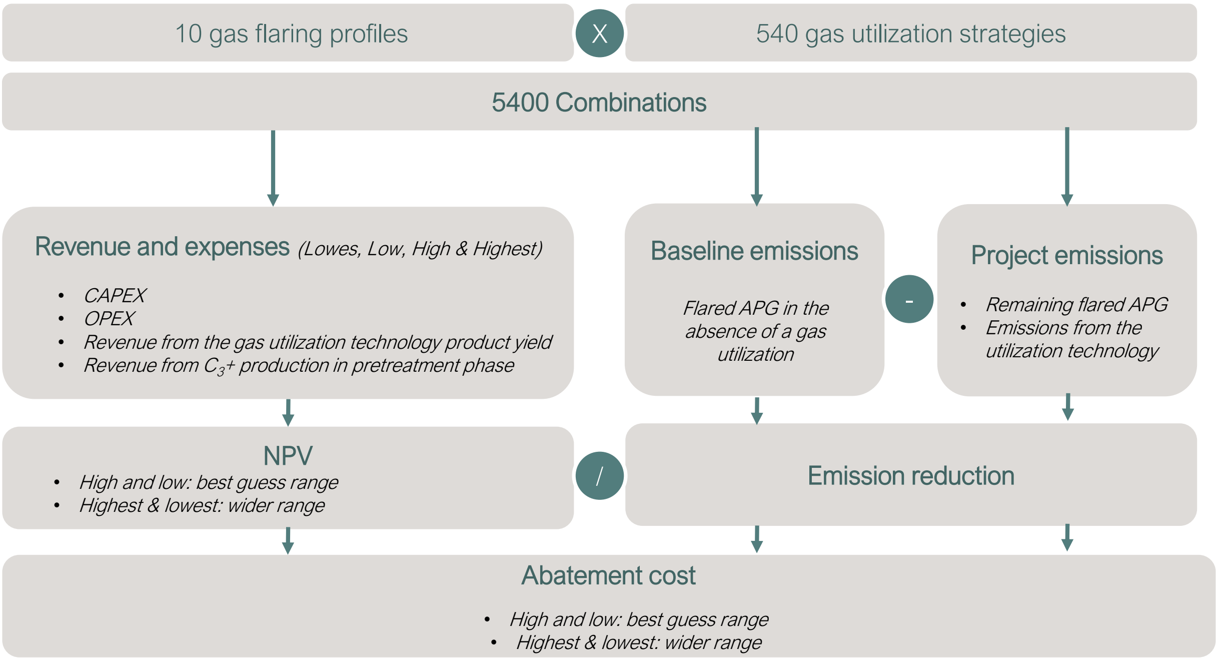
4.2.3 Technology yields

Information provided in the relevant technology description tables in section 33 was used in the model as input for the product yield per utilization option.

5. Model structure

For the 5400 combinations constructed (section 4.1), the model calculates the abatement cost of the gas utilization technology. The following figure presents the overall structure of the model, which is described further below:

Figure 6: Overview of the model structure



5.1 NPV (and IRR) calculation

The model uses cashflow analysis to calculate the net present value (NPV) and internal rate of return (IRR). Cashflows extend over 10 years of the project activity lifetime and takes into account the project costs (based on the OPEX and share of CAPEX for each month), and the project revenue (based on the amount of product yields and the value of each product). No residual capital value is ascribed for the facilities at the end if the project lifetime.

The revenues and costs elements (broken down per month to improve precision, thus evaluated as a total of 120 months) are a function of:

- selected production profile,
- selected gas composition,
- pre-treatment requirement (automatically selected based on the requirement for the final utilization option),
- selected project implementation time (CAPEX distribution over time),
- selected utilization strategy (min rate, max rate or average rate),
- specific technology assumptions (product yield per MMSCF of feedgas),
- product values (automatically selected).

Although the modelling exercise in study evaluates various scenarios based on a predefined variety of input parameters (e.g., the 10 pre-defined production profile-AG composition breakdowns, a range of product prices, various sizing strategies, etc.), nevertheless, each specific utilization project would require a specific techno economic assessment to improve confidence in the final results.

Through the NPV calculation, “High”, “Low”, “Highest” and “Lowest” cases are calculated reflecting the high, low, highest and lowest assumptions presented in the section 4.2[90]. A discount rate is assumed for each case as per Table 12. No inflation, exchange rate to local currency, or tax is considered for either costs or revenues.

5.2 Emission reduction calculations

Emission reductions over time are calculated for each scenario by comparing:

- The baseline emissions: For each AG composition, an emission factor has been calculated using AGA 8 factors taking to account the mole fraction of each component. The total emissions for the baseline scenario are then calculated
- The emissions in the ‘project scenarios’ include the remaining flaring as well as emissions from energy needs for operating each utilization option: In the min and avg utilization sizing strategies some or a major fraction of the AG respectively continues to be flared.

Emissions from displaced energy sources as a result of implementation of the gas utilization technologies are not considered. It has been assumed that the gas utilization technology displaces another project producing the same product with a similar footprint per amount of product.[91]

5.3 Abatement cost

Finally. the abatement cost expressed in USD/tCO_2 is calculated as a function of the NPV and of the emission reduction using the following formula.

$$\textbf{Abatement cost} = \frac{-\,(\textbf{NPV of the cashflow over the project lifetime})}{\textbf{Sum of the emission reduction over the project lifetime}}$$

6. Results

In this section, results of the abatement cost analysis modelling exercise are presented. The C-Rich profile with average rate strategy has been selected to construct the “base-case” scenario. The impact of various changes, including changing the gas profile, the design strategy, the geography, the project implementation time, carbon pricing, and other variable are evaluated as sensitivities.

6.1 Base-case scenario

Table 15 presents the specifications of the selected “base-case” scenario. This base-case represents a ‘typical’ production profile (an increase in the first few years, followed by a decline), and assumes the location to be onshore-North America, with project sizing based on average gas rate, and project utilization fully implemented within 1 year.

Table 15 - Building the base-case scenario

Production profile:	C-Rich

[90] The “Highest” resulted NPV is the result of the Lowest CAPEX/OPEX and the Highest product values from the range. Similarly, the “Lowest” NPV is the result of the Highest CAPEX/OPEX and the Lowest assumption for product values.
[91] This assumption could vary depending on the product but more importantly the geography and the time of the assessment. These variations are not modeled in this study.

Project Lifetime:	120 months (i.e. 10 years)
CAPEX breakdown:	CAPEX spent in first 12 months (one year construction time)
Project location:	North America
Offshore/Onshore:	Onshore
Strategy:	Project size based on average gas rate
Carbon price:	0 USD flare penalties/carbon tax

The C-Profile[92] was selected to represent the base-case scenario since it reflects one of the typical associated gas production profiles: a significant increase in the first few years, followed with a gradual decline in AG production. The gas volumes also represent a typical small-scale situation, with an average rate of 6.4 MMSCFD, a max rate of 13.0 MMSCFD, and a min rate 3.3 MMSCFD). The average rate option was selected for the analysis as a "central case".

The results of the abatement costs analysis for the profile with base-case assumptions are shown in Figure 7.

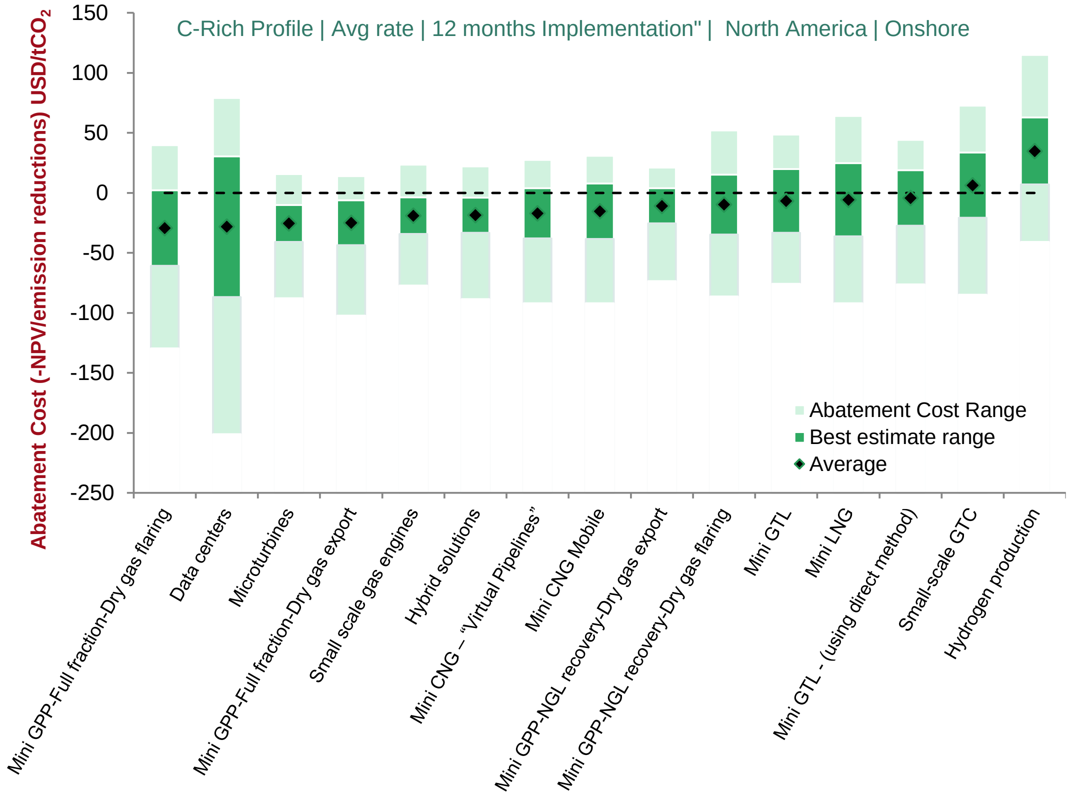


Figure 7 - Abatement cost analysis for the Base-Case scenario (C-Rich profile - Average rate strategy, North America Onshore, no carbon pricing instrument).

As it can be seen, the average best estimate range for the abatement cost indicates projects with positive NPV (negative abatement cost) for the majority of technologies assessed. In addition, all of the technologies assessed (except for hydrogen production[93]) have a "High" estimate abatement cost below 50 USD/tCO_2 (best estimate range - dark green ribbon). The wider abatement cost range (light green ribbon), which assume the widest high/low ranges of costs/prices, demonstrates that for all the technologies there are situations where negative net abatement costs (i.e., positive NPVs) are achievable. These cases represent:

[92] Ref. Sections 4.1.1 and 0.

[93] Note: Hydrogen production from associated gas has not been extensively commercialized, and therefore the estimated CAPEX/OPEX are currently relatively high. It is expected that with future advancement and upcoming implementations, the technology will become less cost intensive.

- situations where the CAPEX can be minimized (e.g., by identifying a supplier that could provide a standardized solution that reduces design costs), and,
- cases where the higher end of the product value range can be achieved (e.g., local demand),
- cases where other cost reductions can be achieved (e.g., reduced operational cost due to shorter product transport distances, use of existing infrastructure, etc.).

While abatement cost is a key indicator for attractiveness of an investment in a utilization option, other financial factors, such as the total required capital also play an important role in decision making. Figure 8 below illustrates the average estimated CAPEX (average of the low and the high estimates) for each of the utilization technologies vs. the average estimated abatement cost.

As it can be observed, the average best estimate total CAPEX for most options for the base-case scenario (C-Rich, with average rate of 6.7 MMSCFD) is between ~20 and ~80 million USD, with some technologies requiring above 100 million USD for capital expenditure. It is notable that data centers are very capital intensive but can be an attractive option under certain circumstances (refer to Figure 7 where the best estimate range for data centers demonstrates the widest abatement cost ranges, mainly due to the assumed high volatility in cryptocurrency values).

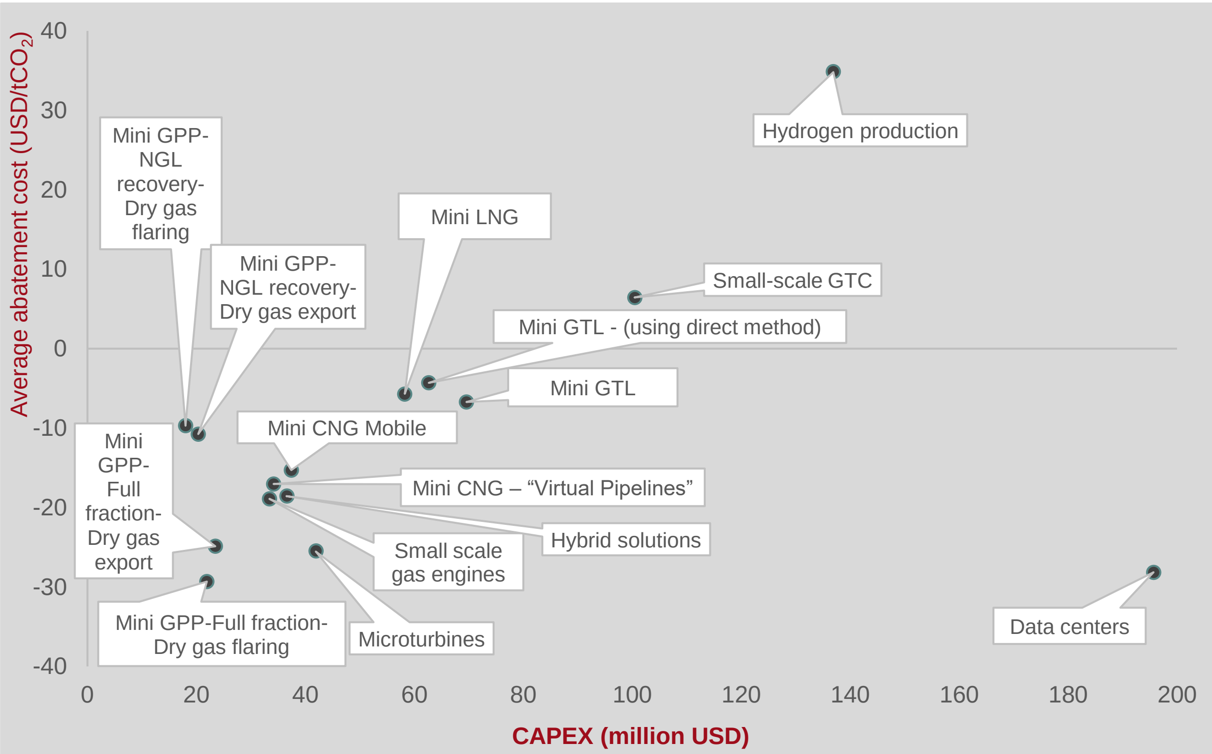


Figure 8 - Estimated CAPEX (average of the low estimate and the high estimate) per utilization technology for the base-case scenario.

Impact of gas composition

In order to evaluate the impact of a leaner gas composition on the financial attractiveness of the utilization options, the C-Lean profile was assessed, with other assumptions similar to the base-case. The results are presented in Figure 9.

As expected, the results demonstrate significantly poorer financial attractiveness for almost all the utilization options in comparison to the base-case (C-Rich), although the overall risk for implementation appears to be lower (smaller dark green ribbon), as with the lean gas projects, risks associated with in variations in NGL prices are less significant.

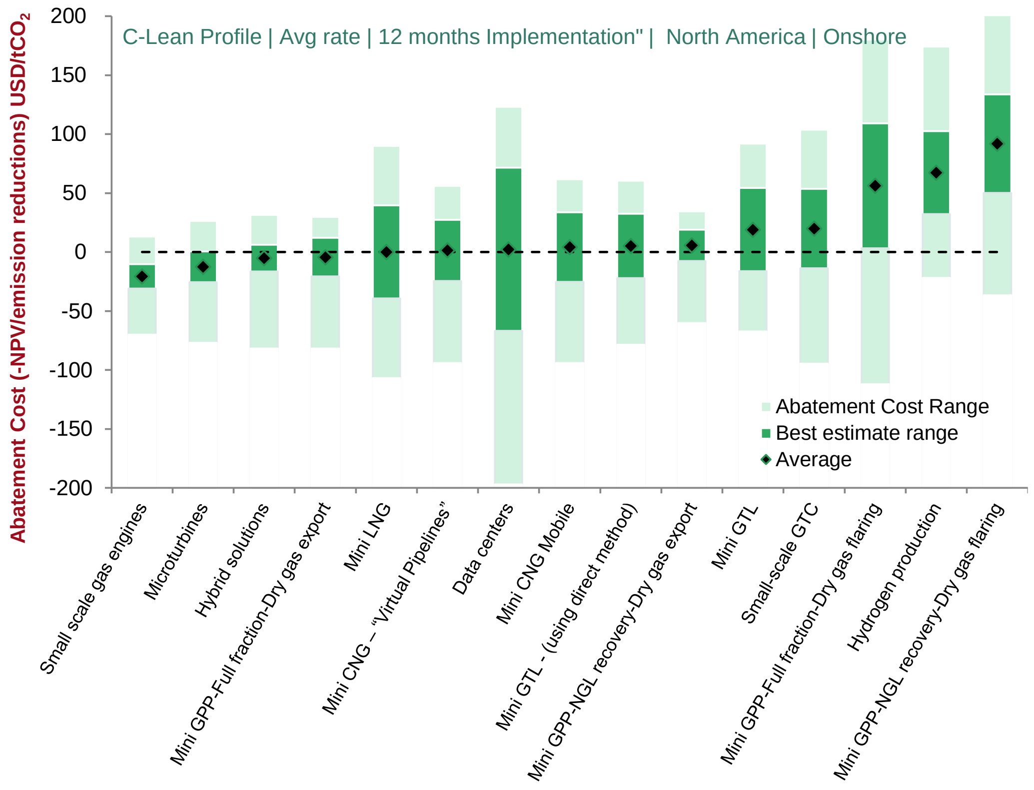


Figure 9 - Estimated abatement cost (average of the low estimate and the high estimate) per utilization technology for the base-case scenario, with gas composition changed to "Lean".

As expected, the mini GPP/NGL recovery utilization options demonstrate the largest drop in NPV, as a great reliance is placed on the C_3+ revenues for these options.

Impact of associated gas volume and the variability of the production profile

In addition to the gas composition, the volume of associated gas and the pattern of its variation over time has a major impact on the attractiveness of all the utilization options. This can be observed by comparing the results of the analysis for the 5 production profiles, as illustrated in Figure 10 below (reference to Section 4.1.1). Table 16 presents the results for A-Rich, B-Rich, C-Rich (base-case), D-Rich and E-Rich profiles, while other assumptions remain the same.

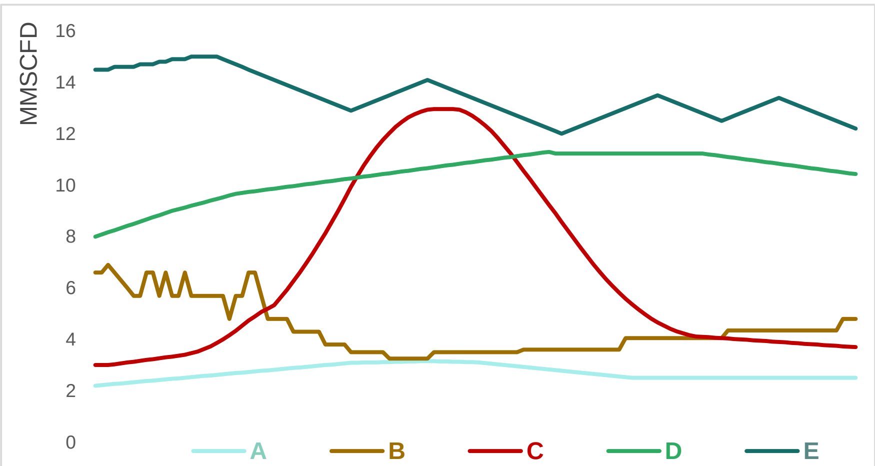


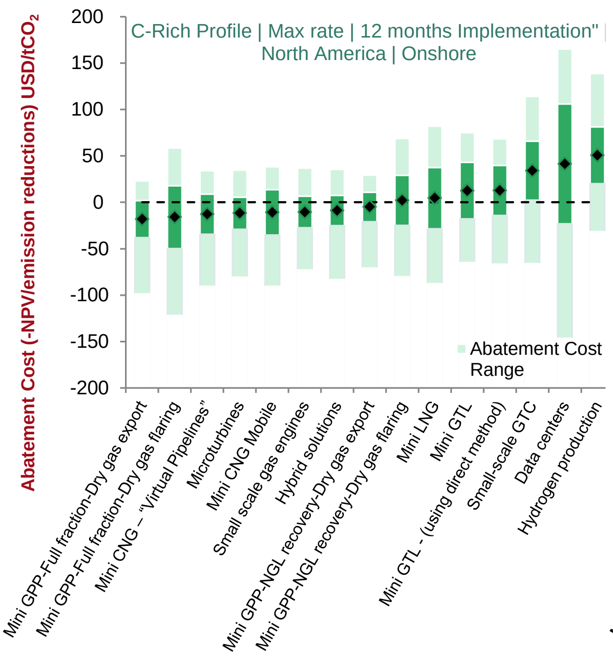
Figure 10 - Comparison of the five production profiles assessed

The production profiles with higher volumes consistently result in lower abatement costs and higher NPVs compared to the lower volume profiles. The contrast is more evident for some utilization technologies, e.g., Mini-LNG, Mini-GTL/GTC solutions, where the most of the higher volume-profiles demonstrate positive average NPVs (i.e., negative “average best estimate abatement costs”.

Table 16 - Comparing abatement cost for the 5 different production profiles in USD (other assumptions are unchanged from the base-case)

	A-Rich	B-Rich	C-Rich	D-Rich	E-Rich
Mini GPP-Full Fractionation-Dry gas export	-21	-24	-25	-26	-27
Mini GPP-Full Fractionation-Dry gas flaring	-23	-28	-29	-33	-33
Mini GPP-NGL recovery-Dry gas flaring	-4	-9	-10	-14	-14
Mini GPP-NGL recovery-Dry gas export	-8	-10	-11	-12	-12
Mini CNG – “Virtual Pipelines”	-14	-17	-17	-21	-23
Mini CNG Mobile	-12	-16	-15	-19	-22
Mini GTL	2	-7	-7	-11	-14
Mini GTL - (using direct method)	3	-5	-4	-8	-11
Small scale gas engines	-17	-19	-19	-21	-22
Data centers	-17	-26	-28	-32	-37
Microturbines	-23	-25	-25	-26	-28
Hybrid solutions	-17	-19	-19	-21	-22
Mini LNG	0	-7	-6	-11	-15
Hydrogen production	47	34	35	19	9
Small-scale GTC	18	6	6	1	-4

The difference between the results for the two production profiles can be better highlighted by looking at the comparing the abatement cost curves of the “C-Rich” and “E-Rich” profiles when both are set to “Max rate” strategy, as demonstrated in Figure 11.



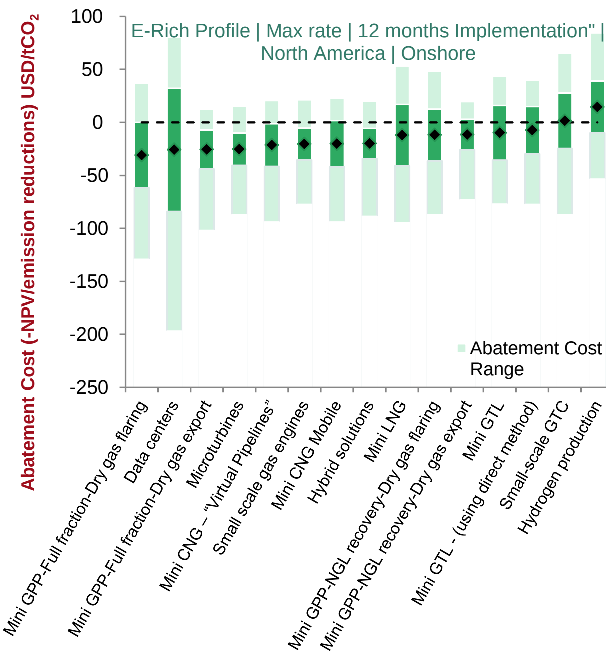


Figure 11 - Estimated abatement cost (average of the low estimate and the high estimate) per utilization technology for the “C-Rich-Max” (left) and “E-Rich-Max” (right)

There are two main reasons for the lower abatement costs for the E-Rich-Max scenario as compared to the C-Rich-Max: a) lower gas volumes in the C-profile leading to less attractive economies of scale, and b) lower variation in the E-profile over the project lifetime.

Impact of changing the project design capacity: Min rate and Max strategies

The base-case scenario employs the "average range strategy" for the abatement cost analysis. The developer however may choose to opt for a different strategy, i.e., either design the utilization option so that a minimum supply of feed gas amount is guaranteed throughout the project lifetime (the "Min rate strategy"), or to opt for the "Max rate strategy" where all of the flared gas is utilized and thus maximum emission reduction is achieved (reference to section 4.1.4).

The estimated abatement costs and CAPEX for the C-Rich profile under the three different design strategies are presented in Table 17 below. The average-rate strategy improves abatement costs for most of the utilization options, in particular for those which enjoy a greater revenue gain from a larger scale implementation[94].

The max-rate strategy consistently results in higher abatement costs (i.e., lower NPV) for the C-profile. This is because designing for the peak gas rate significantly increases the CAPEX, while the additional revenues and the increased reduction in flaring emissions do not proportionally increase[95].

Table 17 - Comparing abatement cost and average CAPEX for the three utilization design strategies for the C-Rich case

	Abatement Cost			CAPEX		
Utilization option	Min-rate	**Avg-rate**	Max-rate	Min-rate	**Avg-rate**	Max-rate
Mini GPP-Full Fractionation-Dry gas export	-24	-25	-18	15	23	47
Mini GPP-Full Fractionation-Dry gas flaring	-29	-29	-16	14	22	44
Mini GPP-NGL recovery-Dry gas flaring	-10	-10	2	11	18	35
Mini GPP-NGL recovery-Dry gas export	-11	-11	-5	12	20	40
Mini CNG – "Virtual Pipelines"	-16	-17	-13	23	34	55
Mini CNG Mobile	-14	-15	-11	25	37	60
Mini GTL	0	-7	13	52	70	137
Mini GTL - (using direct method)	2	-4	13	46	63	123
Small scale gas engines	-18	-19	-11	21	33	65
Data centers	-18	-28	41	134	196	430
Microturbines	-24	-25	-12	28	42	90
Hybrid solutions	-18	-19	-9	23	37	72
Mini LNG	-2	-6	4	41	58	100
Hydrogen production	46	35	51	99	137	215
Small-scale GTC	16	6	34	75	100	197

Impact of Clustering

The economic viability can be greatly improved through utilizing the combined flows from multiple flare sites within the same company, or even by forming productive partnerships involving multiple operators. This approach is often referred to as "clustering".

Several technical, financial and risk-mitigation benefits derive from clustering supplies of associated gas from multiple flare sites in a single utilization project:

- Reduced unit CAPEX by increasing the project size with resultant economies of scale,
- Reduced fluctuations in gas volumes by combining AG from multiple independent sources,
- Mitigate investment risks and improve financing options through a partnership.

[94] The unit CAPEX for some utilization technologies is reduced by increasing the project scale (e.g., CNG, hydrogen and LNG). For others (such as power generation and GTL technologies), the unit CAPEX doesn't increase as significantly when a lower size is implemented.

[95] For the base-case scenario, the non-proportional increase in the revenues is mainly due to the sharp decline in the feedgas volumes leaving the installed capacity under-utilized in later years. It should be noted that different production profiles may demonstrate a different behavior if the "Max rate" strategy is chosen.

Impact of geographical location

The base-case evaluation assumes North America as the project location. North America is assumed to be the ‘lowest cost’ region, and the base CAPEX estimates are US Gulf Coast estimates. Project implementation in other regions of the planet is assumed to incur higher costs as a result of equipment shipping costs and higher installations costs.

Country/regional risk is also assumed to be higher for projects outside the United States, and higher discount rates have therefore been applied for other geographical regions (reference to Table 12, Section 4.2.1).

The impact of the geographical location is illustrated in Figure 12 below, where the abatement cost ranges are presented for assumed higher-risk regions of Africa on the right, and for North America on the left. The impact of the assumed higher installed costs and higher discount rate is quite significant. For “higher-risk Africa”, most of the utilization options have positive best estimate abatement cost ranges (i.e., for the same AG profile ‘C-Rich’, and under typical circumstances, there are fewer attractive options as compared to North America).

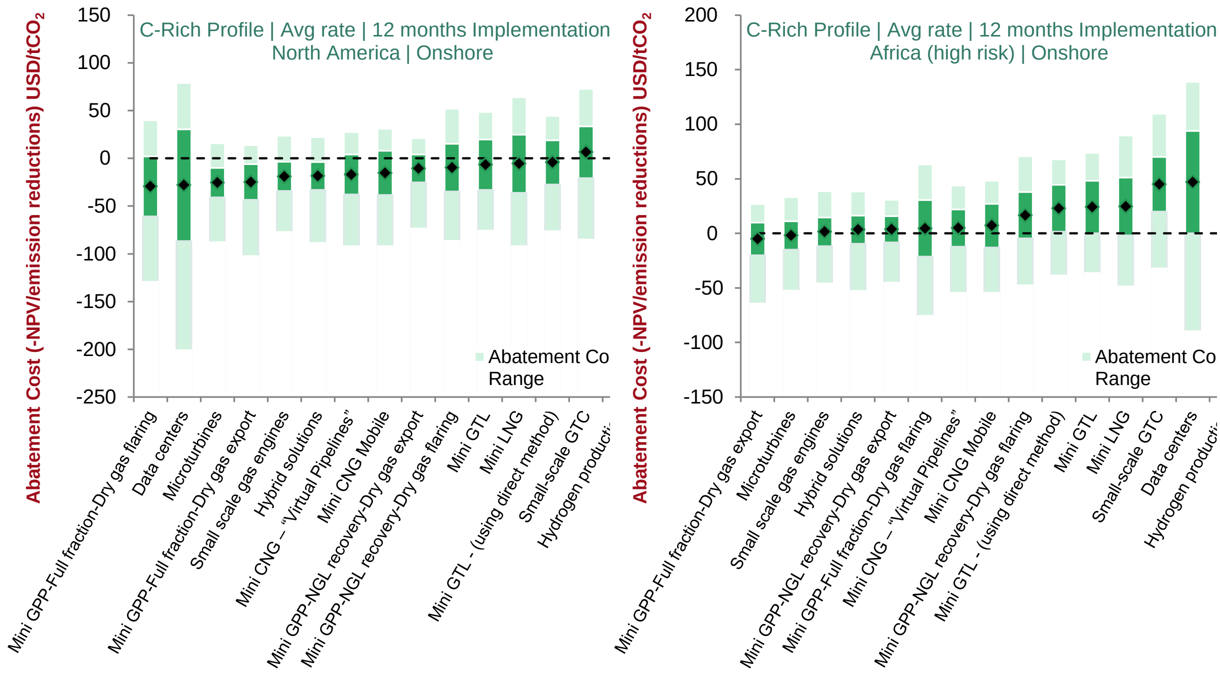


Figure 12 – Abatement cost results for North America on the left and higher-risk Africa on the right

Impact of flaring penalties/carbon tax

The impact of regulation (e.g., flaring penalties or carbon tax) or incentives (carbon credits) is examined in Table 18 below using the C-profile production case for North America (base case scenario) and “higher-risk Africa”.

For both regions, flaring penalties or carbon credits of 10 USD/tCO_2 and 20 USD/tCO_2, are examined.

Table 18 - Impact of flaring penalties/carbon credits on the average best estimate abatement cost for base-case (North America) & "higher-risk Africa"

	North America (base-case)			Africa (higher-risk regions)		
Utilization option	**0** $/tCO₂	**10** $/tCO₂	**20** $/tCO₂	**0** $/tCO₂	**10** $/tCO₂	**20** $/tCO₂
Mini GPP-Full Fractionation-Dry gas export	-25	-32	-39	-5	-10	-15
Mini GPP-Full Fractionation-Dry gas flaring	-29	-36	-43	4	0	-5
Mini GPP-NGL recovery-Dry gas flaring	-10	-17	-23	17	12	7
Mini GPP-NGL recovery-Dry gas export	-11	-18	-24	4	-1	-6
Mini CNG – "Virtual Pipelines"	-17	-24	-31	5	0	-5
Mini CNG Mobile	-15	-22	-29	7	2	-3
Mini GTL	-7	-14	-20	24	19	15
Mini GTL - (using direct method)	-4	-11	-18	23	18	13
Small scale gas engines	-19	-26	-33	1	-3	-8
Data centers	-28	-35	-42	47	42	37
Microturbines	-25	-32	-39	-2	-7	-12
Hybrid solutions	-19	-25	-32	3	-1	-6
Mini LNG	-6	-13	-19	25	20	15
Hydrogen production	35	28	21	77	73	68
Small-scale GTC	6	0	-7	45	40	35

As it is evident, even a 10 USD flaring penalty/carbon tax would make nearly all the utilization technologies for the North America base-case economically attractive.

For "Higher risk Africa", however, under a 10 USD flaring penalty/carbon credit scenario, still most utilization options still demonstrate positive average abatement costs, although a few financially viable options may be identified. With a 20 USD/tCO_2 incentive/penalty[96] however, the best estimate abatement cost range to reach the zero line for the majority of the utilization options.

It should be noted that the potential impact of flaring penalties and/or carbon credit incentives in stimulating utilization of otherwise flared gas would be more pronounced with a "max-rate" strategy. This is because maximum utilization would lead to greater reduction in flaring penalties/carbon tax.

Impact of product prices

The analysis has accounted for a wide range of product prices by assessing the results using on a "highest", a "high", a "low" and a "lowest" input price for each unit of product (reference Table 14, Section, 4.2.2). Nevertheless, prices are often volatile and typically very site dependent. For example, pipeline gas may have a price of close to zero in certain locations (too far from any consumer), while liquid products can experience huge price fluctuations due to changes in market conditions, and also vary considerably depending on site location.

Therefore, for evaluating expected abatement costs & NPVs for specific project in a given location, specific product prices should be used in order to reduce the uncertainty and identify most attractive options more accurately.

An assessment of product price change impact is presented in

[96] The impact of carbon tax can also be assessed in the same way.

Table 19, where the results of a 50% increase in the product values “low” and “high” estimates is applied (except for bitcoin, as it is the only product whose value is not location specific). As it can be seen, this makes all (except one) of the options indicating a negative abatement cost (i.e., a positive NPV).

Table 19 - Impact a 50% increase in product values (except bitcoins) as compared to the base-case (abatement costs below -20 USD/tCO_2 shown in green)

Utilization option	Average of the best estimate abatement cost	
	Base-case	50% higher product values *(except bitcoins)*
Mini GPP-Full Fractionation-Dry gas export	-25	-53
Mini GPP-Full Fractionation-Dry gas flaring	-29	-76
Mini GPP-NGL recovery-Dry gas flaring	-10	-44
Mini GPP-NGL recovery-Dry gas export	-11	-31
Mini CNG – "Virtual Pipelines"	-17	-46
Mini CNG Mobile	-15	-44
Mini GTL	-7	-41
Mini GTL - (using direct method)	-4	-34
Small scale gas engines	-19	-46
Data centers	-28	-42
Microturbines	-25	-55
Hybrid solutions	-19	-47
Mini LNG	-6	-43
Hydrogen production	35	0
Small-scale GTC	6	-32

Impact of other parameters

Reducing or increasing the construction time
Comparing cases with a construction time from 6 months to 1.5 years indicates that a shorter implementation time increases the NPV and reduces the abatement costs. This is most evident for production profiles which reach early plateau production.

Implementation offshore
While not all the technologies have proven offshore implementation track-records at small-scales, those that do have higher CAPEX and OPEX for offshore implementations, primarily due to higher installations costs at offshore locations, assumed in the model to be 25% higher.

Analysis of utilization options deployed offshore under the base-case scenario have abatement costs between 40% and 100% higher compared to similar on-shore utilizations.

7. Case-Studies

7.1 Case 1 - AG processing plant with an in-line gas separation unit

AG processing plant with an in-line gas separation unit supplied by AEROGAS LLC at the S. Balgimbaev field (Kazakhstan)		
Country / Region	Kazakhstan, Atyrau region, S. Balgimbaev field	**Detailed project description** **1. Situation prior to project implementation** AG produced at the S. Balgimbaev field in Kazakhstan was directed to a processing plant capable of handling up to 1.9 MMSCFD, however with the development of the asset and an increase in the production, its capacity turned out to be insufficient to ensure the utilization of additional volumes of AG.
Operator / Technology provider	**Technology provider:** AEROGAS LLC	

	Operator: Embamunaigas JSC
Implementation year	2020-2021
CAPEX – OPEX for the operator	**CAPEX:** 1.1 mln USD[101] **OPEX:** Additional OPEX is minimal and is predominantly related to an increase in electricity consumption, as well as the costs of products transportation by truck.
Achieved emission reductions	Implementation of the project allowed to reduce emissions of pollutants into the atmosphere by 1037 kt of CO_2-eq. per year in comparison with the option of soot-flaring of the additional 3.9 MMSCFD of AG, or by 96 kt of CO_2-eq. per year relative to soot-free flaring
Products	Methane, propane-butane, C_5+
Additional information	Implementation of the project made it possible to increase the volume of AG processing from 1.9 to 5.8 MMSCFD without the construction of additional trains of the

At the same time, the operator did not consider the possibility of flaring due to the strict regulatory measures in force in the country. In particular, in accordance with Article 146 of the Code of the Republic of Kazakhstan “On Subsoil and Subsoil Use”, combustion of raw gas in flares is prohibited. It is allowed only in cases of a threat of emergencies, a threat to the life of personnel or public health and the environment, during testing of well facilities, during trial operation of a field, as in case of technologically inevitable combustion of raw gas.[97]

Therefore, in order to increase the production volume at the field it was required to expand the AG utilization capacity from 1.9 to 5.8 MMSCFD. Initially, the operator considered the possibility of constructing additional trains of the gas processing facility, however the technology provider AEROGAS LLC proposed a more cost-effective solution.

The composition of natural gas at the S. Balgimbaev field is presented in the table below.

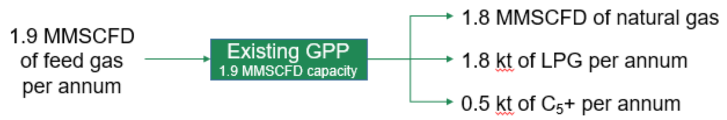
Natural gas composition at the S. Balgimbaev field

Element	Content, mole %
H_2S	0.0%
CO_2	0.0%
N_2	0.7%
CH_4	82.6%
C_2H_6	7.4%
C_3H_8	3.8%
$i\text{-}C_4H_{10}$	0.6%
$n\text{-}C_4H_{10}$	1.2%
$i\text{-}C_5H_{12}$	0.3%
$n\text{-}C_5H_{12}$	0.3%
$C_5+nH_{12}+2(n+1)$	0.2%
Total	**100.0%**

Source: VYGON Consulting based on AEROGAS LLC data

Simplified process block scheme of the APG utilization process prior to project implementation is presented below.

Simplified block scheme of the APG utilization process prior to project implementation at the S. Balgimbaev field



Source: VYGON Consulting based on AEROGAS LLC data

2. Implemented project

Instead of expanding the AG utilization capacity through the construction of new trains of the processing plant, it was decided to install an in-line gas separation unit with a capacity of up to 5.8 MMSCFD, which made it possible to redistribute the product flows and thereby optimize the operation of the installed equipment: liquids are separated from the raw gas flow directly in the in-line separator, after which they are directed to the existing processing facilities. Due to the relatively low content of wet components in AG (the share of methane in volumetric terms is 82.6%), they were sufficient to process the available volumes.

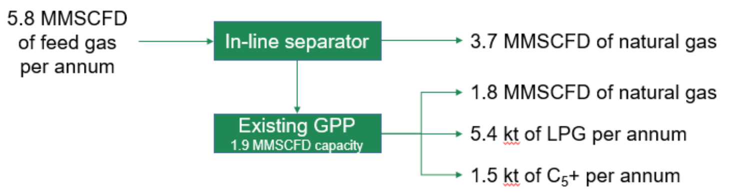
[97] Code of the Republic of Kazakhstan dated 27 December 2017 № 125-VI “On Subsoil and Subsoil Use” (with amendments and additions as of 01.07.2021), article 146, clause 1.
[101] 460 million Kazakh tenge

gas processing facilities, which, in turn, made it possible to significantly reduce the capital costs

Therefore, the capacity of the AG utilization project was actually increased from 1.9 to the target 5.8 MMSCFD without the construction of additional trains.

Simplified process block scheme of the APG utilization process after the project implementation is presented below.

Simplified block scheme of the APG utilization process after the project implementation at the S. Balgimbaev field



Source: VYGON Consulting based on AEROGAS LLC data

3. Project costs

The economic efficiency of the project has been evaluated “as per delta investment”, i.e. the costs of the additional equipment that had been installed as part of its implementation were compared against the achieved gains.

The CAPEX of the installed in-line separator amounted to about 1.1 mln USD. According to the estimates of AEROGAS LLC that developed and supplied the equipment, the implementation of an alternative option – construction of additional trains of the AG processing plant – would have cost 30-50% more.

Additional OPEX associated with the introduction of the in-line separator is minimal and is predominantly related to an increase in electricity consumption: about 10 kW for the air-cooling unit and 5 kW for heating pipes, as well as for power supply for instrumentation. The increase in output of products would also result in higher transportation costs.

Assuming the US Gulf Coast as the location of project implementation the additional electricity costs of electricity would amount to about 6k USD per annum, given the price of 4.4 cents per kWh.[98]

The costs of evacuation of the additional volume of produced natural gas, LPG and C_5+ is accounted for through the value of the product (netback prices of natural gas, LPG and C_5+ are used to evaluate revenue).

The main parameters and assumption of the economic evaluation of the APG utilization project are presented in the table below.

Costs	
CAPEX of the additional equipment, mln USD	1.1
OPEX – power consumption, mln USD p.a.	0.01
OPEX – maintenance, mln USD p.a.	0.01
Cost of APG production, USD / SCFD	0.0
Taxes, mln USD p.a.	0.5
Product values – min	
Natural gas, USD / MSCF	1.13
LPG, USD / tonne	185
C_5+, USD / tonne	200
Product values – max	
Natural gas, USD / MSCF	2.25
LPG, USD / tonne	305

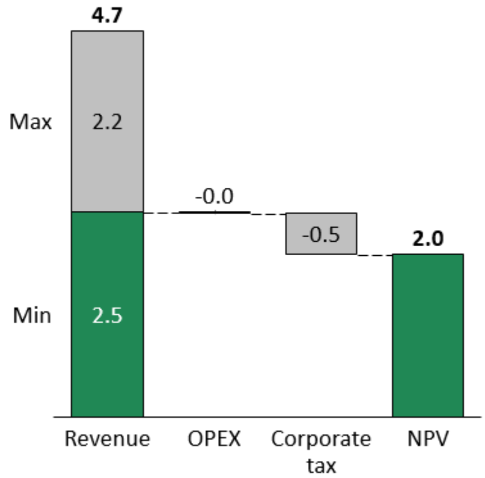
98 US EIA (2021) Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, May 2021 and 2020 (Cents per Kilowatthour). Available at: https://www.eia.gov/state/data.php?sid=TX#Prices

C_5+, USD / tonne	320
Other parameters and assumptions	
WACC, %	7%
Years of available extra gas (assumed)	15

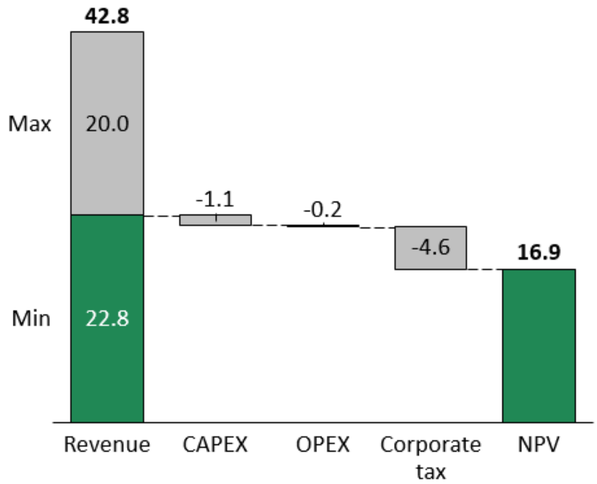
Source: VYGON Consulting based on AEROGAS LLC data

The results of the evaluation of the economic efficiency of the project based on these assumptions are presented in the figure below.

Annual cash flows of the in-line separator unit at the S. Balgimbaev field, mln USD per annum



NPV of the introduction of the in-line separator unit at the S. Balgimbaev field, mln USD



Source: VYGON Consulting based on AEROGAS LLC data

4. Project timeline

The project was implemented in less than one year:

- In March 2020 an agreement for the supply of equipment was concluded with AEROGAS LLC
- In October 2020 the equipment was delivered to the field, construction and installation works began
- In February 2021 new equipment was launched.

5. Product sales market

In accordance with the project, the obtained dry gas flows are planned to be sent to the pipeline for gas supply to nearby towns and villages. The construction of the pipeline was carried out in parallel with the expansion of the AG utilization capacity, however at the time of writing this report it was not completed.

Wet components – propane-butane and C_5+ – are evacuated from the field by trucks, which is facilitated by the developed road infrastructure in the region.

6. Description of the environmental and social benefits of the project

Implementation of the project made it possible to ensure the utilization of additional volumes of AG, which is particularly important for the operator in connection with the aforementioned strict regulation of AG flaring in the Republic of Kazakhstan.

In accordance with our estimate and taking into account the composition of AG produced at the S. Balgimbaev field, the implementation of the project allows to reduce emissions of pollutants into the atmosphere by 1 037 kt of CO_2-eq. per year in comparison with the soot-flaring of the additional 3.9 MMSCFD of AG or 96 kt of CO_2-eq. per year relative to soot-free flaring.

Emissions of pollutants from flaring / utilization of the additional 3.9 MMSCFD of AG per year at the S. Balgimbaev field

Pollutant	Emissions by scenario, t CO_2-eq. per year		
	Soot flaring[99]	Soot-free flaring[100]	AG utilization
CO_2	76 957	93 348	0.0
NO_2	598.3	897.4	49.1
NO	97.2	145.8	8.0
Black carbon	917 796.0	0.0	0.0
CO	16 996	1 360	33
CH_4	23 187.8	397.5	92.5
C_2H_6	629.1	10.8	0.2
C_3H_8	473.7	8.1	0.1
C_4H_{10}	297.5	5.1	0.0
C_5H_{12}	117.7	2.0	0.0
C_6H_{14}	48.5	0.8	0.0
Total	**1 037 198**	**96 175**	**183**

Source: VYGON Consulting based on AEROGAS LLC data

7. Project implementation risks

The financial risks associated with project implementation were minimal due to the fact that the capital costs of the partial steam reforming unit itself, the gas pumping units, with which it was integrated, as well as the costs of repairs and maintenance of the equipment were known in advance.

The cost of AG in the project was assumed to be zero due to the fact that it was produced and consumed on-site with no transportation involved. As a result, there were also no risks associated with fluctuations in the price of feedstock.

[99] Soot flaring is defined as flaring that is accompanied by the emissions of black carbon (soot). It occurs when the combustion of hydrocarbons is incomplete due to insignificant efficiency of the flare.
[100] Soot-free flaring implies complete combustion of hydrocarbons at the flare. It does not result in emissions of black carbon (soot).

7.2 Case 2 - Data center deployed at an oilfield in North Dakota

<table>
<tr><th colspan="3">Data center deployed at an oilfield in North Dakota</th></tr>
<tr><td>Country / Region</td><td>United States, North Dakota</td><td rowspan="7">Detailed project description

1. Situation prior to project implementation

A large public E&P operator drilling horizontal oil and gas wells in North Dakota had access to a gas gathering pipeline system that did not have sufficient capacity to take all of the AG extracted from the 5 wells on the site. The volume of excess gas was variable and dependent on the gas production from all of the other well sites on the gas gathering system. In this situation, the regulator would have allowed the operator to flare the excess AG volumes.

Alternative options, such as gas-to-liquids or CNG, were uneconomic for the operator, as was the expansion of the pipeline capacity for the gas gathering company.

Additionally, the operator did not have access to utility power at the well site, but was able to use a small subset of the excess gas produced to generate power for on-site uses.

2. Implemented project

Crusoe Energy Systems that was servicing the operator installed 3 Digital Flare Mitigation modules, i.e. modular data centers equipped with their own generation capacity, consuming approximately 1 MMSCFD of the otherwise flared AG for at least one year.

The pipeline company was willing to give the operator a release from their gas dedication agreement for 1 MMSCFD for at least 1 year to allow Crusoe Energy Systems to use its Digital Flare Mitigation system to purchase AG and consume it, as opposed to the business-as-usual model involving the AG flaring.

Crusoe Energy Systems took possession of the AG (rich at 1500 BTU) directly from the well head after traveling through a three-phase separator and used it to power the equipment.

In addition, Crusoe Energy Systems paid the operator for the AG as a basis for taxes and royalties which consummated the transfer of custody of the AG, as a result the operator did realize revenue for the gas that would have otherwise been flared.

3. Project costs

The business model applied by Crusoe Energy Systems is based on the conclusion of agreements with field operators on the transfer of ownership rights on produced AG. The company then proceeds to monetize it through the provision of data center services or cryptocurrency mining, while bearing the costs of suppling and operating the equipment.

Therefore, the operator does not carry the capital and operating costs associated with deployment of modular data centers, which makes the proposed solution particularly attractive for fields where there are no alternative AG utilization options.

4. Project timeline

–

5. Product sales market

There are two possible directions of data center monetization:</td></tr>
<tr><td>Operator / Technology provider</td><td>Technology provider: Crusoe Energy Systems

Operator: large public E&P operator</td></tr>
<tr><td>Implementation year</td><td>–</td></tr>
<tr><td>CAPEX – OPEX for the operator</td><td>CAPEX: no costs for the operator

OPEX: no costs for the operator</td></tr>
<tr><td>Achieved emission reductions</td><td>Up to a 63% reduction in CO_2-equivalent GHG emissions compared to AG flaring</td></tr>
<tr><td>Products</td><td>Data center services / cryptocurrencies mining</td></tr>
<tr><td>Additional information</td><td>The operator does not carry the capital and operating costs associated with deployment of modular data centers, which makes the proposed solution particularly attractive for fields where there are no alternative AG utilization options</td></tr>
</table>

		▪ Provision of data center services for external clients, i.e. using the capacity of data centers to solve tasks that require significant computing power. ▪ Cryptocurrency mining. **6. Description of the environmental and social benefits of the project** Because flares do not fully combust methane, Crusoe Energy System's solutions can achieve significant reductions of methane emission and CO_2-equivalent emissions, which the company estimates to be up to a 63% reduction in CO_2-equivalent GHG emissions. **7. Project implementation risks** On part of the operator, there were no significant risks associated with the implementation of the AG utilization project. Since the capital and operating costs are borne by the technology provider, financial risks for the operator are also minimal. On the part of Crusoe Energy Systems, the risks were related to market factors. In the case of APG monetization through the provision of data center services, the company needed to find a consumer of these services and incurred the associated risks. In the case of monetization through cryptocurrency mining, the main risk is the significant volatility of their value, which has a direct impact on the economic efficiency of the project.

Annex I – List of Companies

s
Aerogas
Aspen Engineering Services
Caterpillar
Capstone - Tokyo office
Capstone - UK office
Clarke Energy
Crusoe Energy Systems
Expansion Energy
GasTechno
Gazprom Neft
GazSurf
Greyrock
Houpu Clean Energy
Hygear
Ingevity
INNIO
JGC Corporation
New Technologies LLC (Russia)
OPRA Turbines
Pioneer Energy
Safe Technologies Industrial Group
Zeeco