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Gas Networks Ireland

Within Grid Compression Feasibility Study

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April 2021

Client Gas Networks Ireland

Document Control	
Document Title	Within Grid Compression Feasibility Study
Document Reference	750-01-BG-001
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Document History		
Document Reference	*Revision Date*	*Notes*
750-01-BG-001-A	25th September 2020	Initial draft
750-01-BG-001-B	26th January 2021	Post comments revision
750-01-BG-001-C	22nd February 2021	Final Revision
750-01-BG-001-D	8th April 2021	Publication Revision

Issue Record		
Name	*Company*	*Date Issued*
Jason Hannon	GNI	8th April 2021

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DATE **08/04/2021**	SIGNATURE **MH**	SIGNATURE **CB**	SIGNATURE **JB**

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Executive Summary

Gas Networks Ireland have commissioned CNG Services Ltd (CSL) to carry out a feasibility study into the technical, financial and environment effects of installing gas compressors on their gas network to create capacity for biomethane injection into the 4-bar network. The study constructed a comprehensive Excel spreadsheet model to assess the viability of two biomethane projects in Ireland. The first AD project with a 285 scmh biomethane injection into the Knockroe AGI. The second project with a 500 scmh proposed biomethane injection into the Glebe West AGI.

6 different schemes were assessed for both projects, as summarised in the table below.

Scheme	Description	Comments
1	4 barg Grid	A typical biomethane connection into a local distribution network.
2	70 barg Grid	As scheme 1 but the site connects into a nearby high-pressure transmission pipeline. The site will need on-site compression to achieve network pressure.
3	Virtual Pipeline	The produced biomethane is processed on site and then compressed to 250 bar for transport via CBM trailer. This includes costs for high pressure compression, purchasing CBM trailers and the cost of the decanting station.
4	Within Grid Compression	As scheme 1 however the compression is done at the local AGI to recompress gas into the higher-pressure tiered network.
5	Virtual Pipeline (GNI Ownership Model)	As scheme 3 but the CAPEX and O&M costs of haulage, dispensing and injection into the network is priced as a service GNI sells to a biomethane developer.
6	Within Grid Compression (GNI Ownership Model)	As scheme 4 but the CAPEX and O&M costs of the AGI compressor are borne by GNI. Within Grid compression is then sold to the biomethane developer as a service.

The key findings for both projects are as follows.

Scheme 1 – DX Connection

Scheme 1 is not a viable option for the Knockroe project due to the network demand size. The distribution capacity possible (53%) is too low to be profitable. If not for this, scheme 1 will typically be the most economic scheme provided capacity is restrained by no more than 10%. This is seen in the Glebe West project which shows scheme 1 to be the most economic scheme.

Scheme 2 – TX Connection

The cost of high-pressure pipelines at long distances for scheme 2 make it an unviable solution for either the Knockroe or Glebe West projects. Scheme 2 requires a minimal pipeline to be cost effective. However, for short distances (less than 3km) scheme 2 can be more economic compared to a virtual pipeline or a within grid solution.

Scheme 3 – Virtual Pipeline

The virtual pipeline scheme is unviable for Knockroe but works well for Glebe West. This is due to the Knockroe project not being able to generate enough revenue to minimise the payback period of the daughter station CAPEX. For Glebe West the scheme 3 has a payback period of 11.7 years and is less profitable compared to within grid compression. Generally, in the range of 20 to 42 GWh of biomethane, virtual pipelines are most cost effective when long pipeline distances (30km+) are required for the other schemes. In this range of biomethane transport, the haulage cost is negligible compared to rising pipeline costs.

Scheme 4 – Within Grid Compression

Capacity studies done on the networks for both projects show Knockroe to have a limited capacity compared to Glebe West. This means for a within grid compression solution, compressor runtime for the most cost-effective compressor is larger for Knockroe compared to Glebe West. This results in high load factor for the Knockroe compressor meaning several hours of daily operation as opposed to a couple for Glebe West. With this considered, within grid compression is still feasible for both projects.

Within grid compression works well with Glebe West since there is a large capacity drop from winter to summer. Therefore, the compressor is able to find a balance and operate for a few hours per day during the summer when gas demand is low. The Knockroe project has a low biomethane export flow rate and small size of the local gas network so while feasible it is not as economic. The payback periods for Glebe West and Knockroe for scheme 4 are 7.4 and

20.7 years respectively. Since schemes 1, 2 and 3 are not suitable for Knockroe, the scheme 4, within grid, project is the best amongst them as it will actually generate revenue.

Generally, within-grid is found to be best if the 70 barg connection is away from 3km and the 4 barg network has a constraint of more than 10% and is within 15km of a connection.

Schemes 5 & 6 – GNI Ownership Models

For both projects, a GNI ownership model for either within grid or a virtual pipeline reduces payback period. The GNI ownership models work well for virtual pipeline models due to converting high CAPEX costs of a daughter stations into OPEX. For within grid models GNI ownership sees a diminishing payback difference as biogas production increases and is less cost effective. Smaller sites such as Knockroe see a bigger difference compared to Glebe West whilst not being as good financially. The GNI ownership model works best for small virtual pipeline models but will lose value as the project size increases.

For Knockroe due to the project size, the virtual pipeline solution is cheaper than within grid compression if GNI ownership was considered. For Glebe West, within grid is more economic than virtual pipeline even though the payback difference of using this is only about 1 year.

1 Introduction

1.1 Project Outline

Gas Networks Ireland have commissioned CSL to undertake a feasibility study on installing gas compressors on their gas network to create capacity for biomethane injection into 4 bar pipelines. The study examines the technical feasibility of such a project, the financial cost and the environmental benefits when compared to a standard biomethane injection or transporting biomethane by road to a remote injection point with sufficient capacity.

The GNI network in Ireland has an approximate length of 13,954 km. This includes the 70 bar transmission network (TX) and 4 bar distribution network (DX). Naturally, biomethane generated from anaerobic digestion (AD) is of low pressure and suitable for the 4 bar network without any additional compression. Businesses operating AD sites want to be producing biomethane all year and if injecting into the DX network at these sites, will run into capacity issues during summer periods of low seasonal demand as there may be insufficient capacity.

Compression and injection into the TX network as a solution can be limited due to expensive pipeline costs when distances between biomethane sites and the TX network is sufficiently large. Currently, for such scenarios GNI are developing a virtual solution where gas is compressed to 250 bar and transported by road via trailers. This report proposes and explores within-grid compression as an additional solution, where further cost savings can be found.

The gas networks in Ireland are operated in a 'trickle-down' approach. Gas is imported into the country from either the UK interconnectors or the Corrib offshore gas field. Here the gas is injected into the highest-pressure transmission system at approx. 70 bar. The transmission system transports gas around the country to regional Above Ground Installations (AGI) where gas is then pressure regulated into regional distribution systems. The gas is then further regulated at local Pressure Reduction Stations (PRS) and district governors. Any biomethane injected into a lower pressure tiered network cannot return to the higher-pressure tier and this creates capacity restrictions where new injection points want to connect to their nearest pipeline but there is insufficient demand in the localised network for the gas they wish to inject.

Within grid compression creates capacity within the network. A compressor installed at an Above Ground Installations would be able to take gas from the lower pressure tier network, compress it and transfer it back to the higher-pressure tier network. This would create capacity in the downstream network and allow new injection points to connect where previously there was limited capacity.

GNI proposed two of their sites for CSL to assess the potential of Within Grid Compression. Glebe West AGI on the east coast and Knockroe AGI on the west coast. The capacity restrictions are shown in table 1 below.

Table 1: Flow capacity restrictions for chosen site

GNI Site	**Summer capacity**	**Proposed max injection flowrate**
Glebe West AGI	845 scmh	500 scmh
Knockroe AGI	192 scmh	285 scmh

2 Sites

2.1 Knockroe AGI

For the first project the AD site is proposed to produce 285 scmh of biomethane at 4 bar for grid injection. Indicative summer and winter flow possible are 192 and 1134 scmh.

Approximately 0.41km of DX pipeline would be required to connect to the nearest suitable DX connection and 9.6km of TX pipeline to connect to the nearest TX connection point.

The 2019 seasonal and diurnal gas demand profile for the Knockroe network is shown below. The profile was calculated using given demand data and suggests a normal profile. The network shows a high winter demand and low summer demand. The ability of the gas network to accept biomethane relies on sufficient consumer demand downstream of the injection point. The demand is lowest at night times, and during the summer period when heating load is not applied.

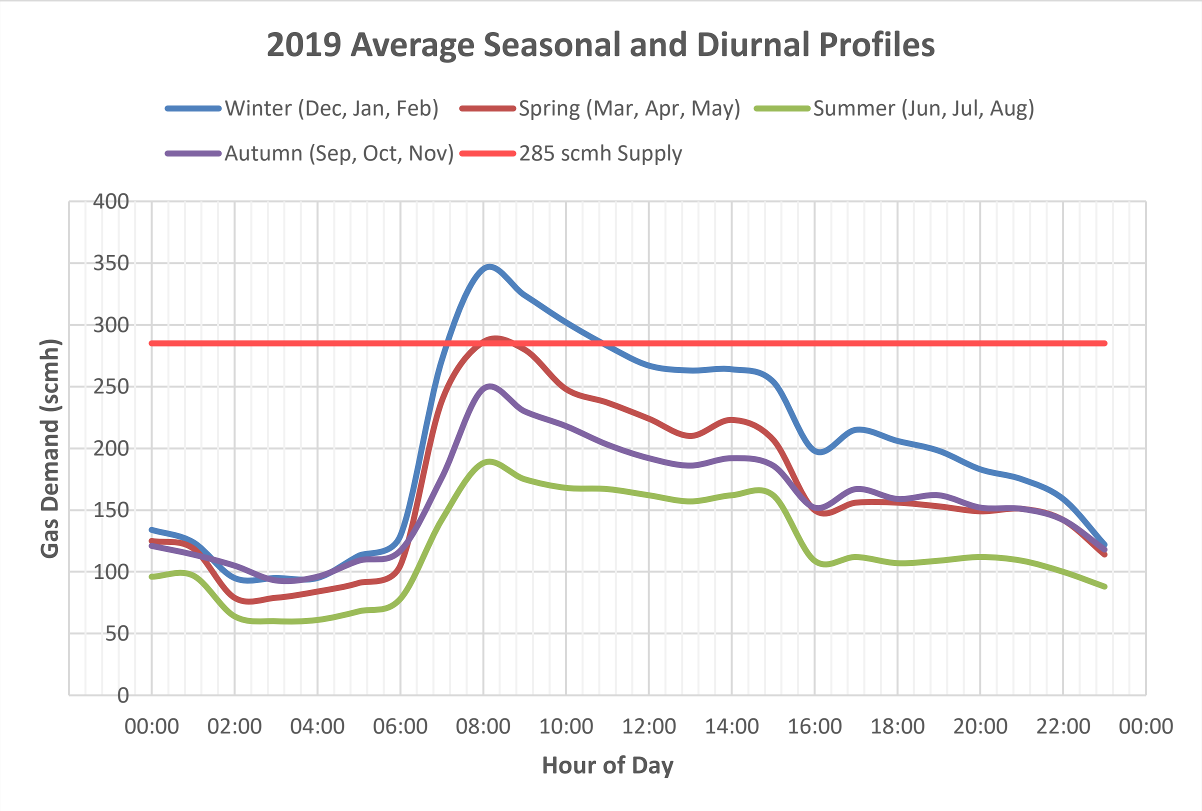


Figure 1: Knockroe seasonal and daily diurnal profile

2.2 Glebe West AGI

A larger biomethane production injects into a larger network for the second project of study. The AD site is proposed to produce 500 scmh of biomethane at 4 bar for grid injection. Indicative summer and winter flow possible are 845 and 14,863 scmh.

Approximately 0.6 km of DX pipeline would be required to connect to the nearest suitable DX connection and 31 km of TX pipeline to connect to the nearest TX connection point.

The 2019 seasonal and diurnal gas demand profile for Glebe West is shown below. Since a much larger demand is seen in this network, fluctuations and trends are smoother in this profile. The network shows a high winter demand and low summer demand. The demand and capacity in this network are significantly larger than the AD size so any constraint on the 4-bar network is expected to be minimal.

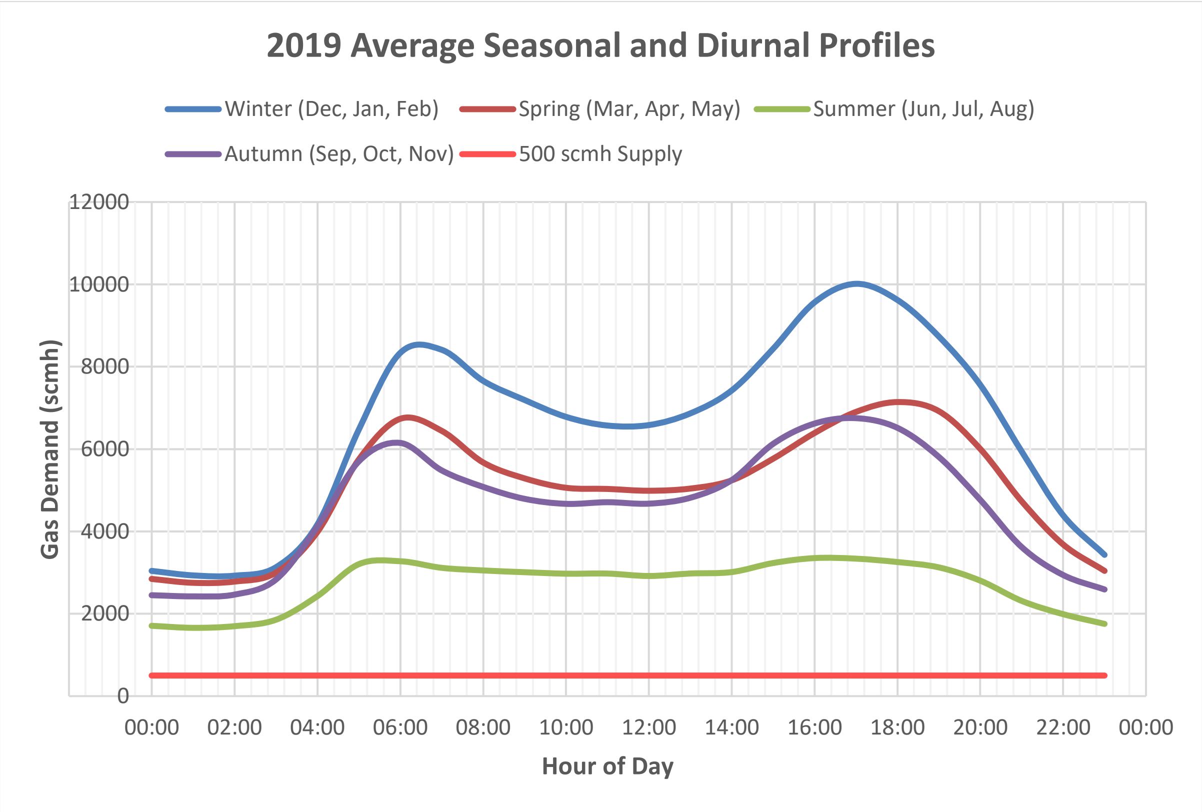


Figure 2: Glebe West seasonal and daily diurnal profile

3 Biomethane connection types – Ownership Models

For each project ready to connect into the GNI gas network the feasibility study has considered six schemes. These are:

- Scheme 1 – 4 barg grid connection
- Scheme 2 – 70 barg grid connection
- Scheme 3 – Virtual pipeline
- Scheme 4 – Within grid compression
- Scheme 5 – Virtual pipeline with a GNI ownership model
- Scheme 6 – Within grid compression with a GNI ownership model

Schemes 1 to 4 have different methods of operation. Scheme 5 operates in the same manner as scheme 3 but has a different pricing method. Similarly, scheme 6 operates in the same manner as scheme 4 with a different pricing method which is detailed in the subsection below.

3.1 Scheme 1 – 4 barg grid connection

Scheme 1 is a typical biomethane connection into a local lower pressure tier gas distribution network which operates as shown in the diagram below.

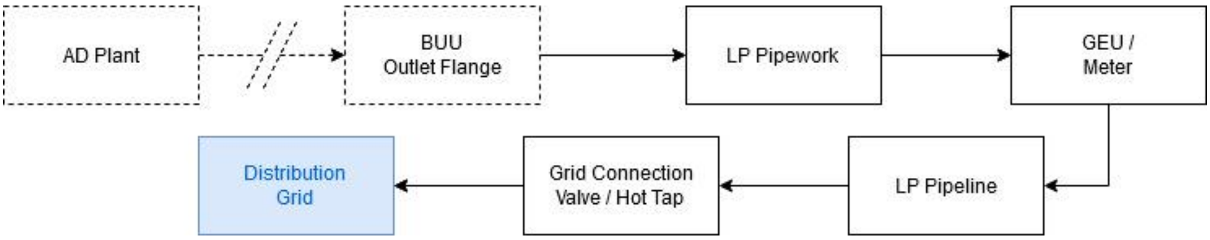


Figure 3: 4 barg connection

<u>Basic Operational Process</u>

1. Cleaned and quality measured biogas from the AD site is fed out of the BUU (This process is the same for all schemes & not considered in the financial model)
2. Gas is fed through the GEU (which meters the gas) situated on the same site, outputting gas in spec with the distribution grid.
3. A LP pipeline connects gas from the AD site to the proposed connection point.
4. Gas is then injected into the grid at the connection provided there is capacity in the distribution grid.

3.2 Scheme 2 – 70 barg grid connection

Scheme 2 operates as scheme 1 but the site connects into a nearby high-pressure transmission pipeline. Sites will need on-site compression to achieve network pressure as shown and detailed below in Figure 7. In GB there is one NTS Injection Project (75 bar) and around 20 into LTS (19 – 70 bar).

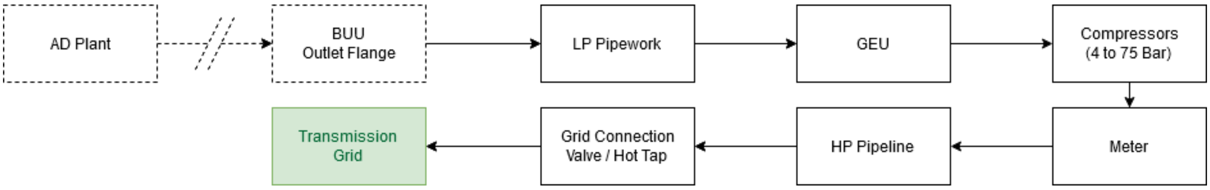


Figure 4: 70barg connection

<u>Basic Operational Process</u>

1. Cleaned and quality measured biogas from the AD site is fed out of the BUU (This process is the same for all schemes & not considered in the financial model)
2. Gas is fed through the GEU (which meters the gas for TX) situated on the same site, outputting gas in spec with the transmission grid.
3. Gas is then chilled and compressed at the AD site inline with the transmission grid at the compressor installation (typically 2 compressors)
4. For 75 bar TX, the gas is metered after the compressors.
5. Metered gas is fed through a HP pipeline from the AD site to the transmission grid connection point.
6. The connection into the grid requires an operable valve connection, a hot tap is ideally avoided.

3.3 Scheme 3 – Virtual pipeline

For scheme 3 the produced biomethane is processed on site and then compressed to 250 bar for transport via CBM trailer. This is shown in figure 8 below. This model includes costs for high pressure compression, purchasing CBM trailers and the cost of the decanting station.

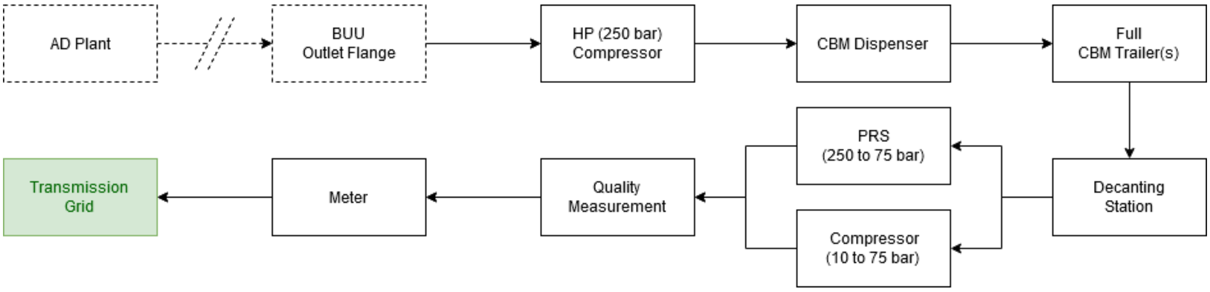


Figure 5: Virtual pipeline

<u>Basic Operational Process</u>

1. Cleaned and quality measured biogas from the AD site is fed out of the BUU (This process is the same for all schemes and not considered in the financial model)
2. Biomethane gas quality is measured to ensure it is within specification.
3. Biomethane is compressed up to 275 barg using a CBM Compressor dispensed into CBM trailers.
4. The trailers transport the gas to a decanting site.
5. At the decanting station, CBM is decanted from the trailer at an offloading cabinet and then through a PRS.
6. Gas is then measured and metered prior to injecting into a 19-bar transmission grid via an existing valve or a new connection point.
7. Odorant is required at all injection points in Ireland and propane may be required.
8. When the trailer pressure reaches the TX pressure, a hydraulic compressor can take over to exhaust the trailer down to 30 barg. This is not necessarily done as it can be more expensive to do this than leave some residual gas in the trailer.

3.4 Scheme 4 – Within grid compression

Scheme 4 is as scheme 1 however there is the additional process of compression which is performed at the local AGI to compress gas into higher pressure tiered network when required (in summer when there is insufficient capacity for the biomethane).

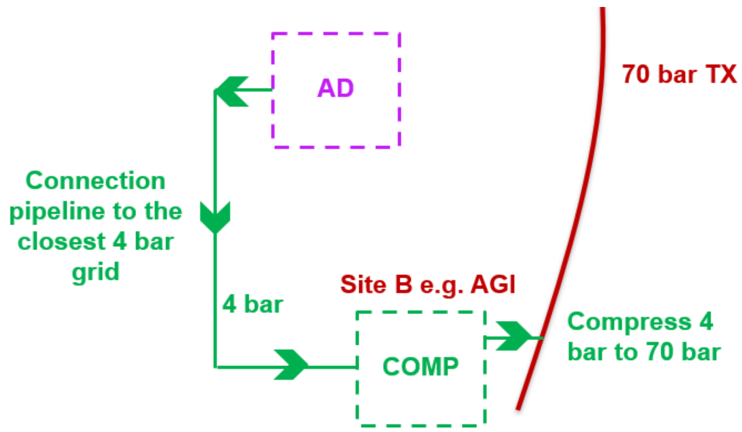


Figure 6: Within grid compression

Basic Operational Process

1. Operates as per Scheme 1, with Biomethane injected into local 4 bar grid.
2. At an appropriate point (could be an AGI), gas is compressed from the 4 bar grid into the 70 bar grid
3. This compression occurs within the GNI grid. No gas quality monitoring at this point as the gas is already within the grid.
4. Gas flow can be metered to provide useful information for the Grid Operator.

3.5 Scheme 5 – Virtual pipeline with a GNI ownership model

Scheme 5 operates in the same manner as scheme 3. However, the CAPEX and O&M costs of haulage, dispensing and injection into the network is priced as a service GNI sells to a biomethane developer. Some of the heavy upfront cost of a project is alleviated and paid back over time through the charge.

The tariff assumed as part of this study is €0.008 / kWh biomethane.

3.6 Scheme 6 – Within grid compression with a GNI ownership model

Scheme 6 operates just as scheme 4 but the CAPEX and O&M costs of the AGI compressor are borne by GNI. Within Grid compression is sold to the biomethane developer as a service. The tariff set in the financial model is calculated through iteration based on a set payback period of 10 years.

The tariff calculated for Knockroe is €0.0097 / kWh biomethane.
The tariff calculated for Glebe West is €0.0057 / kWh biomethane.

4 Design Concept

4.1 Within Grid Compression Design Principle

Within Grid Compression has been studied briefly by the gas networks in GB. During warm summer nights gas demand can fall close to zero. A biomethane site will ideally inject gas at the same rate throughout the year so encounters capacity issues during the summer and will be unable to export gas.

The same capacity constraint applies if there is a large industrial gas consumer on the same network as the biomethane project. When the factory takes gas, there is capacity. At weekends/bank holidays/summer shutdowns there is no capacity.

The operating principle underpinning Within Grid Compression is that during the summer the gas network will be able to reduce the regulator set points at the AGIs that feed the localised network a biomethane site is connected to. This will give a compressor a pressure band to operate in and ensure that the compressor is not moving gas from low pressure to high pressure networks for the regulators on an AGI to then flow the gas back from high to low pressure. For example, the distribution networks in Ireland are at a nominal 4 bar networks and as such the maximum operating pressure that the AGI regulators will be set at is 3.9 bar. If this is reduced to 3.5 bar during times of low network capacity (i.e. summer) it will give the compressor a band to operate in from 3.5 bar to 3.9 bar. The pressure cannot rise above 3.9 bar as the compressor will be switched on to move gas out of the network. If the pressure falls and approaches 3.5 bar then compressor will turn off. If the network pressure falls even further below 3.5 bar then the AGI regulators will start to open and move gas from the high pressure network to low pressure. Maintaining 3.5 bar for summer demand will be acceptable in terms of gas security of supply.

A model of compressors sizes has been produced by CSL. GNI provided historical demand data on the 4 bar network for both Knockroe and Glebe West AGIs, as well as information on the pipelines that makes up these networks. From this it was possible to calculate a linepack volume of the network and if high and low set points can be provided it gives high and low bounds of volume for the compressor to operate in. For example, from the information given by GNI the local 4 bar network for Knockroe was calculated to have internal volume of approx 796 m^3. If the AGI regulator set points can be lowered to 3.5 bar then the compressor can operate between 3.9 and 3.5 bar. This equates to network gas volumes of 3901 Sm^3 and 3583 Sm^3.

Using the historical demand data for the last three years provided by GNI, CSL then developed an Excel model whereby adding in a flowrate from a new biomethane site allowed us to see when the gas network would be full, i.e. above the corresponding max volume value (3901 Sm^3 for Knockroe). The compressor would then turn on to reduce the gas within the network to the lower volume limit. We could then calculate the number of compressor operating hours per year that on average that network would need to support the biomethane injection site. The model allows different capacity compressors and will review the effect on running hours, i.e. higher flow-rate compressor needs less running hours, to deduce an optimal compressor size.

Assessing the data provided by GNI allowed the choice of appropriately sized compressors for the networks and proposed biomethane connections, also assessing the Capex and Opex costs of different sixed compressors so that the optimal compressor can be identified. The design philosophy for each site takes into account running hours, standby capability, expansion and turndown ratio. For example, 2 x 50% is a good way to start if load factor is high but there are times with only limited compression requirement. Turndown can be replaced by on/off operation when flows are low. If the required runtime is low enough, a one compressor configuration can be more efficient due to lots of downtime to undergo maintenance. This does have its drawbacks such as having no backup for an unexpected mechanical breakdown and limits potential expansion.

4.2 Compressor Control

Pressure in the DX pipe will rise when there is insufficient gas demand on the DX network to utilise all the gas being produced by the Biomethane plant. The compressor once appropriately sized should be consistent with the experienced extent of export constraint and must have variable set points configurable for suction pressure, discharge pressure and flow. There are two main options for controlling the compressors:

- Ideally, the compressor should operate on a variable flow basis depending on the difference between the network demand and the biomethane injection rate. However, such a system cannot be introduced unless real time information is made available on gas demands at customer supply points and this would be very expensive to achieve.

- The next possibility is that the compressor will be set up to activate automatically when grid pressure increases above a chosen level, controlled by a PLC. The compressor will continue to run at the given set points but will shut down at the low network pressure point. This minimum pressure will be set so that there will always be sufficient pressure in the network to maintain supplies at the network extremity points. The low- and high-pressure points set for both networks is 3.5 and 3.9 barg. The compressor will therefore operate at the given set points on an on/off basis when there is insufficient demand from customers connected to the network to utilize the gas being produced by the Biomethane plant.

4.3 Compressor Security of Supply

To ensure security of gas supply the Compressor module is designed so that:

- The pipeline pressure system cannot be drawn down below a safe minimum pressure to supply customers on the extremity of the network.
- The pipeline into which the compressor will discharge cannot be pressurized above its safe operating limit.

The mechanical/control components utilised to achieve these objectives included: -

- Low pressure switch installed in the suction side of the compressor.
- Low-Low pressure mechanical slam shut valve installed in the suction side of the compressor.
- High pressure switch installed in the discharge side of the compressor.
- High-High pressure mechanical slam shut valve installed in the discharge side of the compressor.

These components may be within the compressor supply package or installed separately in a module.

The main components are illustrated in the following diagram:

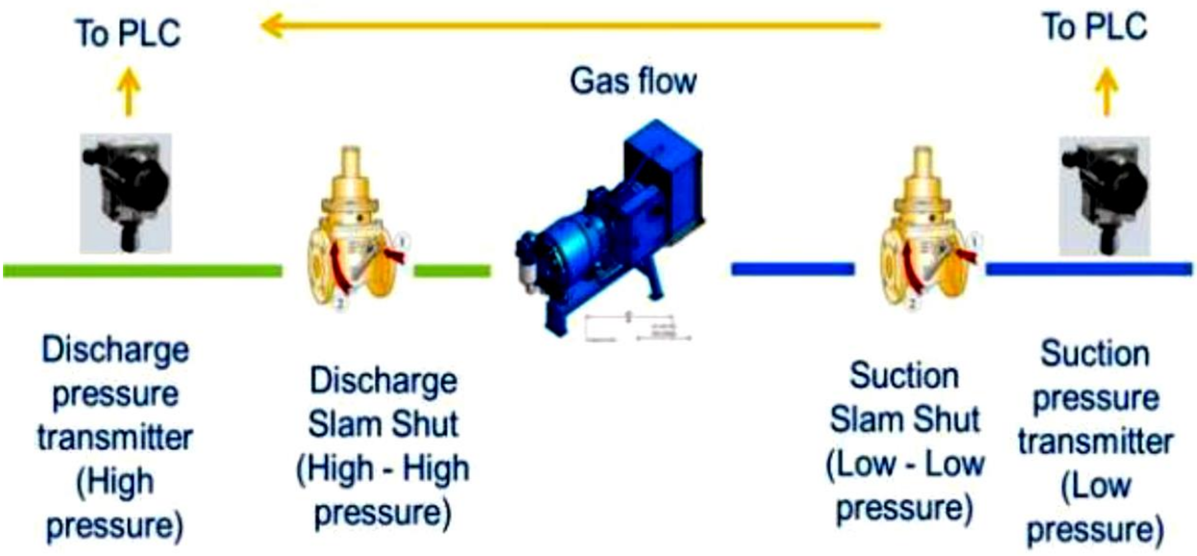


Figure 7: Compressor module security of supply components

4.4 Circular Flow

To prevent circular flow, it is necessary for the compressor control system to interact with any PRS injecting into its 4-bar line. This is to prevent the PRS from supplying gas whilst the compressor is running. Control is achieved by installing a solenoid and safety bypass regulator in the pressure reduction unit auxiliary system so that the PRS stops feeding gas when the compressor is activated. When the compressor stops the solenoid valve opens allowing the PRS to sense downstream pressure and operate normally. If the solenoid valve fails to open then the safety bypass valve will open as the pressure falls to a pre-determined safe minimum.

4.5 PLC Control

The whole system is controlled by a PLC to ensure supply and demand in the network is maintained in balance whilst also ensuring safety and security of supply.

The PLC performs the following control functions:

- Compressor starts on high set point pressure
- Compressor stops on low set point pressure
- Compressor stops on high filter differential pressure
- Compressor stops on high outlet temperature
- Compressor stops on Low – Low pressure – indicates Slam Shut closed
- Compressor stops on High – High pressure – indicates Slam Shut closed
- Regulator solenoid valve closes and opens on Compressor start and stop – indicates closed or open

- Compressor stops on low system extremity pressure

The system can be monitored form the PLC display which shows the status of:-

- Compressor running
- Faults
- Pressures
- Slam shut valves
- Solenoid valves
- Filter DP alarm

A snap shot of a PLC overview display is shown as follows: -

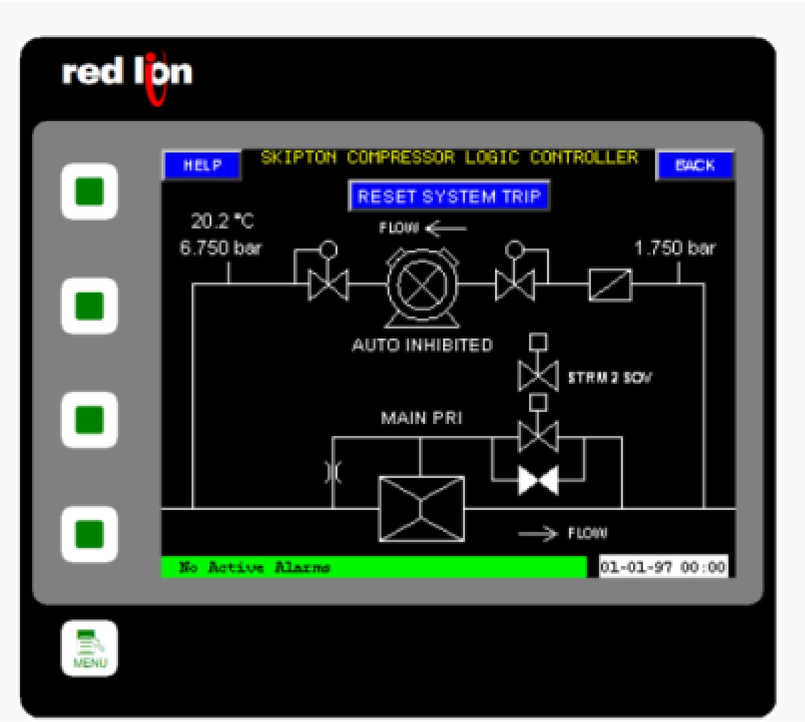


Figure 8: PLC mimic display

5 Compressor Options

5.1 Compressor Types

For such an application, two types of compressors are considered: reciprocating and screw. In both cases, it is quite important to begin with the boundary limits of the application, especially the capacity required, inlet conditions of the gas (composition, pressure, temperature) and discharge pressure, as these are the determining factors which define the range of compressor products available in the market which can be considered for the application. Even with a single manufacturer, differences in capacity or pressure can change the design which the manufacturer has available to satisfy the requirements of the application. This also means that changes in the application design parameters may have fundamental impact on the available features of the compressor or the system.

Vane compressors are widely used for gathering raw digester gas and feeding it to the process plant. However, while vane compressors are simple, robust and tolerant of the dirty digester gas, they are not available with design pressures high enough for grid entry. They also have application limitations on pressure ratio. As such, they are not considered here.

5.2 Reciprocating Compressors

Reciprocating compressors (recips) are widely used in natural gas and process gas applications and are available in a wide variety of configurations. Traditional designs, available for decades, have been produced for oil and gas applications, with the most conservative designs used in refineries and chemical plants which are designed for a useful life of at least 20 years. The growth of certain new applications during the past 20 years (e.g. CNG vehicle fuelling) have created a new range of medium and high pressure compressors specifically designed for the needs of these processes. In general, these newer designs are somewhat less robust than their predecessors but are also more inventive in their application of design principles, and usually much more economical from the perspective of first cost.

The gas which is compressed by the reciprocating motion of the piston riding in its cylinder is sealed by non-metallic elements specially designed to withstand the extremes of stress, temperature and friction. These elements run more reliably when lubricated by moderate amounts of oil which are injected in various places. This oil also helps to seal the gas from leaking (internally and externally), so some oil will be found in the gas discharged from the compressor.

Advances in non-metallic sealing elements, as well as requirements of some applications have led to the development of recips which do not use oil to lubricate the non-metallic sealing elements.

5.3 Screw Compressors

Screw compressors (screws) are used for a wide variety of industrial air compression applications where compressed air is considered a power source for tools and other devices. For these markets, screws have become the standard and suitable systems are produced in large numbers. For gas compression, their application is highly attractive, but less common than recips, as special design features must be considered. Dynamic shaft sealing must be much more robust and internal rolling element bearings must either be isolated from the compressed gas, or else must tolerate the gas/oil mixture as its lubricant. However, once these elements are designed in, the result is often a very flexible, robust, small device which can competitively compress gas. As they use rotary elements with little friction or other wearing parts, wear characteristics are very attractive in comparison to recips. Heat of compression is absorbed by the circulating oil, so high compression ratios are possible. It is for these reasons that wherever screw compressors can be used (considering their design limits) they are almost always attractive alternatives and often chosen over recips.

As with recips, screw compressors can be produced in oil lubricated (oil-flooded) designs or oil free to suit specific applications. Oil-flooded designs are generally simpler, more reliable, more efficient and cheaper. Such designs are commonly used in refrigeration applications, so casing pressures up to 20-25 barg are readily available. Each system will necessarily have a gas/oil separator, finished with a coalescing filter to assure that oil consumed and taken downstream from with the discharge gas is minimised.

Oil free screws have further design features to keep the gas isolated from the bearings and to maintain clearances between the mating rotors, and so are more costly. As with recips, oil free screws have limitations on compression ratio to keep gas temperatures low. Again, unless the process absolutely requires oil free, oil-flooded screws are preferred.

6 Compressor Selection

Compressor selection was determined based on the biomethane production and for within grid compression, the number of hours the compressors will need to run for. For the purpose of this study compressor sizes were limited to 1500 scmh as the requirements for both projects did not need to exceed this. A suitable range for compressor size was calculated and then chosen from existing CNG Services compressor quotations.

As part of this study GNI provided 3 years of network data for Glebe West and Knockroe and included hourly local gas demand and network volumes. Using this data and applying the biomethane injection for both projects the compressor size needed and run time was calculated. The data was used to see if capacity is required though the high and low pressure point volumes and would then switch the compressor on or off. The data was also used to calculate how much of the gas is constrained to the 4-bar network. These calculations can be found in separate spreadsheets attached.

6.1 Knockroe Compressor Selection

The compressor type chosen for this project is a reciprocating compressor. The compressor functional specifications for Knockroe are shown in the table below.

Table 2: Compressor properties for Knockroe

Scheme	**Scheme 2 70 barg Grid**	**Scheme 3 Virtual Pipeline**	**Scheme 4 WG Compression**
# Compressors	2.00	2.00	2
Compressor Size	300.00	300.00	600.00
Run Hours	8113.95	8113.95	1808.00

Description				**Units**
Suction Pressure	10.0	10.0	5	bar a
Suction Temp.	25.0	25.0	15.0	C
Relative Humidity	0.00	0.00	0.00	%
sat vap P H20 at Ts	31.67	31.67	17.05	mbar
partial P H20 at Ts	0.00	0.00	0.00	mbar
Water flow ratio	0.00	0.00	0.00	mol H20/mol dry gas
Dry Molar Flowrate	270.2	270.2	600.00	Nm3/h
Total wet flow	270.2	270.2	600.0	Nm3/h
	0.003	0.003	0.007	kgmol/s
Suction Volume	0.5	0.5	2.1	m3/min
Suction Volume	29.9	29.9	128.2	Am3/h
Suction Volume	8.3	8.3	35.6	l/s
Discharge Pressure	71.0	251.0	71.0	bar a
Isothermal power	16	27	47	kW
Iso efficiency	50%	50%	50%	%
Shaft Power	32.52	53.47	94.48	kW
Motor efficiency	93.12	93.12	93.12	%
Terminal Power	**34.92**	**57.42**	**101.47**	kW
CW Temp rise	10.00	10.00	10.00	C
CW flow	2.80	4.60	8.13	m3/h
Total Power / Annum	**283.36**	**465.92**	**183.45**	MWh

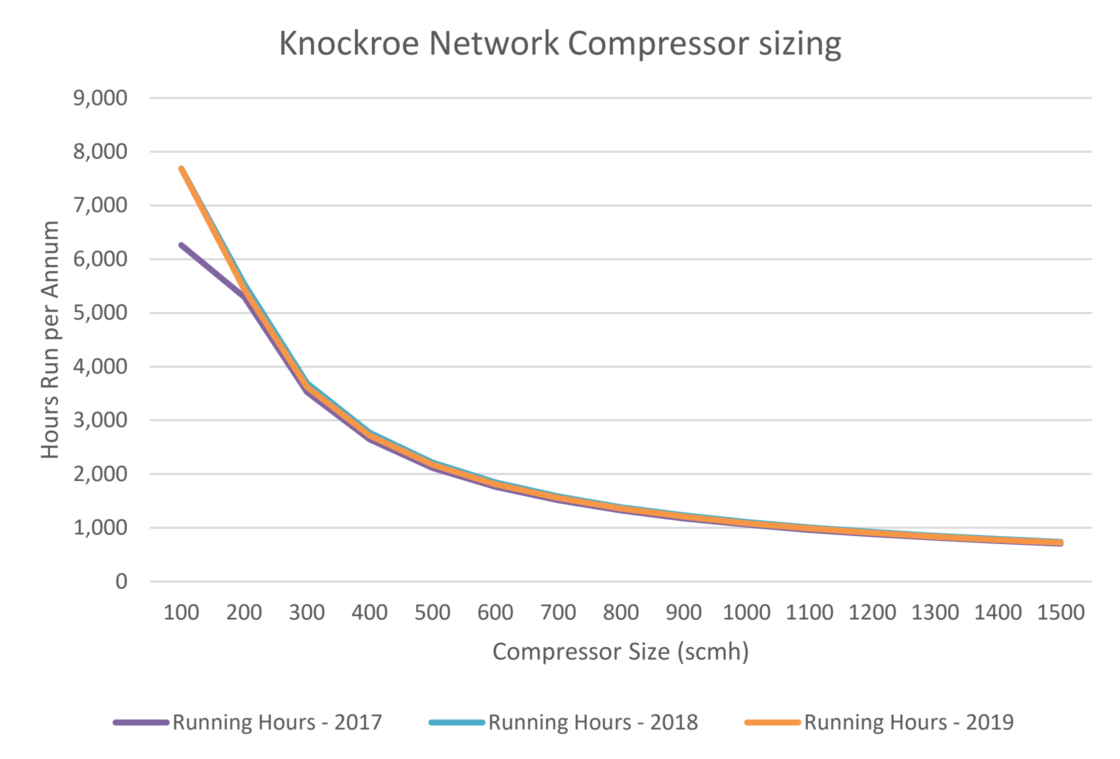


Figure 9: Knockroe compressor sizing

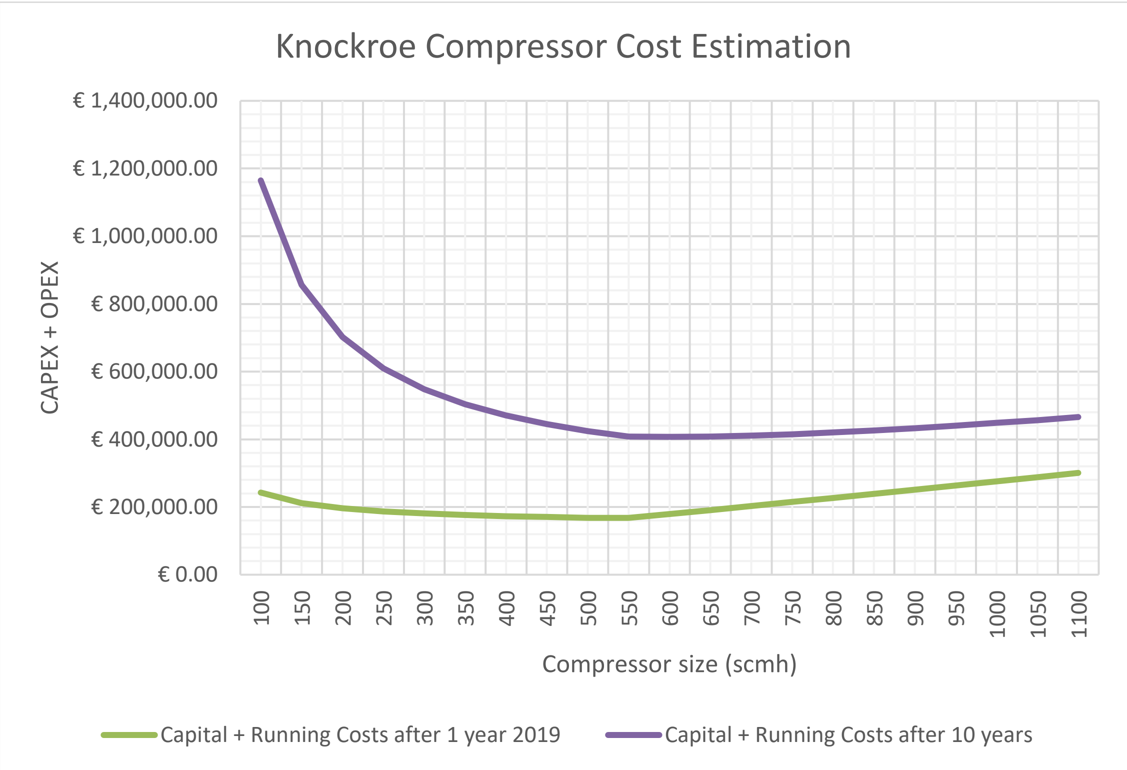


Figure 10:Knockroe compressor cost estimation

Compressor data gathered using the GNI network data are as shown in the graphs. The trends shown from compressor sizing are as expected. An exponential decrease in compressor run hours is seen with an increase in compressor size. This means smaller compressors start to lose in functionality and at a certain point, larger compressor sizes do little to reduce the running hours. The CAPEX for compressors increases as they increase in size however the OPEX of running them reduce as less time is needed to function. The results show the combined CAPEX and OPEX cost reduce to an optimal band then start to increase. Using the compressor sizing data as shown in the graphs an appropriate a compressor size of 600 scmh was chosen and cross referenced with existing CNG Services quotations.

The table below shows the Knockroe network volume and the quantity of gas that is constrained by the network. The compressors need to run an average of 5 hours a day.

Table 3: Knockroe network constraints

Total Network volume [Sm3]	**796**			
High pressure point [barg]	**3.9**			
Low pressure point [barg]	**3.5**			
Pressure High Point Volume [m3]	**3,901**			
Pressure Low Point Volume [m3]	**3,583**			
	Demand	**Production**	Amount Constrained	Gas Injected
Average Constraint 2017	**822,372**	**1,881,000**	**56%**	**44%**
Average Constraint 2018	**1,388,373**	**2,496,315**	**44%**	**56%**
Average Constraint 2019	**1,409,041**	**2,496,600**	**44%**	**56%**
Average Constraint 2019	**3,619,786**	**6,873,915**	**47%**	**53%**

Investigations show the AGI for Knockroe has space for the selected compressor arrangement onsite. The suggested arrangement is shown on drawing 750-01-401 in the appendix. The connection points shown are preliminary and the actual connection points requires detailed design.

6.2 Glebe West Compressor Selection

The compressor type chosen for this project is a reciprocating compressor. The compressor functional specifications for Glebe West are shown in the table below.

Table 4: Glebe West compressor properties

Scheme	Scheme 2 70 barg Grid	Scheme 3 Virtual Pipeline	Scheme 4 WG Compression
# Compressors	2	2	2
Compressor Size	500	500	700
Run Hours	8113.95	8113.95	305.00

Description				Units
Suction Pressure	10.0	10.0	5	bar a
Suction Temp.	25.0	25.0	15.0	C
Relative Humidity	0.00	0.00	0.00	%
sat vap P H20 at Ts	31.67	31.67	17.05	mbar
partial P H20 at Ts	0.00	0.00	0.00	mbar
Water flow ratio	0.00	0.00	0.00	mol H20/mol dry gas
Dry Molar Flowrate	474.2	474.2	700.00	Nm3/h
Total wet flow	474.2	474.2	700.0	Nm3/h
	0.006	0.006	0.009	kgmol/s
Suction Volume	0.9	0.9	2.5	m3/min
Suction Volume	52.4	52.4	149.6	Am3/h
Suction Volume	14.6	14.6	41.6	l/s
Discharge Pressure	71.0	251.0	71.0	bar a
Isothermal power	29	47	55	kW
Iso efficiency	50%	50%	50%	%
Shaft Power	57.08	93.86	110.23	kW
Motor efficiency	93.12	93.12	93.12	%
Terminal Power	**61.30**	**100.79**	**118.38**	kW
CW Temp rise	10.00	10.00	10.00	C
CW flow	4.91	8.07	9.48	m3/h
Total Power / Annum	**497.39**	**817.83**	**36.10**	MWh

Compressor data gathered using the GNI network data are shown in the graphs below. The trends shown from compressor sizing are as expected. The same trend observed for Knockroe is also observed for Glebe West where there is an optimal compressor size. Using the compressor sizing data shown in the graphs a compressor size of 700 scmh was selected and cross referenced with existing CNG Services quotations. A slightly smaller compressor size could have been chosen but the difference in real life quotations was minimal. This also allows expansion of the within grid compression as there are nearby potential schemes of up to 2000 scmh.

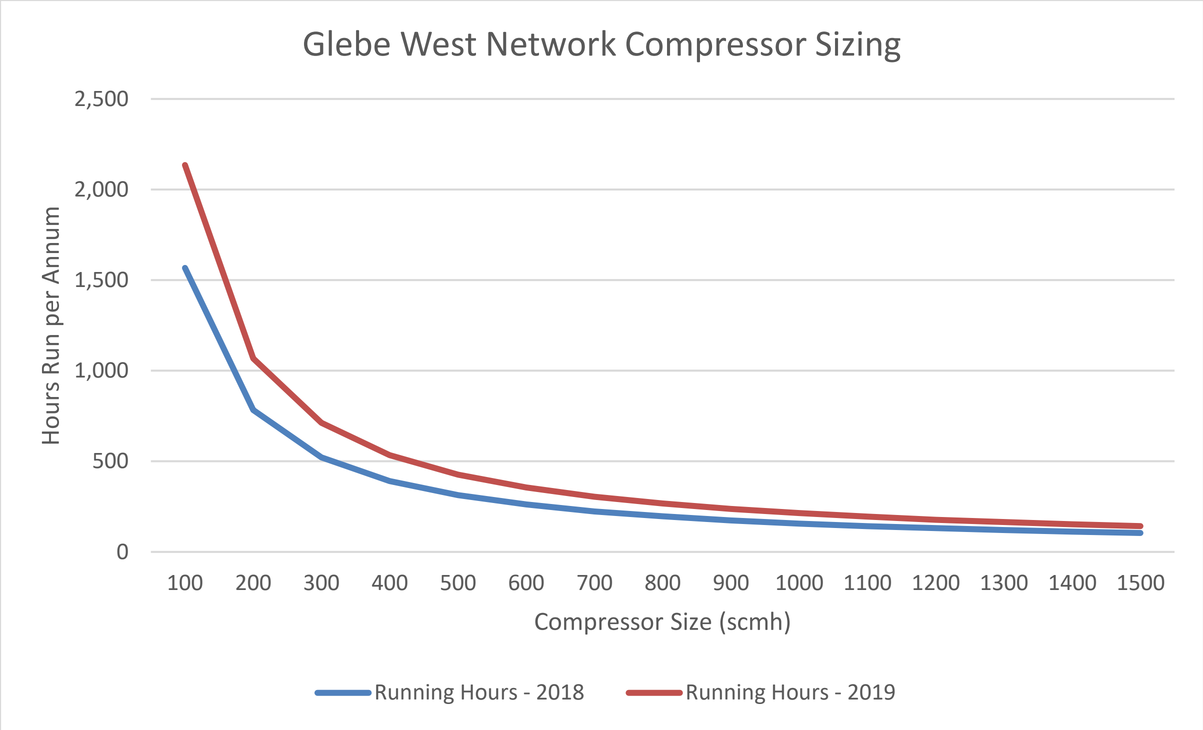


Figure 11: Glebe West compressor sizing

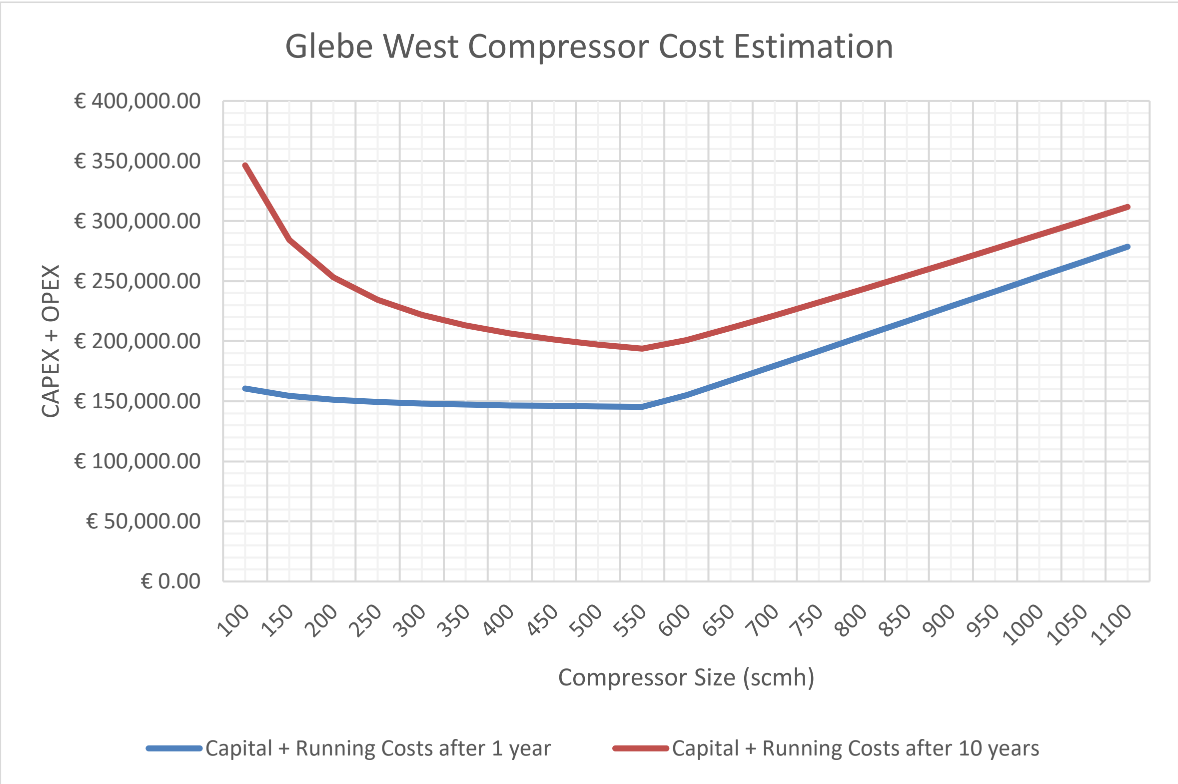


Figure 12: Glebe West compressor cost estimation

The table below shows the Knockroe network volume and the quantity of gas that is constrained by the network. The compressors need to run an average of 1 hour a day.

Table 5: Glebe West network constraints

Total Network volume [Sm3]	**800**			
High pressure point [barg]	**3.9**			
Low pressure point [barg]	**3.5**			
Pressure High Point Volume [m3]	**3,920**			
Pressure Low Point Volume [m3]	**3,600**			
	Demand	**Production**	**Amount Constrained**	**Gas Injected**
Average Constraint 2017	**0**	**3,300,000**	**0%**	**100%**
Average Constraint 2018	**161,592**	**17,520,000**	**1%**	**99%**
Average Constraint 2019	**219,034**	**17,520,000**	**1%**	**99%**
Average Constraint 2019	**380,626**	**38,340,000**	**99%**	**1%**

Compressor Run Hours 2017	**0**
Compressor Run Hours 2018	**224**
Compressor Run Hours 2019	**305**
Compressor Run Hours Average	**176**

Investigations show the AGI for Glebe West requires more space for the onsite compressor arrangement. The suggested arrangement is shown on drawing 750-01-403 in the appendix. The connection points shown are preliminary and the actual connection points require detailed design.

7 Maintenance and Operational Requirements

The compressor module and associated safety equipment will be installed in its own secure enclose. It is anticipated that the Compressor will be maintained by the manufacturer's nominated servicing agent. For the projects being considered a reciprocating compressor would be best and will require maintenance time. Weekly inspections are required for gas and oil leaks during the running season and lubricating oil needs to be topped up. Due to the nature of within grid compression the duty cycle is expected to be low and the maintenance will be considerably less than if it was continuously running. Reciprocating compressors can require downtimes of weeks to repair or replace seals, valves, bearings, and pistons but as the duty cycle can be spread over a number of years maintenance will be considerably less.

Maintenance of the mechanical parts, maintenance of the compressor monitoring, and safety devices installed within the compressor enclosure will need to be carried out either to be undertaken by GNI employees or a third-party subcontractor.

In addition to the maintenance specific to the compressors, there will be an additional maintenance requirement on items added to the site to enable compression to take place. This will include statutory safety requirements and include:

- Pressurized systems inspections and validation
- Filter checks and replacement
- Safety protection system testing
- Instrument calibration and testing
- Valve maintenance and testing
- Electrical system maintenance and testing

8 Financial Model

To carry out this study a comprehensive spreadsheet model was built on excel. The spreadsheet takes key inputs and variables of a biomethane project to produce a financial summary with comparison of the 6 schemes being considered. As there are 2 projects for study Knockroe and Glebe West, there are 3 models. A generic model and 2 tailored models Knockroe and Glebe West. The generic model has been written so it can be tailored to any future or existing projects and the tailored models allow for changing of key variables for additional study. As the model is complicated the spreadsheet has been split into 12 sheets with only a single sheet used for user input. The table below gives a description of each sheet.

Table 6: Financial Model Description

Sheet	Description	Comments
1	Summary	Provides description for each sheet and scheme.
2	Input Variables	Interface for all user input and variables.
3	Results	Quick basic summary of each scheme.
4	Financials	Detailed summary of each scheme
5	CAPEX	Project installation and construction costs.
6	OPEX	Electrical & heating, maintenance and OPEX costs.
7	Biomethane & Gas Flows	Biomethane Income and fossil gas import.
8	Propane Flow	Propane calculations to reach target grid CV.
9	Haulage	Trailer haulage calculations and OPEX
10	Compressors	Compressor calculations
11	Compression Fee	Calculates the pass-through charge if GNI owned the Within Grid Compressor Station.
12	CO2 Emissions	Calculates CO2 emissions for each scheme

8.1 Model Inputs

Fixed inputs and calculations in the model are placed into separate sheets, 5 to 11. These sheets along with the input variables feed into sheet 4 Financials to provide output for study. The input variables used in the model as shown in the table below are as follows:

- Biogas flowrate input
- Scaling of AD CAPEX – allows scaling to model different AD sizes.
- Compression inputs – gives choice of generic or actual compression costs.
- Compression fee calculator – compression fee calculation with macro for the GNI charge of within grid compression service.
- GNI ownership passthrough charges – the tariff GNI charge customers to collect, transport and inject gas or operate and maintain the within grid compressor for schemes 5 and 6. The compression fee calculator macro sets the within grid compression tariff. The macro calculation is done on sheet 11 Compression fee based on the chosen payback period and WACC.
- Connection costs – Pipeline costs and distances.
- GNI connection Policy - If selected then GNI owned assets associated with connection to the network are scaled by the stated scaling factor.
- Energy prices – Sourced from SEAI.
- Capacity Issues - How much biomethane cannot get into the network as a result of local capacity issues. Zero for all schemes other than scheme 1 where distribution capacity is restricted due to local area constraints.
- Within grid compressor size and runtime
- Propane addition and target CV
- Haulage parameters including trailer type, quantity and average round trip.
- Emissions variables – CO_2 calculation parameters

Table 7: Input parameters

Parameter	Value	
Biogas Production & Costs		
Biogas Flowrate		
Biogas Production Per Hour	470	Nm3/hr
Biomethane Injection Per Hour	*285*	Sm3/hr
Biomethane Injection Per Annum	*24*	GWh
Scaling of AD CAPEX		
Default AD Plant Size	40	GWh
Production Plant Scaling Factor	25%	%
Feedstock and Operational Scaling Factor	50%	%
Compression Inputs		
Use Actual Compressor Costs?	Yes	
Generic Compression Scaling Costs		
Compressor Scaling Factor	250.00	€/scmh
Compressor Minimum Cost	140,000	€
Actual Compressor Costs		
Scheme 2 - Tranmsision Compression Costs	280,000	€
Scheme 3/5 - Virtual Pipeline Compression Costs	140,000	€
Schemes 4/6 - Within Grid Compression Costs	280,000	€
Compression Fee Calculator		
WACC	8%	%
Payback Period	Year 10	
Goal Seek	Find Compression Fee	
GNI Ownership Pass Through Charges		
GNI Charge for Virtual Pipeline Service	0.80	c/kWh
GNI Charge for Within Grid Compression Service	0.97	c/kWh
Connection Costs		
Biogas Production Site Pipeline Length		
Scheme 1 - Distribution Connection	0.41	km
Scheme 2 - Transmission Connection	9.60	km
Scheme 4/6 - Distribution Connection Within Grid	0.41	km
Pipeline Costs		
Pipeline cost per km - IP	320,000	€/km
Pipeline cost per km - HP	1,100,000	€/km
GNI Connection Policy		
Applicable to connections	Yes	
Applicable to Within Grid Compression Station (GNI Owned)	No	
Connection Policy Scaling Factor	30%	
Energy Prices		
Gas Costs		
Gas basic cost	3.55	c/kWh
Propane import cost	65.10	c/litre
Electricity Costs		
Electricity cost, import	11.20	c/kWh
Electricity value export	5.00	c/kWh
Gas Sale Price & Subsidy		
Gas basic sales value	1.96	c/kWh
Subsidy Price	7.00	c/kWh
Capacity Issues		
Distribution Capacity Possible (Production less constraint %)	53%	%
Within Grid Compressor Size	600.0	Sm3/hr
Withing Grid Compressor Run Hours	1808.0	hr / annum
Propane		
Include Propane	Yes	
Target CV for gas grid	37.4	MJ/m3
Haulage Parameters - Relevant to Scheme 3 Only		
Average Round Trip between Mother and Daugher Station	12.00	miles
Trailer Type	UMOE	
Number of Trailers	3	
Emissions Variables		
CO2 Calculation Parameters		
Carbon Intensity of Ireland Electricity Grid	331.40	gCO2e/kWh
Carbon Intensity of Ireland Gas Grid	204.70	gCO2e/kWh
Diesel Calorific Value	36.61	MJ/L
Diesel Well to Tank	73.31	gCO2eq/MJ diese
Diesel CO2 Combustion Emissions	2680.00	gCO2/l
Propane Emission Factor	229.30	gCO2/kWh

8.2 Biomethane Flows & Income

Sheet 7 in the model does the analysis of taking biogas production from AD to produce the revenue from production and export of biomethane. The analysis includes:

- Biogas flow from AD
- Biomethane produced post upgrading
- AD plant availability
- Propane injection - Propane calculations based on target CV is done on separate sheet 8. Propane flow and then feeds into this sheet.
- Capacity constraint – The DX network for Knockroe and Glebe West have a capacity less constraint of 47% and 3% respectively
- Value of biomethane export

Table 8: Biomethane flows

Scheme	Glebe West 4 barg grid	Knockroe 4 barg grid
Description		
Analysis of energy flow to gas grid		
Biogas flow from AD	825	470
Biogas flow to BUU	870	496
Methane % in the biogas	55%	55%
Methane Higher Heating Value	37.74	37.74
Biomethane Purity Post Upgrading	97%	97%
Biomethane Produced (Hourly)		
Biomethane Flow (Sm3/hr)	493.51	281.15
Biomethane Flow (Nm3/hr)	467.78	266.49
Biomethane energy value (MJ/Sm3)	36.61	36.61
Biomethane energy value (MJ/h)	18066.37	10292.36
Biomethane energy value (MWh/h)	5.02	2.86
Plant Availability		
AD plant availability	95.0%	95.0%
Clean-Up Plant availability	97.5%	97.5%
Total Availability	93%	93%
Biomethane to Grid (Flows)		
Biomethane Flow (Sm3/hr)	494	281
Propane Flow (Sm3/hr)	6.79	3.87
Total Gas Flow (Sm3/hr)	500	285
Total Gas Flow (Nm3/hr)	474.2171526	270.1600748
Biomethane to Grid (Energy)		
Annual Biomethane Production (Methane)	40.71934842	23.1976894
Annual Biomethane Production (Propane)	0.88	0.50
Annual Biomethane Production (Total)	41.60052313	23.69969197
Less Constraint / Capacity Issues	3%	47%
Annual Biomethane Production (Methane)	39.50	12.29
Annual Biomethane Production (Propane)	0.85	0.27
Annual Biomethane Production (Total)	40.35	12.56

Table 10 above shows scheme 1 for both projects. Asides from the capacity constraint for scheme 1, the properties in this section for each scheme for both projects are the same. This means each scheme receives the same amount of biomethane.

The model is based on a sales price of gas at the NBP of 1.96 c/kWh and an Ireland biomethane support tariff (equivalent to the UK Renewable Heat Incentive [RHI]) of €0.07/ kWh. For simplicity, the support tariff is not tiered, unlike the RHI in GB which has 40 million kWh/annum tiering. Tables 12 and 13 below show a simplified version of the biomethane export value.

Gas sales and support tariff revenue at Knockroe for an export biomethane flow rate of 285 scmh is approx. €2 million per annum and €1.1 million for scheme 1 with capacity constraint.

Gas sales and support tariff revenue at Glebe West for an export biomethane flow rate of 500 scmh is approx. €3.6 million per annum and €3.5 million for scheme 1 with capacity constraint.

Table 9: Glebe West annual income

Glebe West	Scheme 1 4 barg grid	Schemes 2 to 6	
Description			**Unit**
Value of biomethane export			
Gas basic sales value	1.96	1.96	c/kWh
Subsidy Price	7.00	7.00	kWh/annum
Annual Income - basic gas (incl Propane)	790,909	815,370	€/annum
Annual Income - basic gas (excl Propane)	774,156	798,099	€/annum
Annual Income - green premium	2,764,844	2,850,354	€/annum
Annual Income - total (incl Propane)	**3,555,753**	**3,665,725**	€/annum
Annual Income - total (excl Propane)	**3,539,000**	**3,648,454**	€/annum

Table 10: Knockroe annual income

Knockroe	Scheme 1 4 barg grid	Schemes 2 to 6	
Description			**Unit**
Value of biomethane export			
Gas basic sales value	1.96	1.96	c/kWh
Subsidy Price	7.00	7.00	kWh/annum
Annual Income - basic gas (incl Propane)	246,192	464,514	€/annum
Annual Income - basic gas (excl Propane)	240,978	454,675	€/annum
Annual Income - green premium	860,634	1,623,838	€/annum
Annual Income - total (incl Propane)	**1,106,827**	**2,088,352**	€/annum
Annual Income - total (excl Propane)	**1,101,612**	**2,078,513**	€/annum

8.3 Haulage Economics

The CAPEX and OPEX for haulage economics (show below) of the virtual pipeline schemes are calculated in sheet 9. 3 UMOE trailers were chosen for both projects since it proved to be the cheaper option giving a CAPEX for both projects of 750,000 euros. The average round trip for Knockroe is 12 miles and for Glebe West 39 miles. The distances are suitable and economically viable.

Table 11: Haulage economics

Factor	Knockroe	Glebe West	Unit
General Info			
GBP/EUR	1.13	1.13	-
CNG Annual Volume	2,281,254	4,004,328	Sm3/a
CNG Density at 1bara and 15C	0.709	0.709	kg/Sm3
CNG Mass Transported	1,618,345	2,840,713	kg/a
CNG delivered per trip	5,724	5,724	kg
Trailer trips per annum	94	165	-
Trips per annum	283	496	-
Average Round Trip between Mother and Daugher Station	12	39	miles
Truck MPG	8.0	8.0	-
Gallons of Diesel	1.50	4.88	gal/trip
Litres of Diesel	7	22	L/trip
Trailer Capacity			
Trailer Type	UMOE	UMOE	-
Water Capacity of Trailer	30,600	30,600	L
Working Pressure	250	250	bar
Residual Pressure	50	50	bar
Gas Temperature in Trailer (filling)	15	15	*C
Gas Temperature in Trailer (emptying)	15	15	*C
CBM Density (250 bar)	229.21	229.21	kg/m3
CBM Density (50 bar)	42.14	42.14	kg/m3
Loaded CBM Mass	7,014	7,014	kg
Residual CBM Mass	1,289	1,289	kg
Transported CBM Mass (not including residual mass)	5,724	5,724	kg
Transported CBM Volume (not including residual mass)	8,069	8,069	Sm3
Operating Cost			
Number of trailers	3	3	-
VOSA inspection	€120	€120	/annum
Annual MOT	€600	€600	/annum
6 weekly inspections	€3,500	€3,500	/annum
Cylinder inspection etc annually	€1,750	€1,750	/annum
Major test after 5 years , annual charge	€2,200	€2,200	/annum
Additional (tyres etc)	€2,750	€2,750	/annum
Ground storage inspections	€0	€0	/annum
Trailer Insurance	€5,000	€5,000	/annum
Sub Total for CNG Maintenance	**€47,760**	**€47,760**	**/annum**
CNG Haulage Cost			
Driver Wages	€300	€300	/trip
Management Services	€30	€30	/trip
Ops Licence	€12	€12	/trip
Insurance	€24	€24	/trip
Fuel at €1.1 per litre	€7	€24	/trip
Tractor Rental	€100	€100	/trip
Total Cost	€473	€490	/trip
Sub Total for CNG Haulage Cost	**€133,823**	**€243,108**	**/annum**
Total Operating Cost	**€181,583**	**€290,868**	**/annum**
Capital Cost			
CNG Trailer Cost	€230,000	€230,000	
Total CNG Trailer Cost	€690,000	€690,000	
Skeletal Trailer for Type 4 (1 off)	€20,000	€20,000	
Skeletal Trailers for Type 4	€60,000	€60,000	
Total CNG Trailer CAPEX	**€750,000**	**€750,000**	

8.4 CAPEX – Installation and Construction

Sheet *5* CAPEX covers the CAPEX investment of all the schemes. These are fixed costs based on the CSL data base from similar projects in GB (CSL has been involved in 15 projects injecting biomethane into 19/40/70 bar transmission pipelines). All the Schemes include costs for Biogas Production, costs for other equipment and third-party sites are different depending on the scheme as itemised in the table below. The CAPEX costs associated with the production can be scaled in the input sheet.

Table 12: Types of CAPEX required for each scheme

Scheme	1	2	3	4	5	6
Biogas Production Site						
- Consents, PM and Equipment	X	X	X	X	X	X
- Connection to Grid	X	X	X	X	X	X
- Service Connections	X	X	X	X	X	X
- Mechanical, E&I and Civils Install	X	X	X	X	X	X
CBM Compression Station			X		X	
Within Grid Compression Station				X		
CBM Daughter Station			X			
CBM Daughter Grid Connection			X			
CBM Trailers			X			

A summary of the CAPEX breakdown for Knockroe and Glebe West are shown in chart format in the figures below. Some observations include:

- Biogas production site accounts for majority of the CAPEX.
- Grid connection costs for scheme 2 are significant. This is due to the high-pressure pipeline cost required for the TX connection and therefore the most expensive scheme.
- Scheme 1 is the cheapest as expected due to it only being a 4-bar connection.
- The within grid schemes (4&6) are slightly cheaper than the virtual pipeline schemes respectively (3&5).
- The within grid CAPEX is 8.2m euros and 10.3m euros for Knockroe and Glebe West respectively.
- The cheapest total CAPEX for scheme 1 is 6.8m euros and 8.7m euros for Knockroe and Glebe West.
- The most expensive options for scheme 2 have a CAPEX of 22.5m and 11.3m euros for Knockroe and Glebe West.

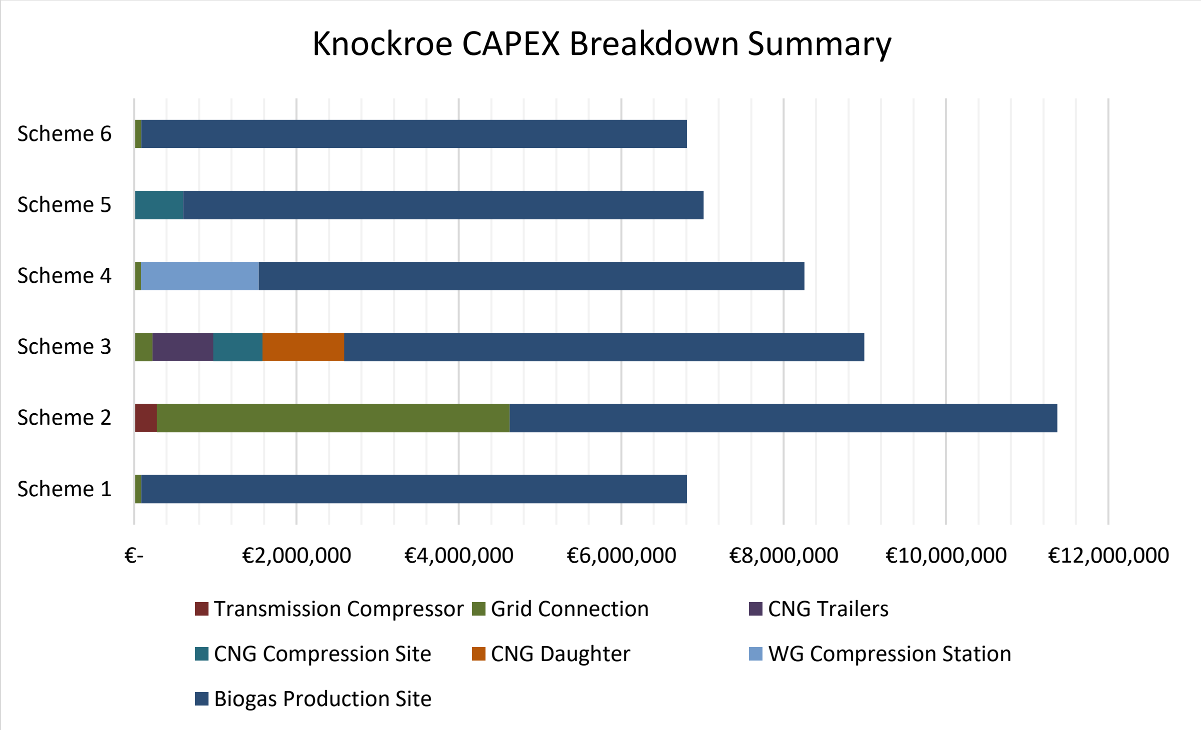


Figure 13: Knockroe project CAPEX

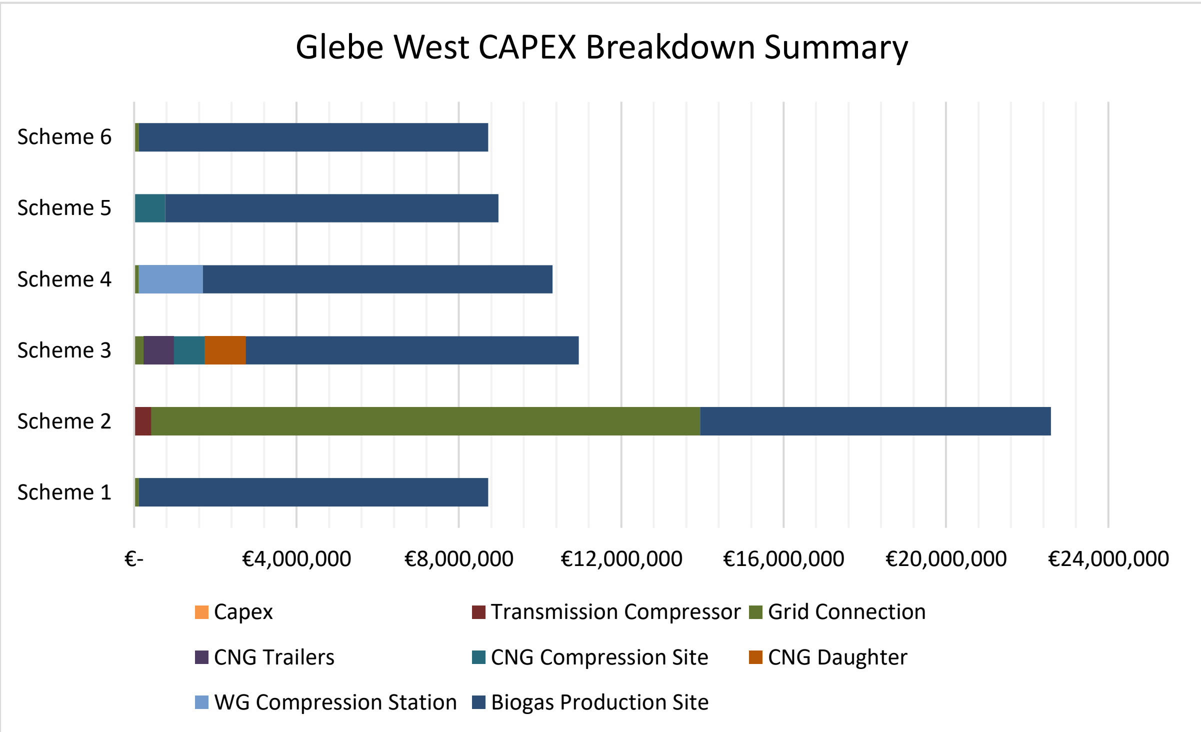


Figure 14: Glebe West project CAPEX

8.5 OPEX – Electrical and Maintenance

The OPEX costs are summarised in tab 6. OPEX. As with the CAPEX costs above each scheme different OPEX costs are required depending on the scheme. These include electrical and heating loads, maintenance, and operational costs. The OPEX costs associated with the production can be scaled in the input sheet.

Table 13: Types of OPEX required for each scheme

Scheme	1	2	3	4	5	6
Biogas Production Site – Electrical	X	X	X	X	X	X
CBM Compression Station – Electrical			X		X	
Within Grid Compression Station – Electrical				X		
CBM Daughter Station – Electrical			X			
Biogas Production Site – Maintenance	X	X	X	X	X	X
CBM Compression Station – Maintenance			X		X	
Within Grid Compression Station – Maintenance				X		
CBM Daughter Station - Maintenance			X			

Note that scheme 5 and 6 only have OPEX costs pertaining to the Biogas Production site as in these schemes the costs are accounted for in the GNI service charge as per the structure of the schemes. These costs are added onto the Financial Summary tab.

A summary of the OPEX breakdown for Knockroe and Glebe West are shown in chart format in the figures below. Some observations include:

- Scheme 1 is the cheapest to run due to the absence of compressor load.
- Virtual Pipelines Scheme 3 have the highest OPEX which is due to the cost of haulage.
- Scheme 4 is narrowly cheaper than Scheme 2 in terms of OPEX and is expected since the within grid compressors run for smaller periods of time.
- Schemes 5 and 6 are more expensive due to the GNI grid connection service provision and is where the CAPEX difference is recouped.
- The within grid OPEX is 990,000 euros and 665,000 euros for Knockroe and Glebe West, respectively.
- The cheapest OPEX (for scheme 1) is 930,000 euros and 600,000 euros for Knockroe and Glebe West.

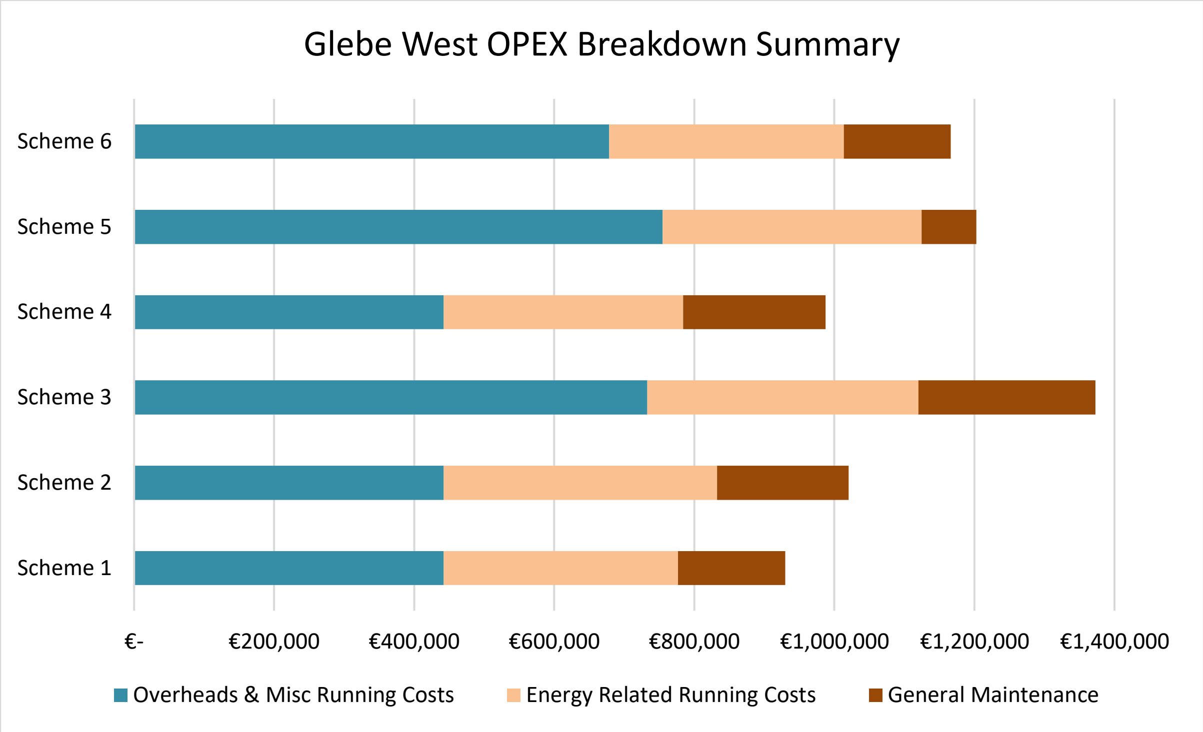


Figure 15: Glebe West OPEX

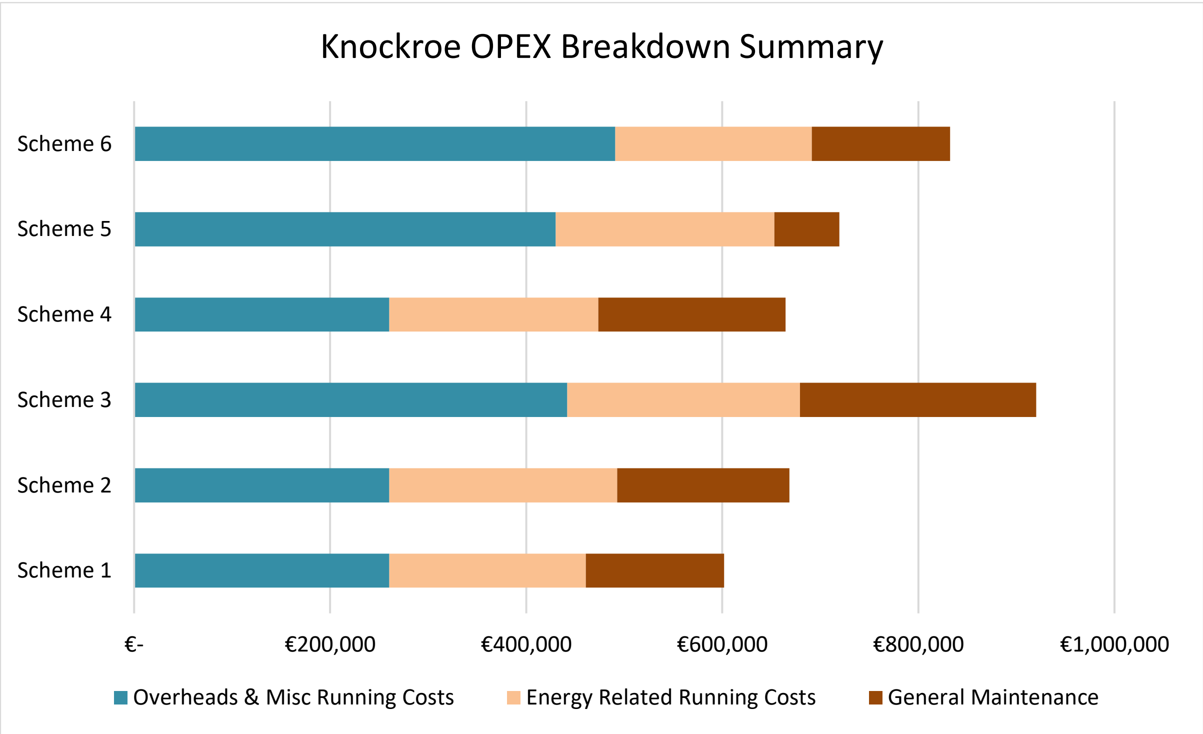


Figure 16: Knockroe OPEX

8.6 Financial Summary

The revenue, CAPEX, OPEX are summarised in sheet 4. Financials*.* All the CAPEX costs for each scheme have been financed with an interest rate of 9% over a period of 15 years. This results in an annual CAPEX finance costs which when coupled with the annual OPEX costs can be subtracted from the Income to give a total Annual Profit and a payback period for the CAPEX outlay.

For both biomethane projects the most lucrative scheme is the simple distribution network connection (scheme 1). This is to be expected as it is the scheme with the lowest CAPEX outlay and lowest ongoing OPEX. This proves true for Glebe West but is not the case for Knockroe due to its network capacity issues. For Knockroe within grid would be the most lucrative without any GNI ownership otherwise a virtual pipeline with GNI ownership would be. The financial summary of each scheme is as follows.

8.6.1 Knockroe

Scheme 1 (DX) for Knockroe does not have a positive payback period and scheme 2 (TX) has a payback period of 1246.9 years. Neither of these schemes are profitable. For scheme 1 the significant factor is the distribution capacity possible (53%) where distribution capacity is restricted due to local area constraints. Otherwise Scheme 1 would have a payback period of 10.6 years to be profitable. For scheme 2 the deciding factor is the transmission connection distance to the nearest TX point, 9.6km of HP pipeline. For payback period to approach a decade the distance would need to have been under 1km.

Scheme 3, the virtual pipeline model has a payback period of 171.48 years. This is tied directly to the daughter station CAPEX and OPEX costs. Since these costs are essential for the scheme unless funding is received for it, it would not be profitable. Alternatively, Scheme 5 virtual pipeline with GNI ownership has a payback period of 14.05 years. So, if GNI were able to offer the haulage and CBM daughter station as a service cost then the virtual pipeline does become viable.

Within Grid compression Schemes 4 and 6 are feasible schemes for Knockroe. Scheme 4 has a payback period of 20.66 years. If GNI offered the within grid compressor as a service cost (as per scheme 6) then the payback period for the biomethane connection would be 16.56 years and the project would make about 400,000 euros per annum. Without GNI ownership the within grid model is the most suitable for Knockroe.

In general, poor payback periods for a project like this are caused by the low biomethane export flow rate and the small size of the local gas network resulting in a high load factor. The annual profit once payback period has been achieved is 400,000 to 500,000 euros per annum for schemes 4,5 and 6. This is about 3 times less than the Glebe West model discussed in the next section.

Knockroe suffers from low capacity in its local gas networks when exporting gas. This results in a high load factor from a within grid compressor meaning there will be many hours of operation which demand operational costs. However, since schemes 1, 2 and 3 are not feasible if GNI did not take any ownership, within grid would be way forward.

		1	2	3
Scheme	**Base Case (No connection)**	**4 barg Grid**	**70 barg Grid**	**Virtual Pipeline**
Summary	**Base Case (No connection)**	**4 barg Grid**	**70 barg Grid**	**Virtual Pipeline**
Income	€ 2,088,352.22	€ 1,106,826.68	€ 2,088,352.22	€ 2,088,352.22
Operating Costs	€ 534,062.33	€ 601,848.41	€ 668,585.05	€ 920,120.02
Operating Profit (excl. Capital Finance)	€ 1,554,289.89	€ 504,978.27	€ 1,419,767.17	€ 1,168,232.20
Capital Costs	€ 6,722,308.12	€ 6,810,526.12	€ 11,370,795.50	€ 8,993,990.89
Capital Cost - Annual Finance	€ 833,962.03	€ 844,906.26	€ 1,410,648.18	€ 1,115,784.46
Total Annual Profit (taking Capex Finance & Opex into account	€ 720,327.85	-€ 339,927.99	€ 9,118.99	€ 52,447.74
Payback Period	**9.3**	**N/A**	**1246.9**	**171.5**

Figure 17: Results Summary Schemes 1 - 3

	4	5	6
Scheme	**Within Grid Compression**	**Virtual Pipeline (GNI Ownership model)**	**Within Grid Compression (GNI Ownership model)**
Summary	**Within Grid Compression**	**Virtual Pipeline (GNI Ownership model)**	**Within Grid Compression (GNI Ownership model)**
Income	€ 2,088,352.22	€ 2,088,352.22	€ 2,088,352.22
Operating Costs	€ 664,580.44	€ 719,205.59	€ 832,179.95
Operating Profit (excl. Capital Finance)	€ 1,423,771.78	€ 1,369,146.63	€ 1,256,172.27
Capital Costs	€ 8,255,526.12	€ 7,012,790.89	€ 6,810,526.12
Capital Cost - Annual Finance	€ 1,024,171.35	€ 869,999.00	€ 844,906.26
Total Annual Profit (taking Capex Finance & Opex into account	€ 399,600.43	€ 499,147.63	€ 411,266.01
Payback Period	**20.7**	**14.0**	**16.6**

Figure 18: Results Summary Schemes 3 - 6

8.6.2 Glebe West

Glebe West is a more viable project for a biomethane connection regardless of scheme. The income from the biomethane is much larger and able to cover the OPEX and CAPEX costs. Scheme 1 is viable for Glebe West and has a payback period of 5.7 years with an annual profit of 1.5m euros. This model has a larger biogas production and also the network has a higher distribution capacity possible (97%).

Scheme 2 for Glebe West is not viable since the nearest transmission connection is 31km away. The distance would need to have been about 1km for a similar payback period and annual profit to scheme 1.

The virtual pipeline models are profitable for Glebe West and better than the Knockroe model. Scheme 3 has a payback period of 11.7 years with an annual profit of about 900,000 euros. Scheme 5 has an annual profit of 1.3m euros and a payback period of 6.6 years. Again, the CAPEX and OPEX of running a daughter station makes this model less favourable compared to scheme 1 but would be a good alternative if need be.

The within grid models are very suitable for Glebe West and significantly better than if used for Knockroe. Scheme 4 has a payback period of 7.4 years with an annual profit of 1.39m euros. Scheme 6 has a payback period of 6.2 years and an annual profit of 1.4m euros. The payback periods are very reasonable, and the annual profit is attractive for investment. Whether the GNI ownership model is used or not, the within grid scheme is a very good alternative to scheme 1 and better than the other models.

		1	2	3
Scheme	**Base Case (No connection)**	**4 barg Grid**	**70 barg Grid**	**Virtual Pipeline**
Summary	**Base Case (No connection)**	**4 barg Grid**	**70 barg Grid**	**Virtual Pipeline**
Income	€ 3,665,724.64	€ 3,555,752.90	€ 3,665,724.64	€ 3,665,724.64
Operating Costs	€ 825,874.80	€ 929,754.62	€ 1,020,462.55	€ 1,372,914.38
Operating Profit (excl. Capital Finance)	€ 2,839,849.84	€ 2,625,998.28	€ 2,645,262.09	€ 2,292,810.26
Capital Costs	€ 8,611,405.21	€ 8,723,335.21	€ 22,587,205.40	€ 10,954,702.62
Capital Cost - Annual Finance	€ 1,068,321.31	€ 1,082,207.22	€ 2,802,143.46	€ 1,359,028.17
Total Annual Profit (taking Capex Finance & Opex into account)	€ 1,771,528.53	€ 1,543,791.07	-€ 156,881.37	€ 933,782.10
Payback Period	4.9	5.7	N/A	11.7

Figure 19: Results Summary Schemes 1 - 3

	4	5	6
Scheme	**Within Grid Compression**	**Virtual Pipeline (GNI Ownership model)**	**Within Grid Compression (GNI Ownership model)**
Summary	**Within Grid Compression**	**Virtual Pipeline (GNI Ownership model)**	**Within Grid Compression (GNI Ownership model)**
Income	€ 3,665,724.64	€ 3,665,724.64	€ 3,665,724.64
Operating Costs	€ 987,255.93	€ 1,202,811.46	€ 1,166,365.95
Operating Profit (excl. Capital Finance)	€ 2,678,468.71	€ 2,462,913.18	€ 2,499,358.69
Capital Costs	€ 10,308,335.21	€ 8,973,502.62	€ 8,723,335.21
Capital Cost - Annual Finance	€ 1,278,840.55	€ 1,113,242.71	€ 1,082,207.22
Total Annual Profit (taking Capex Finance & Opex into account)	€ 1,399,628.16	€ 1,349,670.47	€ 1,417,151.47
Payback Period	7.4	6.6	6.2

Figure 20: Results Summary Schemes 4 - 6

Glebe West would benefit from within grid compression if in operation for a few hours per day during the warm summer nights when gas demand is low. It shows to be an attractive option for providing capacity in areas with insufficient capacity on the 4-bar grid with comparable financials.

8.6.3 GNI Developer Ownership Models

The compression fee required for GNI ownership models were tested for different size compressors. Using the data for Knockroe and Glebe West, there is no impact on the compression fee if the size of the compressor and running hours were modified in the range of up to 1100 scmh. This means the compression fee will remain consistent regardless of the compressor size within a suitable range. Knockroe has a tariff for within grid compression of 0.96 c/kWh and Glebe West has a tariff of 0.57 c/kWh. The tariff for Glebe West stacks well against the virtual pipeline model which has a tariff of 0.8 c/kWh.

The GNI ownership works well for virtual pipeline models due to the high CAPEX costs of a daughter station. For within grid models GNI ownership sees a diminishing difference as biogas production increases. Smaller sites such as Knockroe see a bigger difference compared to Glebe West but will not be as good financially. The GNI ownership model works best for small virtual pipeline models but will lose value as the project size increases.

If the GNI Connection policy (producer pays 30%) is applied to the within grid model, as the biogas production increases the payback period decreases and annual profit increases. However, this has less of an impact on Glebe West compared to Knockroe. Glebe West will see a payback reduction of about 8 months whereas Knockroe will see a reduction of 4.7 years. They both see an annual profit increase of about 160,000 euros but the percentage increase in profit for Knockroe is 28% better since it has a smaller profit.

8.6.4 General Results

Scheme 1, a local DX network will typically remain the cheapest model. The deciding factor where this is not the case for this scheme depends on the volume of biomethane constrained per annum. If the constraint is less than 10% it will remain the cheapest within a range of 20 to 42 GWh of biomethane injection. At 50% or lower the project will not be feasible at all. Between 50% and 20% the payback period is not worth the investment. The scheme would need to have a constraint of 20% or lower to see a return in investment.

A number of sensitivities were run to determine in which scenarios a scheme is most suitable and pipeline distance was shown as the leading factor. The results are shown in the graph below. The analysis is based on a 500scmh plant but the similar results were seen for the 2 projects being considered in this report.

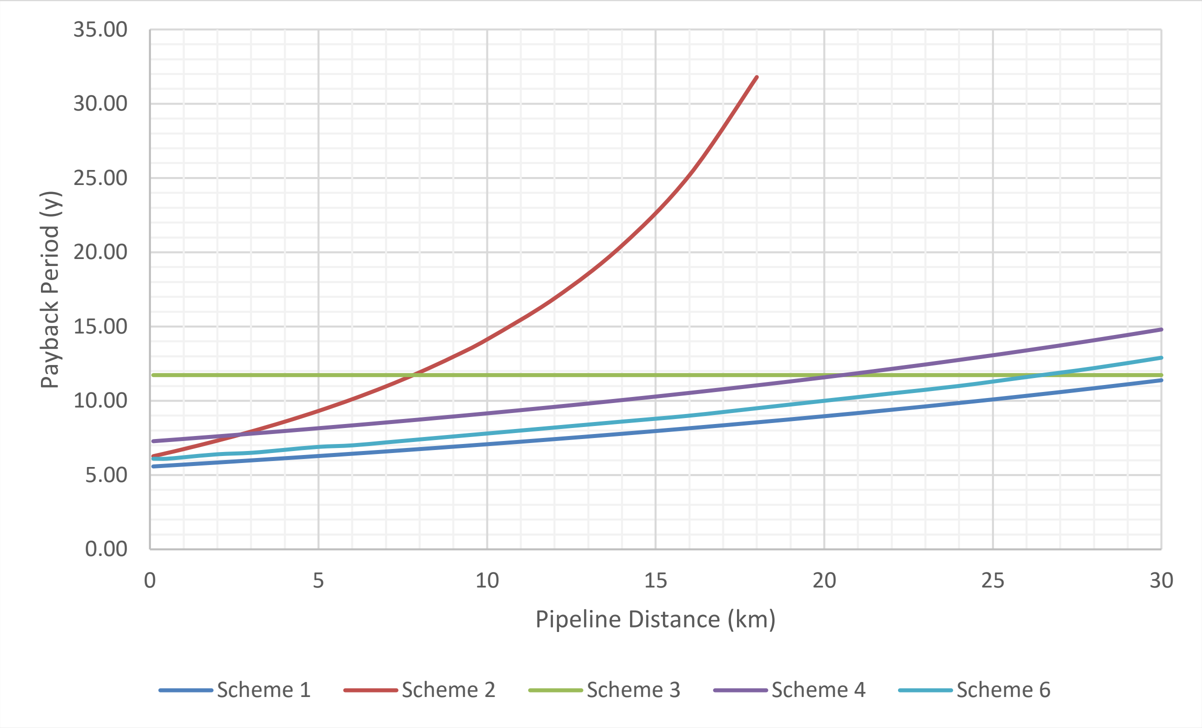


Figure 21: Pipeline Distance

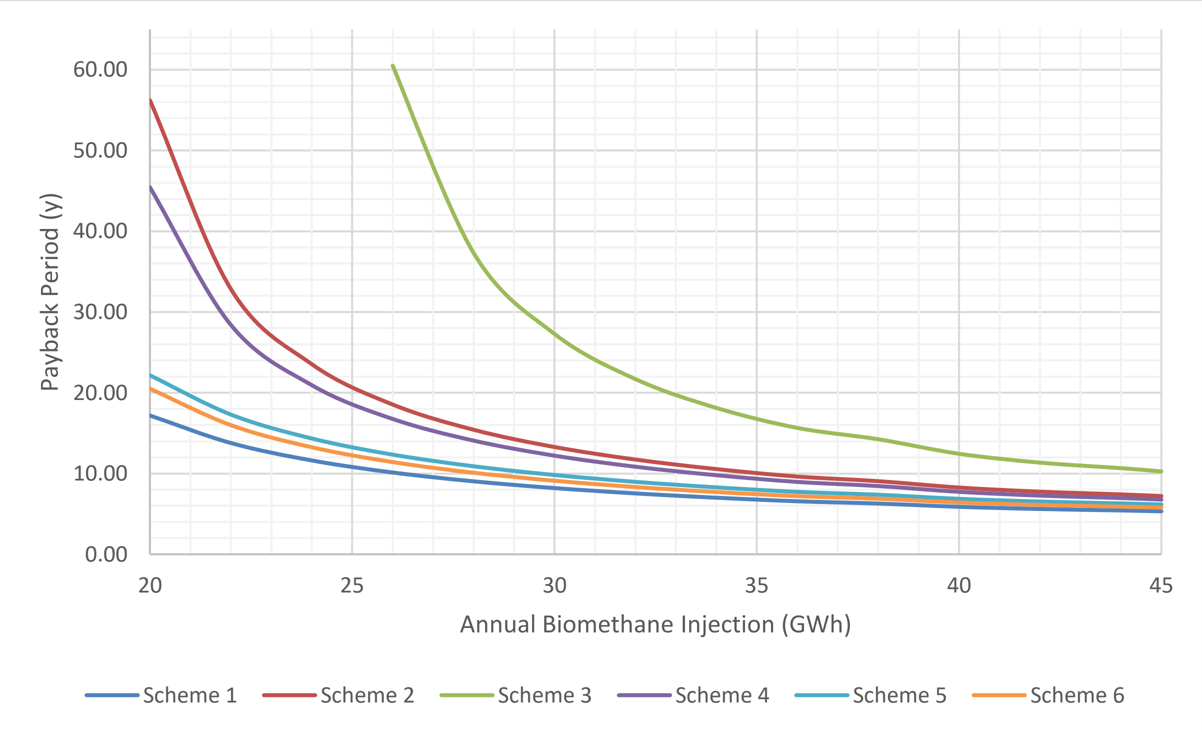


Figure 22: Biomethane Injection

Scheme 1 remains the cheapest solution but will lose against scheme 3 virtual pipeline at pipeline distances of greater than 30km.

Pipeline costs for TX models, scheme 2 increase significantly more than the other schemes due to high pressure requirement. Its viability is best when the pipeline distance is less than 5km. At distances less than 3km it is cheaper than scheme 4 within grid compression but not better than the GNI ownership model.

Scheme 3 is most economically viable when the TX connection distance is more than 8km and DX connection 30km. Scheme 3 loses against within grid when the DX connection for the within grid model is less than 25km. Trailer road trip distances were tested for scheme 3 and the differences were negligible compare to the rest of the project.

Scheme 4, within grid compression sees best economic viability when the pipeline distance is less than 15km. At distances more than 15km the virtual pipeline model starts stacking against it. The economic difference of scheme 4 compared to scheme 1 is not significantly different. Scheme 4 is best if the TX connection is more than 3km and the DX network has a constraint of more than 10% and within 15km of connection.

Figure 24 shows the economic viability of the schemes for annual biomethane injections from 20 to 45 GWh. As the amount of biomethane injected increases the economic gap between each of the schemes decrease. The viability worsens exponentially as biomethane injection decreases and at low injection rates scheme 3 is not viable at all.

Ultimately, if enough revenue generated from biomethane injection the economic gap decreases for each scheme so the project will depend on viability. If scheme 1 is not viable due to distribution capacity constraints, then the other schemes can be considered based on their distance to connection points.

9 Environmental Impact

The environmental impact of each potential biomethane connection for the various schemes was assessed in sheet 12 CO_2 Emissions.

The main areas of emissions for the projects were the heating and electrical requirements of biogas production and compression. Scheme 3 has an additional CNG haulage requirement from diesel emissions for the haulage of CBM trailers as required in Virtual Pipeline schemes. Scheme 1 does not require a compressor resulting in a smaller CO_2 emission.

The carbon intensity used for the Ireland electricity grid is 331.4 gCO2e/kWh. The carbon intensity of diesel used was 2680 gCO2e/ litre. No electrical loads for AD tanks were used in the calculation as they would be the same across all schemes. Scheme 3 (Virtual pipeline) was used as a baseline to compare the CO_2 emissions as it will always produce the most CO_2 due to haulage and higher compression requirements.

Scheme 1 produces the smallest amount of CO_2 emissions and Scheme 3 produces the most. From the study within grid compression produces more CO_2 the longer it is required to run. As a result, since Glebe West has a smaller run time compared to Knockroe, it produces less CO_2 as a percentage with respect to scheme 3. This makes scheme 4 better than scheme 2 for Glebe West since scheme 2 has a fixed compressor run time.

As the electricity grid is decarbonised the CO_2 impact of compressor running hours will fall significantly. In addition, the use of CBM to fuel trucks would remove the majority of emissions associated with haulage.

	1	2	3	4	
	4 barg Grid	**70 barg Grid**	**Virtual Pipeline**	**Within Grid Compression**	**Unit**
Biogas Production Electrical Requirement	1,581,916	1,865,279	1,581,916	1,581,916	kWh/annum
Biogas Production Heating Requirement	658,000	658,000	658,000	658,000	kWh/annum
CNG Compression Site Electrical Requirement	0	0	641,117	0	kWh/annum
CNG Daughter Site Electrical Requirement	0	0	87,600	0	kWh/annum
CNG Daughter Site Heating Requirement	0	0	115,988	0	kWh/annum
Within Grid Compression Site Electrical Requirement	0	0	0	358,649	kWh/annum
CNG Haulage Diesel Requirement	0	0	1,889	0	L/annum
Propane Injected	502,003	502,003	502,003	502,003	kWh/annum
Carbon Intensity of Ireland Electricity Grid	331	331	331	331	gCO2e/kWh
Carbon Intensity of Ireland Gas Grid	205	205	205	205	gCO2e/kWh
Diesel Calorific Value	37	37	37	37	MJ/L
Diesel Well to Tank	73	73	73	73	gCO2eq/MJ diesel
Diesel CO2 Combustion Emissions	2,680	2,680	2,680	2,680	gCO2/l
Propane Emission Factor	229	229	229	229	gCO2/kWh
Total CO2e Emissions	**774,049**	**867,955**	**1,044,350**	**892,905**	kgCO2e/annum
Percentage Emissions Saving (wrt Scheme 3)	**25.88%**	**16.89%**	**0.00%**	**14.50%**	

Figure 23: Knockroe carbon emissions per scheme using scheme 3 as a baseline.

	1	2	3	4	
	4 barg Grid	**70 barg Grid**	**Virtual Pipeline**	**Within Grid Compression**	**Unit**
Biogas Production Electrical Requirement	2,623,551	3,120,944	2,623,551	2,623,551	kWh/annum
Biogas Production Heating Requirement	1,155,000	1,155,000	1,155,000	1,155,000	kWh/annum
CNG Compression Site Electrical Requirement	0	0	993,033	0	kWh/annum
CNG Daughter Site Electrical Requirement	0	0	87,600	0	kWh/annum
CNG Daughter Site Heating Requirement	0	0	203,597	0	kWh/annum
Within Grid Compression Site Electrical Requireme	0	0	0	211,305	kWh/annum
CNG Haulage Diesel Requirement	0	0	10,775	0	L/annum
Propane Injected	881,175	881,175	881,175	881,175	kWh/annum
Carbon Intensity of Ireland Electricity Grid	331	331	331	331	gCO2e/kWh
Carbon Intensity of Ireland Gas Grid	205	205	205	205	gCO2e/kWh
Diesel Calorific Value	37	37	37	37	MJ/L
Diesel Well to Tank	73	73	73	73	gCO2eq/MJ diesel
Diesel CO2 Combustion Emissions	2,680	2,680	2,680	2,680	gCO2/l
Propane Emission Factor	229	229	229	229	gCO2/kWh
Total CO2e Emissions	**1,307,927**	**1,472,763**	**1,736,603**	**1,377,953**	kgCO2e/annum
Percentage Emissions Saving (wrt Scheme 3)	**24.68%**	**15.19%**	**0.00%**	**20.65%**	

Figure 24: Glebe West carbon emissions per scheme using scheme 3 as a baseline.

10 Conclusions

The results for Knockroe show schemes 1, 2 and 3 are not financially viable. Given the network demand size there is a significant capacity restraint on the 4-bar network making scheme 1 unviable. Scheme 2 requires costly amounts of high-pressure pipe. For scheme 3, the CAPEX of the daughter station is significant given the size of the project. The only financially viable options are schemes 4, 5 and 6. This is the within grid route, within grid with GNI ownership and virtual pipeline with GNI ownership. These however still have long payback periods of 10+ years. This is due to the low biomethane export flow rate and the small size of the local gas network.

The Glebe West project has a higher network demand and produces more biomethane. This gives the project good payback periods and generated revenue. The only unviable scheme is scheme 2 which is due to the 31km of high-pressure connection pipe. Scheme 1 is the best financially followed by within grid compression and then virtual pipeline. Within grid compression works well with Glebe West since there is a large capacity drop (with respect to 20-40 GWh of biomethane) from winter to summer. Therefore, the compressor can find a balance and operate for a few hours per day during the summer nights when gas demand is low.

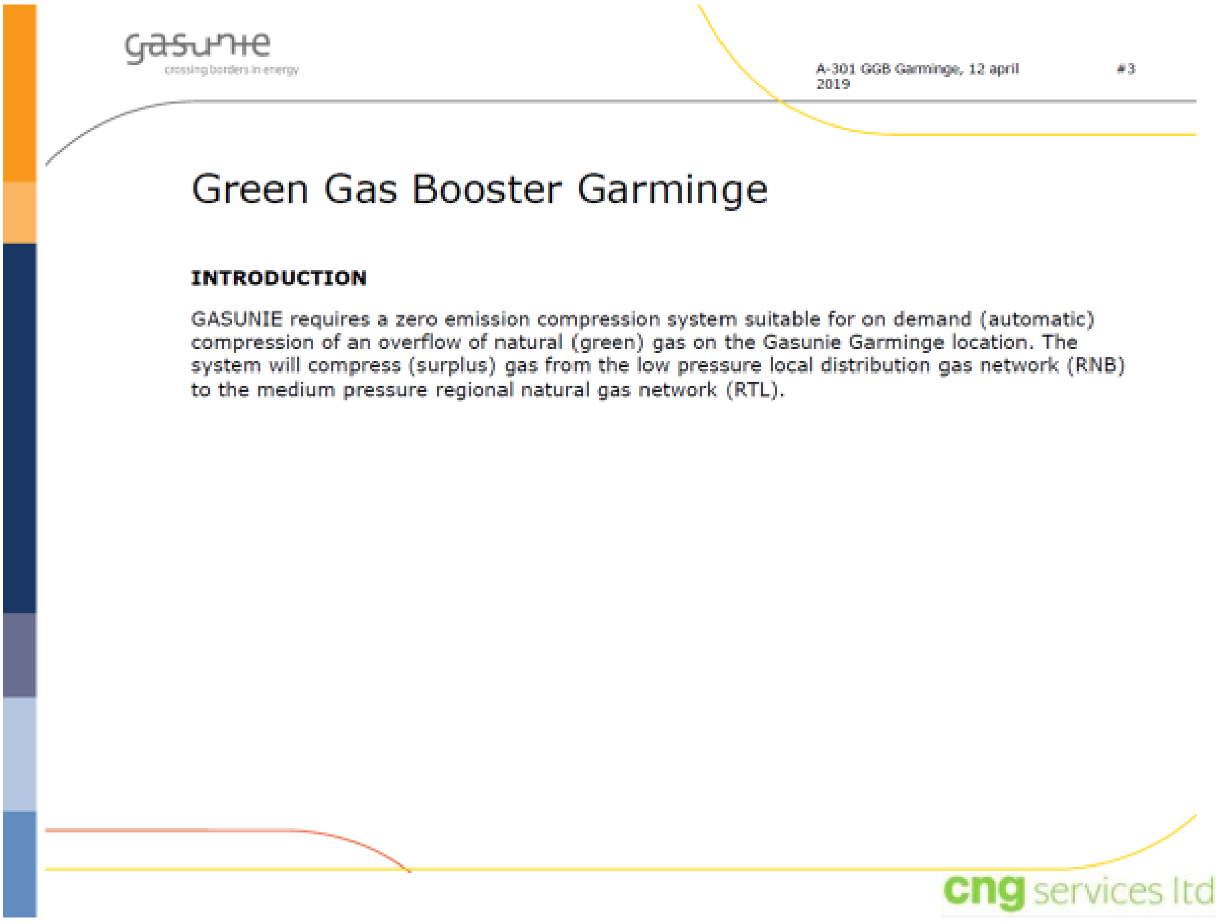
The GNI ownership models work well for virtual pipeline models due to converting high CAPEX costs of a daughter stations into OPEX. For within grid models GNI ownership sees a diminishing difference as biogas production increases and is less cost effective.

Some key trends that were found are:

- Under 30km of pipe, scheme 1 will be the best provided there are no capacity constraints.
- Scheme 2 requires minimal pipeline to be cost effective. However, at distances less than 3km it is cheaper than scheme 4 within grid compression though not better than the GNI ownership variant.
- Scheme 4 is best if the TX connection is more than 3km and the DX network has a constraint of more than 10% and within 15km of a connection.
- The numbers vary from project to project but the trends remain.

11 Appendix 1 – Gasunie within grid boosters - Garminge

The Dutch gas network (Gasunie) have installed within grid compressors on their network to provide capacity in the summer months. A test site has been built at Garminge near Groningen and the success of this has meant they now have plans to build more across the Netherlands. CSL undertook a site visit to Gasunie in summer 2019. The slides below provide a summary.



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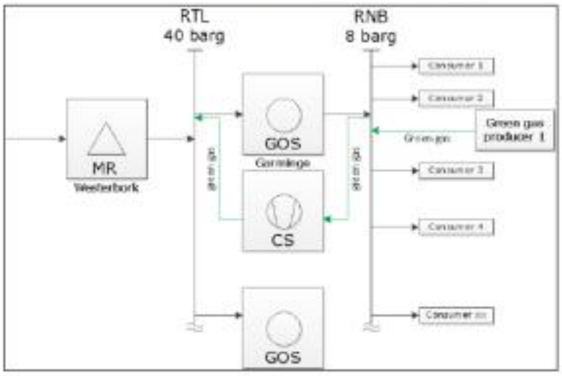
crossing borders in energy

A-301 GGB Garminge, 12 april 2019 #4

Green Gas Booster Garminge

Normally the natural gas flows from the Gasunie's Regional Transmission Pipeline (in Dutch: RTL, 40 barg) into a local distribution company (in Dutch: RNB, 8 barg) via the Gasunie's gas delivery station (in Dutch: GOS).

At the green gas feeding station CS Garminge, which is placed parallel to the GOS Garminge, green gas (bio-methane) will be fed from the local distribution network; Enexis, into the RTL with the help of compression. Attero, as the producer of green gas, feeds the green gas into the Enexis network. In Figure 1 is shown what the relation is between the parties.



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A-301 GGB Garminge, 12 april 2019 #5

Green Gas Booster Garminge

Table 1.Operating conditions and other parameters in relation tot the design of the systems.

Parameter	unit	RNB	RTL
P_{min}	barg	5,4	30
P_{max}	barg	8	40*
DP	barg	10	40
MOP	barg	8	40
MIP	barg	13	46
T_{min}	°C	5	5
T_{max}	°C	20	35

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A-301 GGB Garminge, 12 april 2019 #6

Green Gas Booster Garminge

- Note: Garminge is on/off the future boosters will be equipped with stepless capacity control.

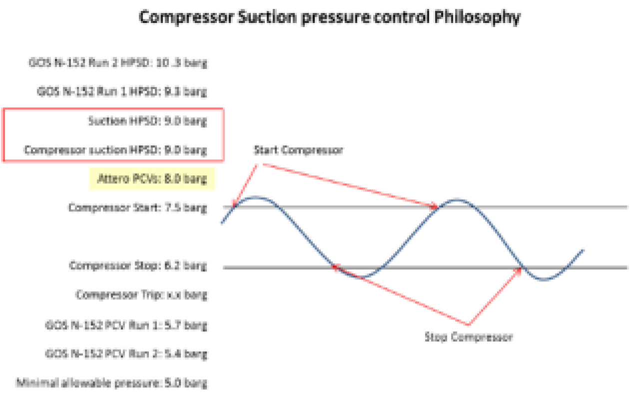

Figure 2. Compressor's suction pressure control philosophy

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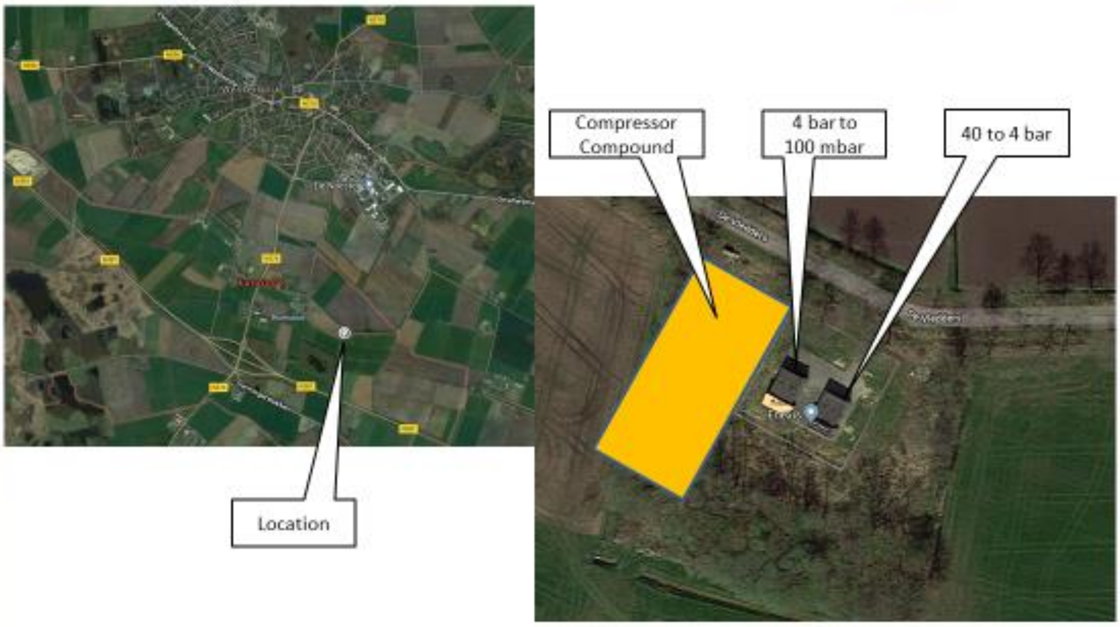
PRS/Compressor location near Garminge



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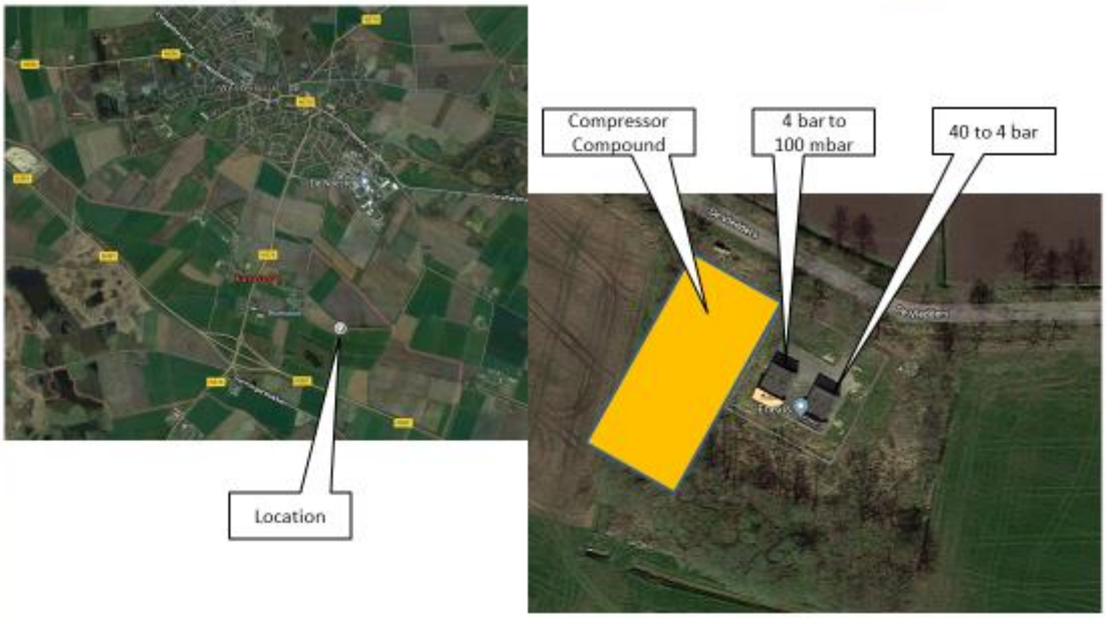
PRS/Compressor location near Garminge



Site Lower pressure (8 bar) inlet (1)

Site Lower pressure (8 bar) inlet (2)

Garminge does not have an inlet isolation valve (admitted as an error)

Active and monitor regulators act as Non Return Valves to protect high pressure gas flowing to 4 bar

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Reciprocating Compressor

Does not have variable sped drive – admitted as an error

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Site High Pressure (40 bar) Outlet

Outlet pipework with vent point but no isolation valve

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Heat Exchanger (1)

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Heat Exchanger (2)

Combined water and gas heat exchanger

Large low speed fan - very quiet