DECARBONISATION OPTIONS FOR THE DUTCH ONSHORE GAS AND OIL INDUSTRY

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Colophon

Decarbonisation options for the Dutch onshore gas and oil industry

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Contents

Summary

The onshore production of natural gas (NG) in the Netherlands has decreased significantly since 2012 due to the decision by the Dutch government to phase out production from the Groningen gas field, the largest gas field in the Netherlands. Even though production is being shut down, NG will continue to play an important role in the Dutch energy mix in the next decades, since industry and households will need it for heating and other applications. As such, the gas transport and distribution infrastructure will keep operating to ensure safe and secure energy supply. Furthermore, some of the infrastructure may be used for a future hydrogen grid.

This report gives an overview into the processes involved with onshore natural gas production, storage, transport and distribution and suggests technological options to decrease the greenhouse gas emissions related to their operations. The emissions associated with the onshore NG extraction, transport and distribution were about 200 kt CO_2 and 11 kt methane (corresponding to 320 kt CO_2-equivalent) in 2019.

Compressors and boiler pre-heaters at Gas Receiving Stations (GRS) are found to be the main consumers of NG and consequently to the main contributors of direct CO_2 emissions. Compressor units, control valves and other pneumatic controlled devices were found to contribute most to methane (CH_4) emissions, followed by venting practices due to safety, repair and maintenance activities.

Onshore oil production in The Netherlands is limited to only a few locations. The only traceable emissions associated with onshore oil production are those from steam production and oil treatment in Schoonebeek, and were about 165 kt CO_2 in 2019. Oil transport via pipelines was responsible for about 0.25 kt of methane (7 kt CO_2-equivalent) in 2019.

The decarbonisation options discussed were divided into reduce methane emissions, and reducing CO_2 emissions. Mobile recompression offers substantial reduction of CH_4 emissions due to repair and maintenance activities. Leak Detection and Repair (LDAR) and zero emission devices can reduce methane emissions from pneumatic devices. Electrification of compressors offers the highest potential to reduce the methane and direct CO_2 emissions from compressor units. Ground coupled heat exchangers along with vortex tubes were found to offer up to 88% decrease in NG consumption of the boilers.

Finally, the study also highlights the lack of publicly available data for the onshore oil and gas industry in the Netherlands. Another point noted is the absence of any public, recent, and up-to-date decarbonisation studies for the industry.

1 Introduction

This report describes the current situation for onshore oil and gas production in the Netherlands and the options and preconditions for its decarbonisation. Decarbonisation in the context of this study refers to the reduction or complete removal of fossil carbon derived greenhouse gases (GHG) such as CO_2 and CH_4 (methane) emitted as a result of the industry's operations. This should not be confused with the final product of this industry which also mainly constitutes of CH_4. The study is part of the MIDDEN project (Manufacturing Industry Decarbonisation Data Exchange Network). The MIDDEN project aims to support industry, policymakers, analysts, and the energy sector in their common efforts to achieve deep decarbonisation. The MIDDEN project will update and elaborate further on options in the future, in close connection with the industry.

Scope

Production locations:

1) Natural gas: the Groningen gas field has accounted for around 80% of the Dutch onshore natural gas (NG) production from 2011-2020 (NLOG, 2022). The field is set to shut down production in 2022/23. The emissions associated with the field are expected to drop with its closure. Apart form Groningen, there are almost 100 smaller NG production locations in The Netherlands. Their production volumes are expected to decline gradually, but nevertheless the production is expected to continue for the next decades (NLOG, 2022a).
2) Oil: the Schoonebeek oil reserve has accounted for about two-third of the Dutch onshore oil production from 2011-2020 (NLOG, 2022). The site includes a combined heat and power (CHP) plant.

Processes:

1) Natural gas: separation of NG, liquified natural gas (LNG) terminals, storage, compression, transport and distribution, production of nitrogen for gas processing.
2) Oil: oil, gas and condensate separation. Transport and storage of oil is not considered.

Products include:

1) Natural gas: NG and condensate.
2) Oil: oil, NG and condensate.

The main options for the decarbonisation of CO_2 and methane emissions are the following:

1) For CO_2 emissions:
   a. Electrification
   b. Direct integration of renewables
   c. Residual energy recovery
2) For methane emissions:
   a. Recompression
   b. Flaring
   c. Detection and repair
   d. New equipment

Timeframe of the study:

- Production lifetime of the installations without considering repurposing after their end-of-life.

Main focus of the study is natural gas production and distribution. The oil extraction activities are included in the emission figures, but not discussed in detail. The data apply to reference year 2019, unless otherwise mentioned.

Reading guide

Section 2 introduces the Dutch onshore natural gas and oil industry. Section 3 describes the current situation for natural gas and oil production processes in the Netherlands, while options for decarbonisation are systematically quantified and evaluated in Section 4. The feasibility of and requirements for those decarbonisation options are discussed in Section 5.

2 Onshore gas and oil production in the Netherlands

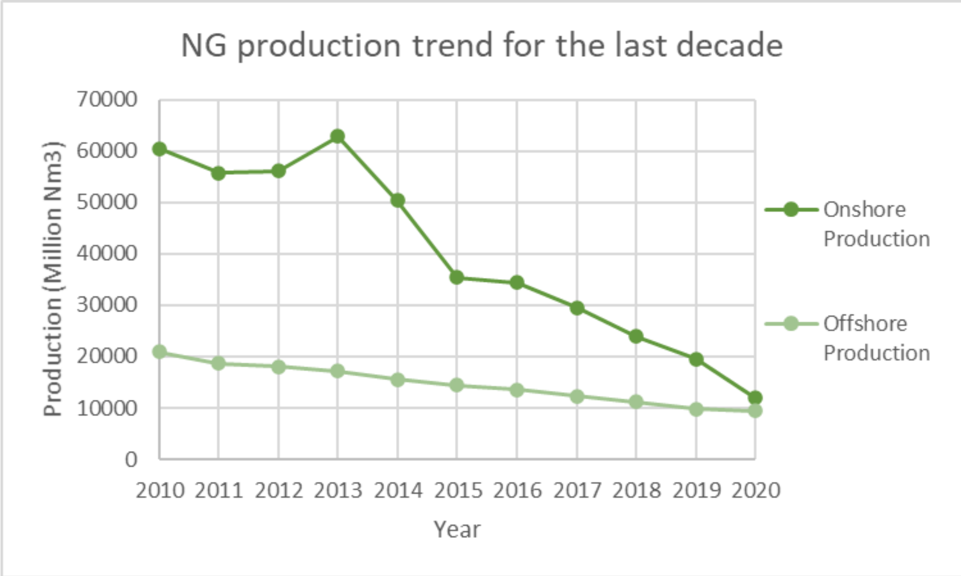
2.1 History

The Netherlands is the second largest gas producer in Europe after Norway (Beckman & van den Beukel, 2019). Until 2017, it produced enough gas to meet its domestic demand and be a reliable exporter to other European countries (Weijermars & Luthi, 2011). The discovery of Groningen gas field in 1959, one of the largest gas reserves in the world, defined the energy mix of Netherlands for the last six decades (Herber & De Jager, 2010). Gas extraction was quickly ramped up in the 1960s. Following this discovery, Gasunie, at that time a public-private joint venture between the Netherlands government and oil giants Shell and ExxonMobil, went on to build one of the largest state-of-the-art natural gas networks that covers the entire country (Milner, 1963). Natural gas quickly became the major source of energy for the Dutch industry and residential heating. The share of natural gas in the Dutch energy mix has remained steady at around 40% for at least the last two decades (Beckman & van den Beukel, 2019). In 2020, 41% of the energy requirements were met with natural gas of which 56% was extracted from onshore fields (EBN, 2022). In the same year, around 72% of the total onshore gas extraction was carried out from the Groningen field alone (TNO, 2020). This shows the dominant role this field has had in the everyday working of the country. Gasunie was split in 2005 into two companies. In 2022, Gasunie operates the gas transport system and is fully owned by the Dutch government. Gas trading is carried out by GasTerra. GasTerra is owned by the Dutch government for 50%, and by ExxonMobil and Shell, both for 25%.

The Netherlands enjoyed a secure natural gas supply until recently when the societal perception towards domestic NG extraction changed dramatically after 2012 (Mulder, 2018). An increase in extraction induced seismic activity was observed and the infamous earthquake of magnitude 3.6 on the Richter scale at Huizinge in 2012 led to limiting the production from the Groningen field. Another earthquake at Zeerijp in 2018 of magnitude 3.4 on the Richter scale led to the government's decision to entirely stop gas production from the Groningen field by 2022.

The total production in the Netherlands was 21,301 million m^3 in 2020 of which onshore production contributed around 56% (NLOG, 2022). Oil production in the Netherlands was 879,540 Sm^3 (standard cubic meter) in 2020 of which 47% was produced onshore (NLOG, 2022). Figure 1 shows the trend of gas production in the last decade and Figure 3 shows the trend of oil production.

Figure 1
NG production trend for the last decade (NLOG, 2022).

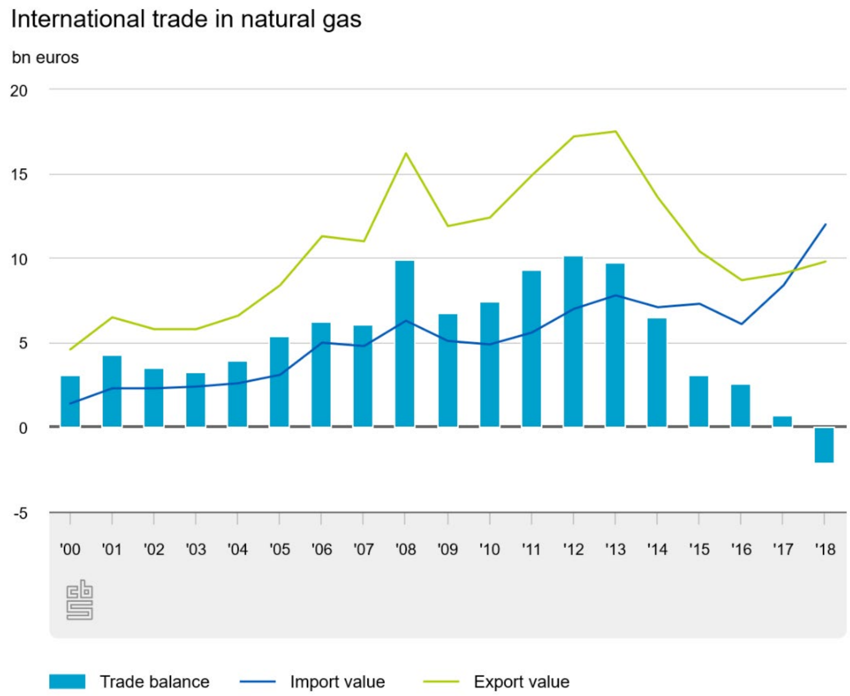


Nm³ is normal cubic meter. This corresponds to the volume at conditions when dry natural gas occupies a volume of 1 m³ at a pressure of 1.01325 bar and a temperature of 0° C.

The sharp drop in onshore NG production after 2013 can be attributed to the decision to halt production from the Groningen field due to increased seismic activity.

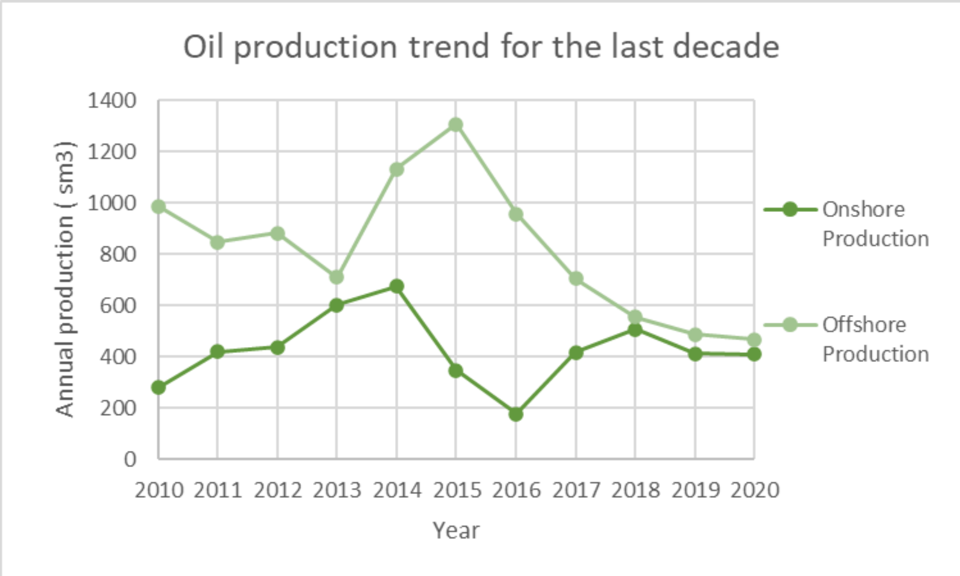
Since the discovery of the Groningen field, the Netherlands became a net importer of NG in 2018 for the first time. The imports of NG are only expected to increase due to the reduction in domestic gas. Figure 2 shows the trend of export and import of NG by the Netherlands.

Figure 2
The trend of imports and exports of NG in the Netherlands (CBS, 2019a).



The oil produced from offshore platforms is mainly a by-product of gas extraction activities. Schoonebeek oil field is the main extraction point of the onshore oil field. The oil production in the Netherlands is relatively small, producing less than 1% of its annual consumption, making it highly dependent on oil imports (CBS, 2019). Figure 3 shows the trend of onshore and offshore oil production.

Figure 3
Oil production trend for the last decade (NLOG, 2022).



2.2 Present and future

Total NG revenues for Dutch government were 1.1 billion euros (0.13% of GDP) in 2019 (CBS, 2020). The provisional figures for 2020 show a decline in NG revenues to 0.6 billion euros (CBS, 2020). The onshore gas industry has approximately 95 production fields still functional in 2021 (NLOG, 2022). The companies operating in the onshore NG industry classified into production, distribution and storage are as follows:

1) Production
    - Nederlandse Aardolie Maatschappij B.V. (NAM)
    - Vermilion Energy Netherlands B.V.
    - TAQA Onshore B.V.
2) Distribution: N.V. Nederlandse Gasunie
3) Storage:
    - EnergyStock B.V.
    - TAQA Energy B.V.
    - Nederlandse Aardolie Maatschappij B.V. (NAM)

Even though the gas production in The Netherlands has decreased dramatically over the past decade (see Figure 1), the demand for NG in Netherland will remain significant and reduce by about 26-33% in 2030 compared to 2019 (PBL, 2021). About 90% of residential heat and 40-50% of industrial heat is satisfied with NG (EBN, 2022). Decreasing production with a significant and steady demand has turned the Netherlands into a net importer of NG as of 2018 (EBN, 2022). The country now finds itself in a similar situation as other European countries, reliant on gas imports. Initially, the uptick in gas imports was attributed to higher gas imports from Norway. However, the imports from Norway have steadied and higher imports from Russia could be observed (CBS, 2019). 2022 has shown lower imports from Russia, a dramatic increase of prices and a lower NG demand.

The NG produced in the Groningen field is named Groningen gas or L-gas due to its low calorific value compared to the imported H-gas as well as the NG domestically produced from small fields (Market & Climate, 2019). The gas extracted from Groningen has a relatively high content of nitrogen (14%). The quality of NG based on its higher heating value can be specified with the Wobbe Index. The L-gas has a Wobbe index in the range of 43.46 – 44.41 MJ/Nm^3 whereas the Wobbe index for H-gas is in the range of 49.9 – 55.7 MJ/Nm^3 (IEA et al., 2020).

H-gas is used to supply NG to the large industries (Beckman & Van den Beukel, 2019). H-gas is domestically produced from small fields both offshore and onshore and is imported from Russia, Norway and through the LNG terminal at Rotterdam which received gas from Qatar, Algeria and the United States. L-gas is mainly used to supply almost all the residential heat demand and most of the industrial appliances. Apart from being produced from the Groningen field, it is also made by converting H-gas to L-gas by mixing nitrogen via conversion facilities operated by Gasunie (more details about this process and its energy use is in the MIDDEN report about industrial gases (Cioli et al., 2021).

Along with the technical limitations, the geopolitical implications of increasing reliance on Russia for gas imports also decreases the country's energy security (Patrahau & Van Geuns, 2021). The geopolitical influence of Netherlands is undermined by their economic reliance on Russia for NG. Apart from the geopolitical implications, the environmental implications of using imported H-gas have a negative impact on the global climate goals. Some experts speculate that compared to Dutch natural gas, Russian natural gas has a 30% higher carbon footprint (Patrahau & Van Geuns, 2021). The same is true for natural gas from most other countries (Cooper et al., 2021). Methane emissions associated with leakage, also known as fugitive emissions, are relatively higher in most countries compared to The Netherlands and methane emissions have a higher global warming potential than carbon dioxide.

2.3 Greenhouse gas emissions

One of the major sources of emissions in NG industry is the NG consumption of the facilities themselves (Tamez & Dellaert, 2020). NG is mainly consumed to power the gas fired compressors for compressing the gas to desired pressures and in pre-heating devices at Gas Receiving Stations (GRS, also known as gas delivery stations) to pre-heat the gas before reducing its pressure. Some gas fired compressors have already been replaced with electrical motor compressors such as on the production clusters on the Groningen field under the Groningen Long Term (GLT) project and at Wijngaarden compression station (CS). However, Gasunie still operates gas fired compressors at some of its compression stations and NG boilers at its gas receiving stations. Other sources of emissions are flaring and venting activities, leakages associated with the gas distribution network and equipment and the energy requirements of conversion facilities. These emissions can be classified as CO_2 emissions (from the combustion of fuel) and methane (CH_4) emissions (from leakages, flaring, venting etc.). For oil, the emissions relate to the production of steam for oil extraction.

2.3.1 CO_2 emissions

Figure 4 shows the development in CO_2 emissions of the onshore oil and gas industry. The total emissions have decreased from more than 1.6 Mt CO_2 in 1990 to about 370 kt CO_2 in 2019, due to emission reductions for all shown activities, and since 2013 also related to the reduction in NG production volume.

Figure 4
CO_2 emissions of the onshore oil and gas industry (Emissieregistratie, 2022). Emissions of oil transport via pipelines and of natural gas distribution is too small to be visible in this graph.

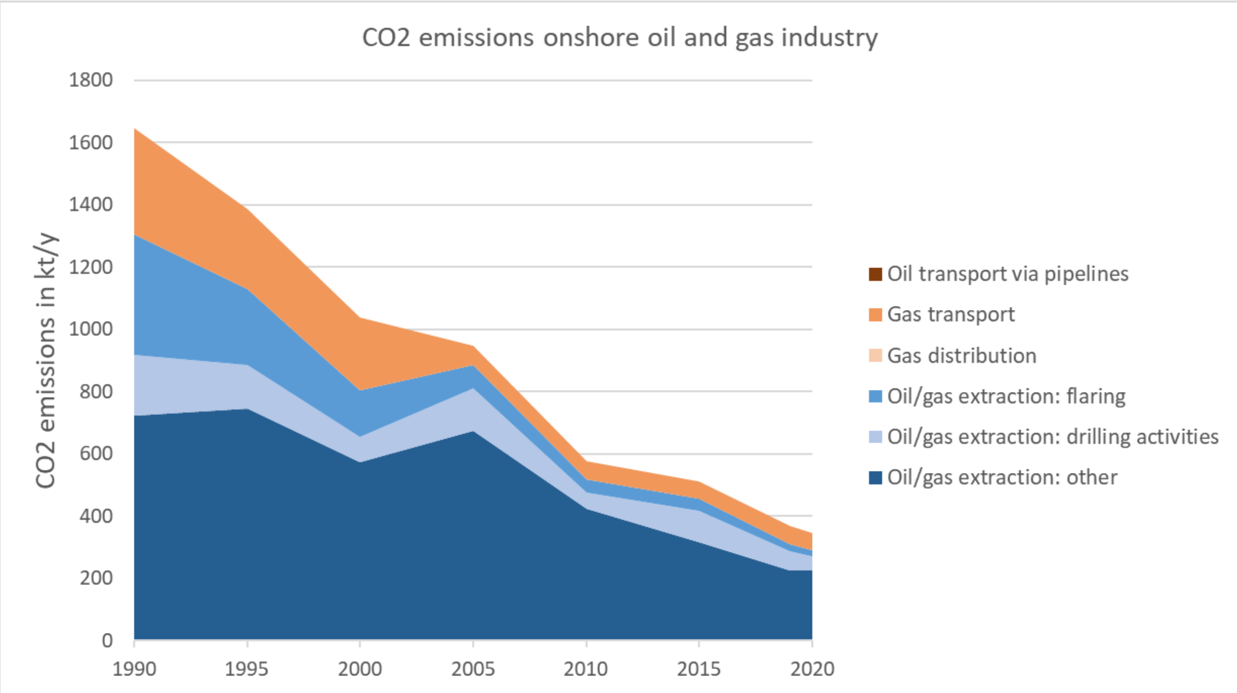


Table 1 shows the CO_2 emissions from the existing (as of 2019) natural gas processing and storage sites and Table 2 shows the CO_2 emissions from the Nederlandse Gasunie compressor stations. The emissions data was sourced from ETS reported emissions inventory which does not consider any methane emissions.

Flaring from all onshore gas facilities (production and processing) reported under NLOG in 2019 consumed 13.1 million Nm^3 (NLOG, 2022). If the LHV (lower heating value) and emissions factor for NG are considered to be 31.65 MJ/Nm^3 and 56.6 kg CO_2eq/GJ respectively (RVO, 2020), the total CO_2 emissions from the NG flaring from onshore facilities are 26 kt CO_2.

In 2019, all the onshore production and processing facilities reported under NLOG consumed approximately 112 million Nm^3 NG. Combustion of this volume of NG corresponds to emissions worth 223 kt CO_2. Natural gas is mainly consumed for the operation of gas driven compressors, engines and for the heating of facilities.

As observed in Table 1, NAM B.V. Warmtekrachtcentrale en Oliebehandelingsinstallatie Schoonebeek facility at Schoonebeek is the installation responsible for most onshore CO_2 onshore emissions. The site includes the largest oil producing facility of The Netherlands and a gas production facility. The facility houses a CHP plant which consumes NG to generate steam and power. The steam is used for oil extraction (NAM, 2006). NAM B.V. Gasproductie en gascompressie-installatie at Assen is the next highest contributor to CO_2 emissions. These emissions are a result of NG production and compression on the production cluster on the Groningen field. NAM B.V. at Den Helder is the location for the gas treatment and compression facility for the offshore gas receiving station.

The emissions associated with the NG storage sites are mainly from the gas consumption of compressors that compress the gas flowing to and from the storage. The emissions from LNG terminal and storage facility at Maasvlakte are mainly associated with the compression trains required to maintain the various stages of pressure throughout the liquefaction and regasification process (Håvard Devol, 2013).

Table 1
CO_2 emissions from onshore NG and oil processing facilities in the Netherlands in 2019.

Facility	Operator	Location	NG Consumption (1000 Nm^3) (NLOG, 2022)	Emissions 2019 (Kilotonnes CO_2 eq) (NEa, 2021)
N.V. Nederlandse Gasunie LNG Maasvlakte[a]	N.V. Nederlandse Gasunie	MAASVLAKTE	-	1.88
NAM B.V. Gasproductie en gascompressie-installatie[b]	NAM B.V.[g]	ASSEN	16,871.05	58.82
NAM B.V. Grijpskerk USG[c]	NAM B.V.	GRIJPSKERK	3,814.40	6.07
NAM B.V. locatie Den Helder[d]	NAM B.V.	DEN HELDER	4,743.86	16.46
NAM B.V. Norg USG[e]	NAM B.V.	LANGELO	2,374.62	6.13
NAM B.V. Warmtekrachtcentrale en Oliebehandelingsinstallatie Schoonebeek (WKC/OBI)[f]	NAM B.V.	SCHOONEBEEK	OBI: 7.50 WKC: 81,865.66	164.72
TAQA Onshore B.V.	TAQA Energy B.V.	ALKMAAR	565.62	1.31
TAQA Piekgas B.V.[e]	TAQA Energy B.V.	ALKMAAR	-	4.84
		Total	**110,242.71**	**260.23**

a) LNG terminal with LNG storage.
b) Onshore gas production and compression operated by NAM B.V. in the Netherlands.
c) Underground NG storage.
d) Gas treatment and compression plant for offshore fields operated by NAM. Includes the HighCal, LowCal and NOGAT facilities.
e) Includes the two facilities of Grijpskerk GDF and Grijpskerk USG.
f) Oil production facility (OBI) and the CHP (WKC) facility at Schoonebeek.
g) Nederlandse Aardolie Maatschappij B.V.

In the case of gas transport grid, compressor stations are responsible for about 23 kt CO_2 emissions. The breakdown of these emissions is provided in Table 2.

Table 2
CO_2 emissions from onshore NG compressor stations in the Netherlands in 2019.

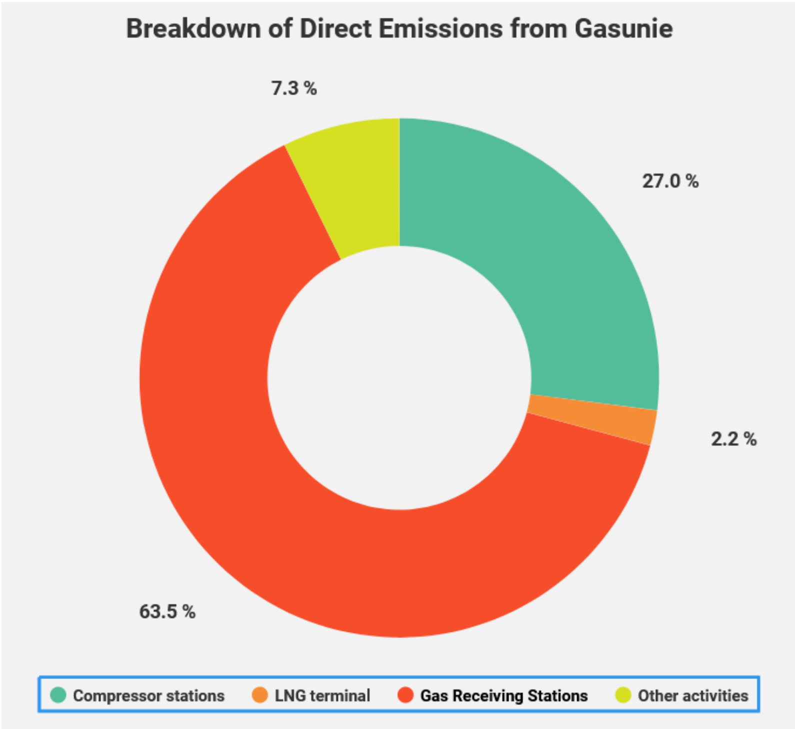
Facility	Operator	Location	Thermal input capacities (MW)[h] (EEA, 2021)	NG Consumption (TJ)[h] (EEA, 2021)	Emissions 2019 (Kilotonnes CO_2 eq) (NEa 2021)
Nederlandse Gasunie CS Alphen N.V.	N.V. Nederlandse Gasunie	ALPHEN	-	-	0.04
Nederlandse Gasunie CS Beverwijk N.V.	N.V. Nederlandse Gasunie	HEEMSKERK	3 x 51.2	2.31	0.40
Nederlandse Gasunie CS Oldeboorn N.V.	N.V. Nederlandse Gasunie	OLDEBOORN	-	-	0.02
Nederlandse Gasunie CS Ommen N.V.	N.V. Nederlandse Gasunie	VILSTEREN	(2 x 88.4) + (3 x 57.9) + (1 x 68.1)	35.91	3.24
Nederlandse Gasunie CS Ravenstein N.V.	N.V. Nederlandse Gasunie	RAVENSTEIN	2 x 51.2	24.21	3.12
Nederlandse Gasunie CS Spijk N.V.	N.V. Nederlandse Gasunie	SPIJK	-	-	1.43
Nederlandse Gasunie CS Wieringermeer N.V.	N.V. Nederlandse Gasunie	MIDDENMEER	-	-	13.10
Nederlandse Gasunie CS Zweekhorst N.V.	N.V. Nederlandse Gasunie	ZEVENAAR	(2 x 68.1) + (1 x 88.4)	10.72	1.59
Total			**73.15**		**22.94**

[h)] EEA only reports the consumption of compressors with thermal input capacities higher than 50 MW.

Apart from the compressors at compressor stations, the gas fired boilers at Gas Receiving Stations (GRS) operated by Gasunie in total are responsible for the consumption of approximately 30 million m^3 of gas every year (Gasunie, 2019). The total emissions from the NG consumption by GRS are around 53.7 kt CO_2.

According to Gasunie's annual report for 2019, the emissions associated with NG consumption for compression facilities, own heating purposes and for boilers at GRS in the Netherlands are 84.5 kt CO_2 (Gasunie, 2019). The emissions reported under ETS account for only 29% of the total emissions from Gasunie. The LNG facility at Maasvlakte accounts for another 2% of total direct emissions. As the emissions reported under ETS are a result of the NG consumption of the compressor stations, about 63% emissions are caused by the NG consumption by boilers at GRS to increase the temperature of gas to contractually agreed temperature (Gasunie, 2015). A small percentage (7%) of emissions are a result of flaring and Gasunie's own NG consumption for heating purposes. The breakdown is shown in Figure 5.

Figure 5
Breakdown of CO_2 emissions from Gasunie.



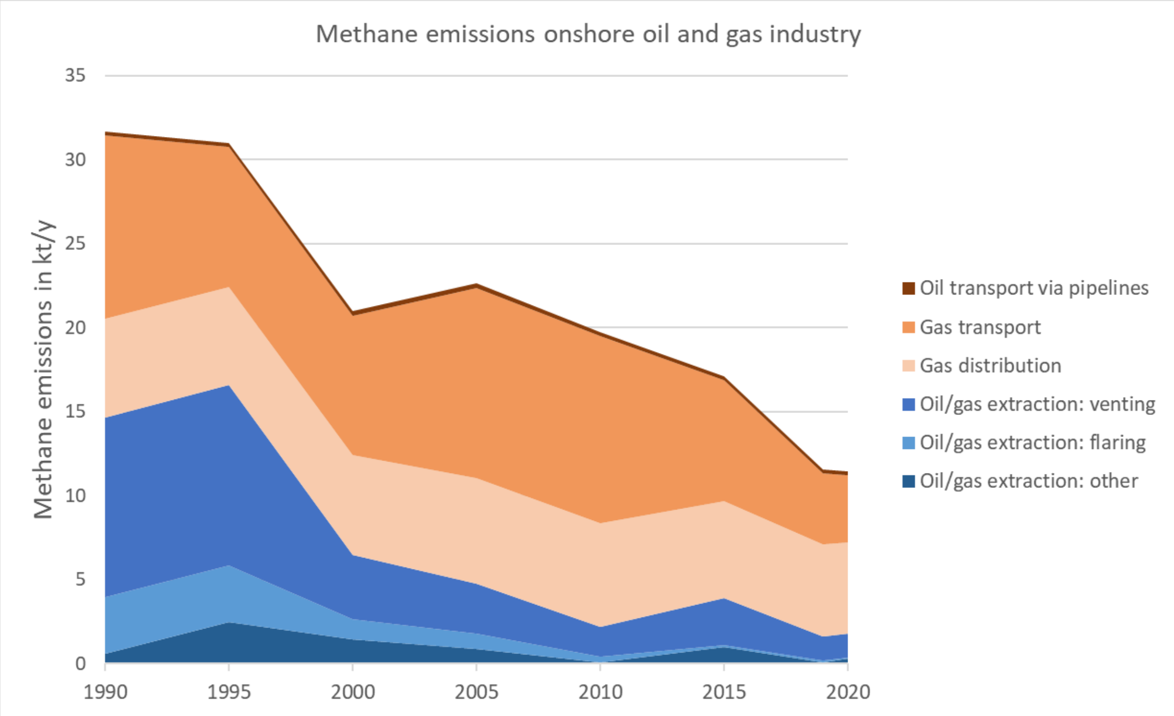
Emissions associated with the compressor stations have decreased overall compared to previous years (except the Middenmeer station) because less NG was transported within the Netherlands. Some compressor stations are also being temporarily decommissioned depending on the change in demand. For example the Oldeboorn station was temporarily decommissioned due to a decrease in demand from abroad for the Groningen gas (Gasunie, 2019). The compressor station at Middenmeer is mainly used for compressing the H-gas from small fields and abroad (Gasunie, 2019). Due to a large decrease in production from Groningen since 2018 and increasing imports, the station has had to compress more gas. The mixing/blending station at Middenmeer was also expanded in 2019 as a result of increased H-gas imports. The mixing station mixes nitrogen to H-gas from the small fields and abroad. As a result, the quantity of gas passing through the station in 2019 has increased from 230,000 m^3/hr to 310,000 m^3/hr, driving its NG consumption higher (Gasunie, 2019).

The emissions of boilers at the GRS of Gasunie are included above. There are also CO_2 emissions associated with boilers at GRS of the distribution grid, operated by local network companies. These are about 0.17 kt CO_2 per year (Emissieregistratie, 2022).

2.3.2 Methane emissions

Figure 6 shows the development of methane emissions of the onshore oil and gas industry since 1990. The emissions have decreased from more than 30 kt methane in 1990 to about 11 kt in 2020, mainly due to emission reductions in gas transport, flaring and venting.

Figure 6
Methane emissions of the onshore oil and gas industry (Emissieregistratie, 2022; TNO, 2018)



Methane emissions of NG value chain
The main sources of methane (CH_4) emissions from the NG value chain are described in Table 3 (GIE-MARCOGAZ, 2019).

Table 3
Main sources of methane emissions from the onshore NG value chain categorized into fugitive, venting and incomplete combustion emissions.

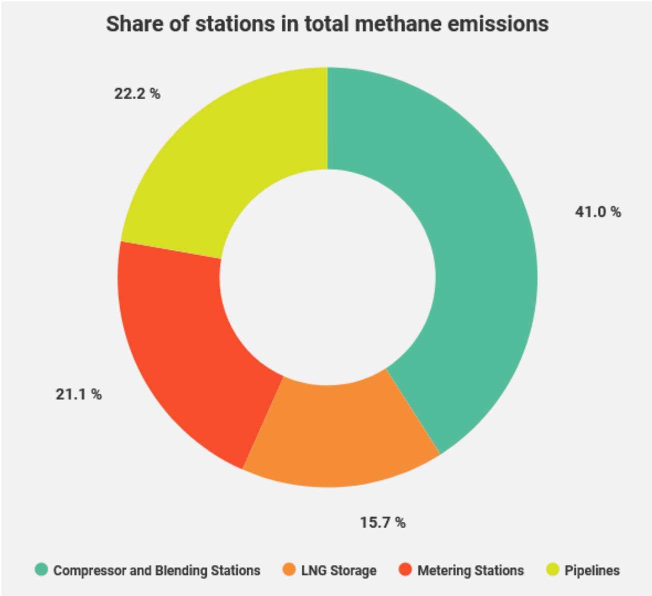
Process	Fugitive	Venting	Incomplete Combustion
Production	Components (valves, flanges, connectors, etc.)	Flaring Tank Storage; Compressors; Maintenance; Failure/Emergency; Glycol regeneration; Produced water handling; Pneumatic controllers	Flaring, Stationary combustion devices (e.g., gas turbines, engines, boilers); Turbo compressors
Liquefaction	Components (valves, flanges, connectors, etc.); Compressor seals	Flaring Tank Storage Vessels and truck loading Maintenance Failure/Emergency Start-up/Shutdown activities	Flaring; Stationary combustion devices (e.g., engines, boilers)
LNG carriers	Components (valves, flanges, connectors, etc.)	Tanks; Compressors; Gas freeing for dry-dock; Start & Stops	Engines (e.g., Methane slips)
Regasification	Components (valves, flanges, connectors, etc.)	Flaring Vessels and truck loading; Vessels unloading; Maintenance; Failure/Emergency; Pneumatic controllers	Stationary combustion devices (e.g., engines, boilers); Vaporisers; Flaring
Transmission & Storage (includes compressor stations, regulation and measurement stations, pipelines, underground storage)	Components (valves, flanges, connectors, etc.)	Compressors; Maintenance; Failure/Emergency; Pneumatic controllers; Devices for on-line gas quality sampling	Stationary combustion devices (e.g., engines, boilers) Engines/Turbines for gas compression Flaring

The methane emissions from the NG industry can be categorized in the following types:

1) Fugitive: Emissions due to leaks that occur unintentionally from equipment or components.
2) Vented: Emissions result from intentional releases of methane due to safety considerations, operational procedure or equipment design.
3) Incomplete combustion: Emissions due to small amounts of unburnt methane in the exhaust of natural gas combustion.

Coors et al. (1994) gives a breakdown of the methane emissions in 1989 (total methane emissions in 1989 were 6,500 tonne of CH_4 compared to 4,176 tonne of CH_4 in 2019) from the processes and equipment associated with the gas transport grid operated by Nederlandse Gasunie, shown in Figure 7 (Coors et al., 1994). Unfortunately, it was the only source available that gave a detailed breakdown of sources for methane emissions from the gas transport grid in the Netherlands. The following breakdown does not reflect the current situation and is only being discussed to have an idea of what can be expected.

Figure 7
Breakdown of methane emissions based on facilities in 1989 (Compressor & Blending Station, LNG storage plant, Metering station, Pipelines).



For the individual stations, the breakdown of methane emissions in 1989 is as follows (see Figures 8, 9 and 10):

Figure 8
Breakdown of methane emissions from a compressor station (1989).

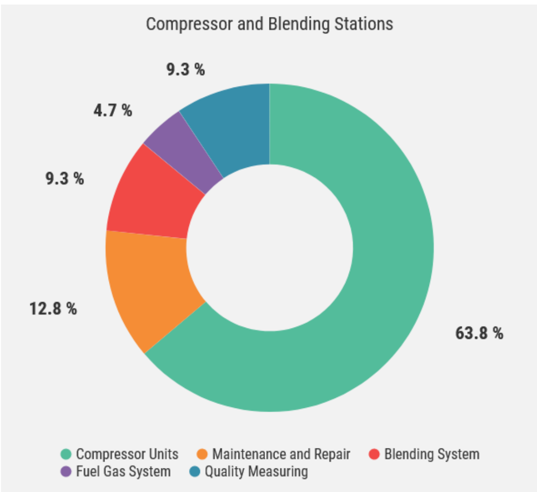


Figure 9
Breakdown of methane emissions from LNG plants (1989).

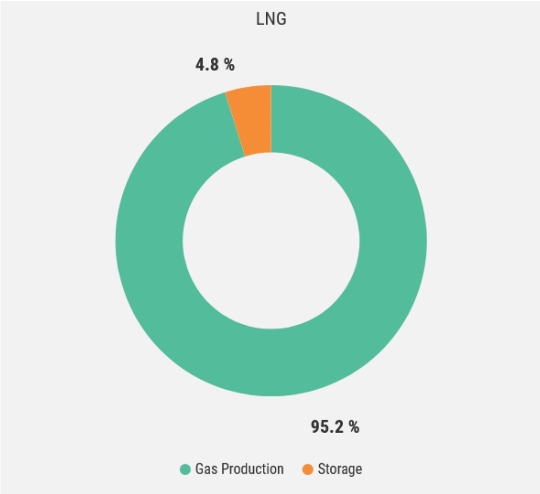
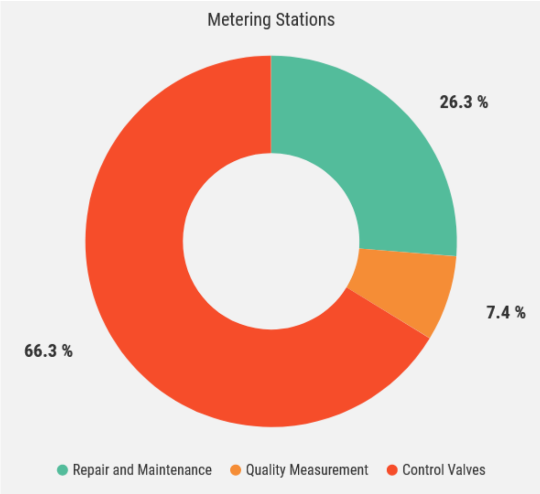


Figure 10
Breakdown of methane emissions from metering stations (1989).



Almost all methane emissions related to pipelines are due to venting.

Gas production
The Groningen field is a production cluster made up of 22 individual production sites. Despite being the largest NG producer in the European Union, the entire oil and gas industry in the Netherlands contributes around 3% to the total Dutch methane emissions which is less than the European Union contribution of 7% (of the total EU methane emissions) and far less than the global contribution of 22% (of the total global methane emissions) (Yacovitch et al., 2018). The small size of the country, short distances and well-maintained infrastructure could be possible reasons for the relatively lower methane emissions, as well as the large number of livestock in The Netherlands, which is also responsible for methane emissions. The methane emissions from the oil and gas industry are annually reported in National Inventory report as per the Kyoto Protocol. Within the oil and gas industry, onshore activities account for 16% of the total CH_4 emissions with direct venting responsible for the highest share of emissions. According to the inventory in 2017, methane emissions from the Groningen field account to around 2.3 kt of CH_4. If the global warming potential

over a span of 100 years (GWP_{100}) for CH_4 is assumed to be 28 times that of CO_2, as suggested by IPCC (2018), the methane emissions from Groningen field can also be expressed as 64.4 kt CO_2 eq.

However, Yacovitch et al. (2018) suggests that implementing inventory emission factors to onshore gas production is a poor estimate of individual gas production site emissions. For the same year i.e., 2017, their measurements suggest the methane emissions from the Groningen field are around 14 kt of CH_4 or 392 kt CO_2 eq. We nevertheless use the official numbers in this report.

Gas transport and distribution grid and LNG facility

According to Gasunie's annual report, methane emissions through network losses in 2019 were 4.2 kt CH_4 or 116.9 kt CO_2 eq if a GWP_{100} of 28 is used (Gasunie, 2019). Gasunie accounted for a fifth of the total methane emissions from the Dutch energy sector (Gasunie, 2019). These losses are equivalent to 0.01% of the total gas transported in the Netherlands. Table 4 shows the breakdown of the methane emissions from the compressor stations and the LNG facility at Maasvlakte. Table 4 accounts for around 43% of the reported methane emissions of Gasunie. Venting activities contributed to 1.4 kt CH_4 emissions accounting for 33% of Gasunie's methane emissions (Emissieregistratie, 2022). The breakdown for the remaining methane emissions was not found through publicly available literature. However, the remaining 23% of Gasunie's methane emissions can be attributed to fugitive emissions from metering and regulating stations, gas receiving stations and blending stations. For the distribution grid operated by regional companies such as Stedin, Liander and Enexis, the methane emissions in 2019 were 5.5 kt CH_4 (Kiwa, 2020; Emissieregistratie, 2022), corresponding to 155 kt CO_2-eq if a GWP_{100} of 28 is used. The emissions of the distribution grid have been at a roughly similar level since 1990, although they have been reduced by about 10% since 2010 (Kiwa, 2020).

The Middenmeer station is the only station that has seen an increase in its methane emissions compared to 2015. This can be explained by the fact that this station is used for compressing the H-gas from the small offshore fields and imported NG. As the production is decreasing and imports from Russia increasing, the Middenmeer station has been expanded and is compressing more gas than any other station. The highest decrease in gas can be seen from the Vilsteren station which was used for compressing the gas produced from the Groningen field. The decrease in methane emissions from other stations can be explained by the decrease in activity.

Table 4
Methane emissions from onshore NG compressor stations and LNG facility in the Netherlands in 2015 and 2019.

Facility	Operator	Location	Methane Emissions 2015 (tonne CH_4) (Emissieregistratie, 2022)	Methane Emissions 2019 (tonne CH_4) (Emissieregistratie, 2022)
Nederlandse Gasunie CS Alphen N.V.	N.V. Nederlandse Gasunie	ALPHEN	79.2	6.5
Nederlandse Gasunie CS Beverwijk N.V.	N.V. Nederlandse Gasunie	HEEMSKERK	202.9	117.0
Nederlandse Gasunie CS Oldeboorn N.V.	N.V. Nederlandse Gasunie	OLDEBOORN	118.9	53.8
Nederlandse Gasunie CS Ommen N.V.	N.V. Nederlandse Gasunie	VILSTEREN	636.0	261.5
Nederlandse Gasunie CS Ravenstein N.V.	N.V. Nederlandse Gasunie	RAVENSTEIN	258.2	113.1
Nederlandse Gasunie CS Spijk N.V.	N.V. Nederlandse Gasunie	SPIJK	166.9	121.4
Nederlandse Gasunie CS Wieringermeer N.V.	N.V. Nederlandse Gasunie	MIDDENMEER	276.7	471.5
Nederlandse Gasunie CS Zweekhorst N.V.	N.V. Nederlandse Gasunie	ZEVENAAR	89.6	84.6
N.V. Nederlandse Gasunie LNG Maasvlakte	N.V. Nederlandse Gasunie	MAASVLAKTE	760.2	575.3
Total			**2,588.6**	**1,804.8**

Methane emission of oil industry
Oil transport via pipelines was responsible for about 0.25 kt of methane (7 kt CO_2-equivalent) in 2019. Oil refining caused around 0.5 kt of methane (14 kt CO_2-equivalent) in 2019 (Emissieregistratie, 2022). Oil refining is described in more detail in Oliveira and Schure (2020).

2.3.3 Summary of emissions

The total CO_2 emissions of the onshore oil and gas industry as a result of NG consumption are 368 kt CO_2 in 2019. The emissions correspond to about 0.5% of the final NG consumption in The Netherlands.

The total methane emissions from the onshore oil and gas production, transport and distribution are 11.6 kt CH_4 in 2019, corresponding to about 0.03% of the NG consumption in The Netherlands. Considering GWP_{100}, the CO_2 equivalent emissions for the reported emissions are 325 kt $CO_{2,\ eq}$. Methane has a lifetime of about 12 years in the atmosphere. The generally accepted GWP over a span of 100 years underestimates the climate impact of methane over its short lifespan. The GWP for methane over a span of 20 years (GWP_{20}) is equivalent to 84 times of CO_2 (IPCC, 2018). The climate impact of reported methane emissions considering GWP_{20} will be 0.98 Mt $CO_{2,\ eq}$.

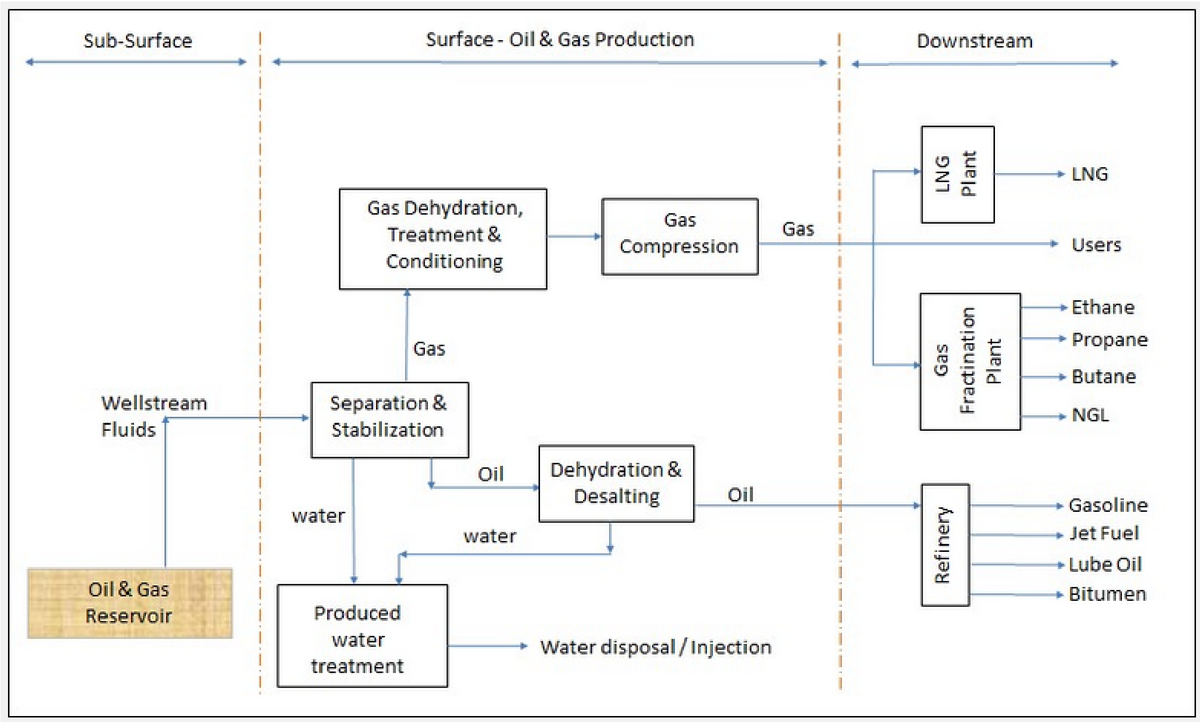
3 Onshore oil and gas processes

3.1 Production of natural gas

3.1.1 Extraction

The most important steps in oil and gas extraction are testing, delineation and production drilling which involves drilling rigs and equipment associated with it such as casing and tubing (World Bank, 1998). Oil and gas are moved upwards towards the surface either by their own pressure or by mechanically induced pressure. A typical oil and gas production schematic is shown in Figure 11.

Figure 11
Typical oil and gas production schematic.



3.1.2 Separation

Sometimes dry gas is extracted from wells that does not need separation. However, most times it is a combination of oil, water condensate, gas and contaminants. Once pumped on the surface, the oil, gas and water are separated. The crude oil is then piped or shipped to refineries for further processing to derive various products associated with mineral oil. Natural gas wells produce small quantities of condensate which are separated from the methane and other hydrocarbons in the gas. The produced gas can either be used directly or used as feedstock for manufacturing of fossil fuel derived chemicals.

For more detailed information of the types of separators and their technical specifications, we refer to Tamez & Dellaert (2020).

3.1.3 Compression

Compressors are used to compress NG in order to meet the specifications of the Gasunie gas transport grid. Unlike offshore production facilities, onshore production fields are closer to electricity grids and thus can be easily electrified. Production facilities on the Groningen field use electric compressors to compress NG. Centrifugal compressors were supplied by Siemens Demag Delaval with 23 MW variable speed drives supplied by Siemens.

For more detailed information of the types of separators and their technical specifications, we refer to Tamez & Dellaert (2020).

3.1.4 Dehydration

After compression, the gas goes through a dehydrator to remove any remaining water from the gas. This step is necessary to manage the water content in the gas according to the specification required by the gas distribution grid as it can result in corrosion of the pipelines or the formation of hydrates.

For more detailed information of the types of separators and their technical specifications, we refer to Tamez & Dellaert (2020).

3.1.5 Flaring and venting

Flaring is the process of combustion of NG in an open flame and venting is the process controlled or uncontrolled release of NG directly into the atmosphere.

Even though one would intuitively assume that losing gas in flaring or venting is not in the interests of the industry, certain economic, practical or safety situations make these activities a necessity. Flaring activities release CO_2 into the atmosphere and venting releases methane, which is a more potent GHG. Therefore, these activities have been strictly regulated in The Netherlands. These regulations have led to a large decrease in emissions associated with flaring and venting in The Netherlands compared to other gas producing countries.

For more detailed information on the activities and their technical specifications, we refer to Tamez & Dellaert (2020).

3.2 Processing

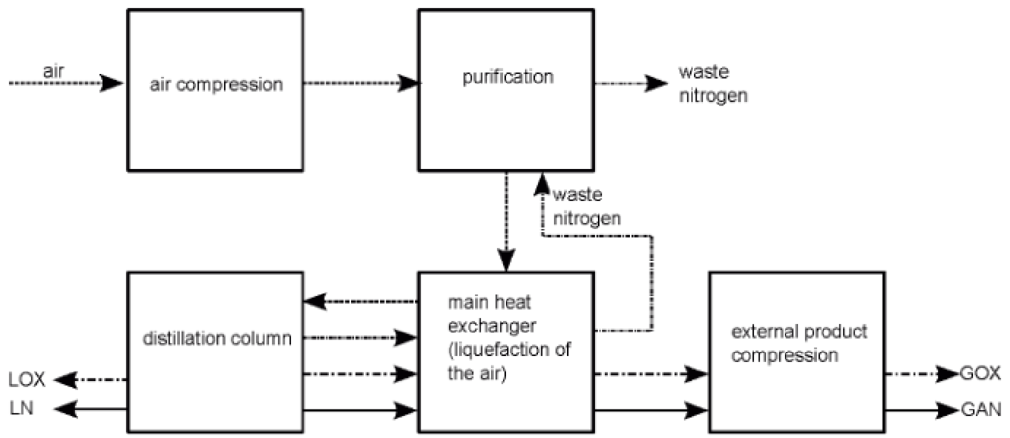
Various gas processing facilities like the gas purification facility at Emmen have been shut down or are in the process of being shut down owing to declining natural gas production in the Netherlands. Consortiums have been set up to figure out if these facilities can be repurposed for sustainable purposes such as a consortium of municipality of Emmen, EMMTEC services, New Energy Coalition, Gasunie and NAM are jointly investigating options to reuse the Emmen facility (NAM, 2021).

However, as domestic production is declining and imports of H-gas are increasing, the government has two options to deal with the different types of gases:

1) Gas market conversion: Involves upgrading the gas pipelines to transport H-gas and changing nozzles in gas utilization units. The upgradation of gas utilization units is expected to be around 200 euros per unit in Germany (Ministerie van Economische Zaken, 2015). With an estimated 5 million units in the Netherlands, the total cost of overhauling the gas utilization units alone is expected to be around 1 billion euros (Mozgovoy et al., 2015).
2) Gas conversion: The natural gas itself can be converted from H-gas to L-gas by either mixing L-gas into H-gas and reducing its Wobbe index, or by mixing in an inert gas like nitrogen or ballasting air in the H-gas until its Wobbe index reaches the required value for L-gas (Ministerie van Economische Zaken, 2015).

In the case of gas conversion, production of nitrogen needs a large amount of electrical energy. Nitrogen can be produced in multiple ways but the most prevalent method to produce it on a large scale is by separating it directly from air.

Figure 12
General layout of an air separation unit (Tesch et al., 2021).



LOX and GOX refer to liquid and gaseous oxygen, LN and GAN to liquid and gaseous nitrogen.

In the Netherlands, for the purpose of blending nitrogen with NG where a high capacity and high purity is required, cryogenic air separation units (ASUs) are preferred. A general layout is shown in Figure 12. There are two types of cryogenic ASUs:

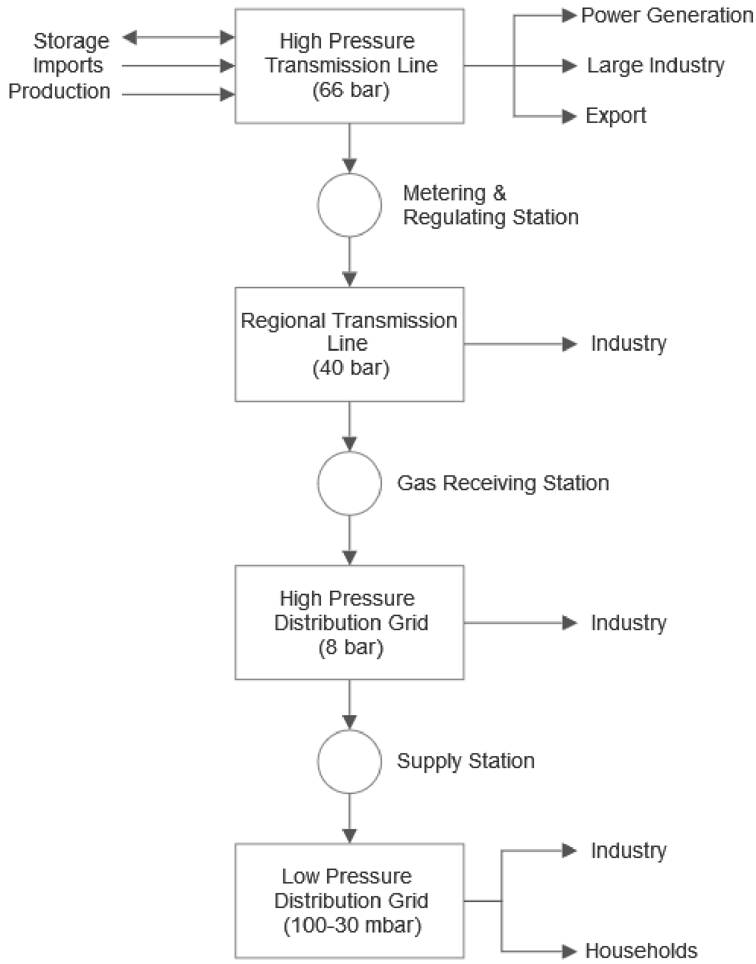
1) Low pressure ASU: Without an interstitial compressor system. Has lower energy consumption but the product is a gas at low pressure. Therefore, an external compressor is required to maintain the pressure of the gas as required. The specific energy consumption differs from manufacturer to manufacturer but usually it ranges between 0.16 kWh/m^3 to 0.3 kWh/m^3 (Tesch et al., 2021).
2) High pressure ASU: Comes with an interstitial compressor system. The product gas is at a higher pressure as required. The added compression results in higher specific energy consumption of the ASU. Specific energy consumption usually ranges between 0.35 kWh/m^3 to 0.55 kWh/m^3 (Tesch et al., 2021).

More information about ASU can be found in the MIDDEN report ‘Decarbonization Options for the Dutch Industrial Gases Production’ (Cioli et al., 2021).

3.3 Transport and distribution

The schematic for the Dutch gas network grid is represented in Figure 13.

Figure 13
Dutch gas transport and distribution system (Weidenaar et al., 2011; Netbeheer Nederland, 2019).



3.3.1 High-Pressure Transmission Lines

The high-pressure transmission lines (HTL) transport gas across the country and stretches over a length of 5000 km. It carries gas at a pressure of ranging between 43 to 66 bar. The HTL grid is divided into two parts, one for H-gas and the other for L-gas. The two grids are interconnected to each other through various conversion and blending facilities. The conversion and blending facilities are used to convert H-gas to L-gas. These grids transport gas produced in the Netherlands, the gas that is exported or imported into the country and transporting the gas to the storage facilities. The HTL also transports gas to large consuming sectors such as the industry and power generation facilities. A compressor station is required every 80-100 km to maintain the transmission pressure of gas. The compression is carried by using centrifugal compressors using either gas turbines or in some cases, electric motors. Gas fired compressors consume large amounts of NG and are responsible for a large proportion of CO_2 emissions associated with the distribution grid. The HTL is connected to Metering and Regulating (M&R) stations that form a link between the Regional Transmission Lines (RTL) network and export stations.

3.3.2 Regional Transmission Lines

The RTL network stretches over a length of 6000 km and its operating pressure ranges between 16 to 40 bar. At the M&R stations, the gas pressure is reduced to not more than 40 bar before supplying it to the RTL network. The M&R station also imparts the NG with its characteristic smell. NG in its base form is odourless. Imparting an odour makes it easier to detect gas leaks. The gas gets its typical smell from a chemical called tetrahydrothiophene (THT). The RTL are responsible for transporting the gas deeper into the country to reach places the HTL cannot reach. HTL and RTL are owned by Transmission Service Operator (TSO) Gasunie.

3.3.3 Gas Receiving Stations

The transfer from RTL to the distribution grids happens at approximately 1,300 Gas Delivery Stations or Gas Receiving Stations (GRS). The RTL supplies gas to the GRS which drops the pressure of NG to around 8 bar, which is appropriate for the distribution grids transporting gas over shorter distances. The GRSs are the feed points for the local energy utilities and industries. Lowering the pressure from 60 bar (HTL) to 40 bar (RTL) and then from 40 bar (RTL) to 8 bar also decreases the temperature of the gas. In order to avoid the formation of hydrates, water and liquid hydrocarbons, the gas is preheated to contractually agreed terms before supplying. This is carried out by using gas fired boiler heat exchangers. The heat exchangers provide heat to the gas so that its temperature remains above the dew point temperature after the pressure drop.

3.3.4 Local distribution grid

The local grid that connects the individual customers to the main grid is owned by local distribution companies (LDCs) or distribution service operators (DSOs). To reach every household, finer distribution grids are required, and the pressure maintained in these is around 100 to 30 mbar. The distribution grid maintaining a pressure of 8 bar feeds the gas to the supply stations or district station (there are about 10,000 of these in the Netherlands), which bring the pressure further down to the required levels so the gas can be supplied to the households (Netbeheer Nederland & Kiwa, 2016).

The grid has been providing a robust service to the Dutch gas market for at least the last half century. The gas distribution grid is even older and did partly already exist before there was natural gas production in The Netherlands. Before the 1960s these grids were supplied by town gas from gas manufacturing plants. With changing times, the grid must also adapt to the changes (Weidenaar et al., 2011). Table 5 shows a table of the anticipated changes in the future for the gas grid.

Table 5
Anticipated future for the gas grid (Weidenaar et al., 2011).

Current Situation of grid	Future expectations of grid
Mono gas grid (only NG)	Multi gas grid (NG, green gas, hydrogen, CO_2)
Top-down gas supply chain	Bi-directional gas supply chain
Focused only on NG grid	Interaction with electricity and heat distribution grids necessary
Passive nature of grid	Smart grids that actively monitors producers, consumers and prosumers

3.3.5 Export Stations

Export stations supply gas to Belgium, France, Germany, Italy, England and Switzerland.

3.4 Oil production

The technology used by NAM in Schoonebeek is non-vertical drilling and steam injection at low pressure (20-40 bar) (NAM, 2006).
The activities can be separated in five parts:

- Water supply and purification for steam production
- Steam production in CHP and treatment of oil/steam mixture in oil treatment facility (OBI)
- Oil extraction based on steam injection
- Disposal of oil
- Disposal of water.

The environmental report (NAM, 2006) describes the activities in Schoonebeek in more detail.

4 Options for decarbonisation

To combat climate change, the Dutch Government plans to reduce the country's GHG emissions by at least 55% by 2030 compared to 1990 levels and reach climate neutrality by 2050. To achieve these goals, it is helpful to find options for decarbonization of the onshore oil and gas industry. As NG extraction is being shut down and reliance on import increasing (CBS, 2019), the emissions associated with gas extraction within The Netherlands will soon be negligible. As long as NG is consumed in The Netherlands, emissions associated with gas extraction will happen abroad. The emissions associated with gas distribution and conversion would still play a role for some time in The Netherlands as the demand for NG will decrease much more slowly. Thus, it is important to consider these emissions while formulating the decarbonisation pathways. Apart from the available technical solutions to reduce emissions, the Dutch government is actively trying to replace NG in the energy mix (Hof, 2018). Electrification (based on electricity from non-fossil sources) and hydrogen are the most preferred options as of today. Hydrogen adoption will likely involve a national distribution grid similar to NG (although possibly with a smaller grid density and transported volume).

The options for decarbonisation are subdivided in the reduction of methane emissions, the reduction of CO_2 emissions and the replacement of NG in the network.

4.1 Reducing methane emissions

4.1.1 Mobile flaring

Description

Gas that was to be vented can instead be flared by using a mobile flaring unit. Burning methane has a comparatively lower environmental impact than releasing it.

Benefits

In 2018, Gasunie flared 872,000 Nm^3 NG and avoided approximately 11.2 kt of CO_2 equivalents in emissions by implementing the mobile flaring unit (Gasunie, 2019).
By targeting the venting emissions, the 1.4 kt of CH_4 emission can be flared and emissions up to approximately 35 kt $CO_{2,\,eq}$ can be avoided (after subtracting the CO_2 emissions from flaring, which would be about 4 kt CO_2).

4.1.2 Leak Detection and Repair (LDAR)

Description

LDAR program undertaken by Gasunie focuses on tracking down and repairing leaks at various Gasunie sites such as the compressor stations, metering and regulating stations, gas receiving stations and high-pressure valve locations (Gasunie, 2019). According to Gasunie, LDAR is based on the NEN-EN 15446:2008 (en): "Fugitive and diffuse emissions of common concern to industry sectors. Measurements of fugitive emission of vapors generating from equipment and piping leaks" (Bekker, 2011).

Bekker (2011) states that the LDAR program typically consists of the following three steps:

1) Preparation: Preparing the inventory by importing all the data gathered into a database.
2) Measuring and first repair attempt: Initial measurement is conducted and the first repair attempt consisting of simple corrective maintenance actions is executed. Another round of measurements is conducted to check the result of the first repair attempt.
3) Reporting: All the data is gathered and presented in a LDAR report.

Before conducting the repair, the environmental and economic impact of the repair activities is compared to the impact of the found leakage.

The potential leakage sources in the transport grid identified so far by Gasunie through LDAR is shown in Figure 14.

Figure 14
The type of leakage sources in the transport grid (Bekker, 2011)

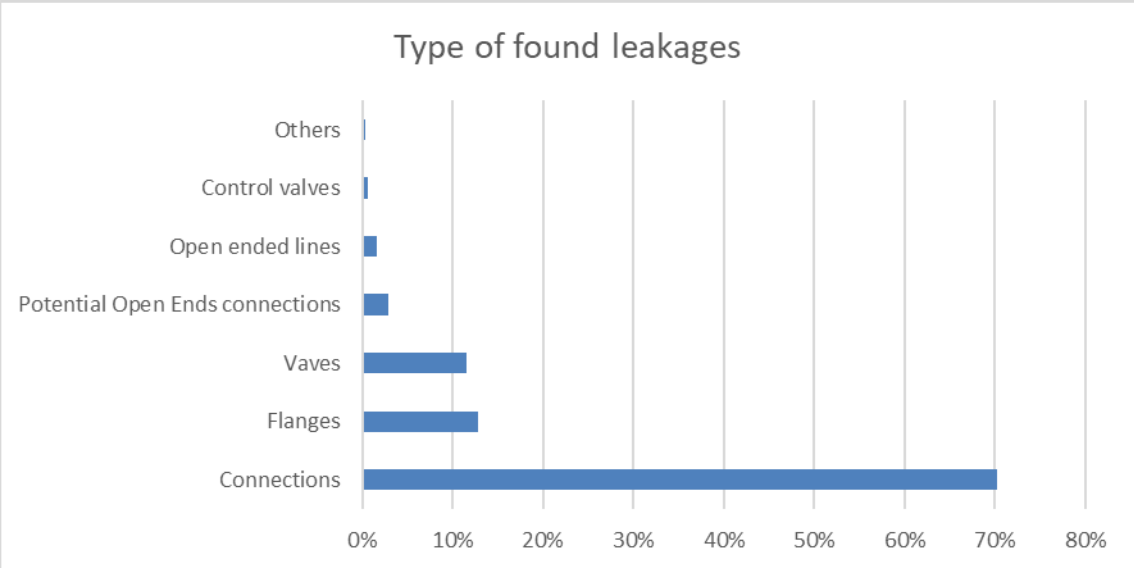
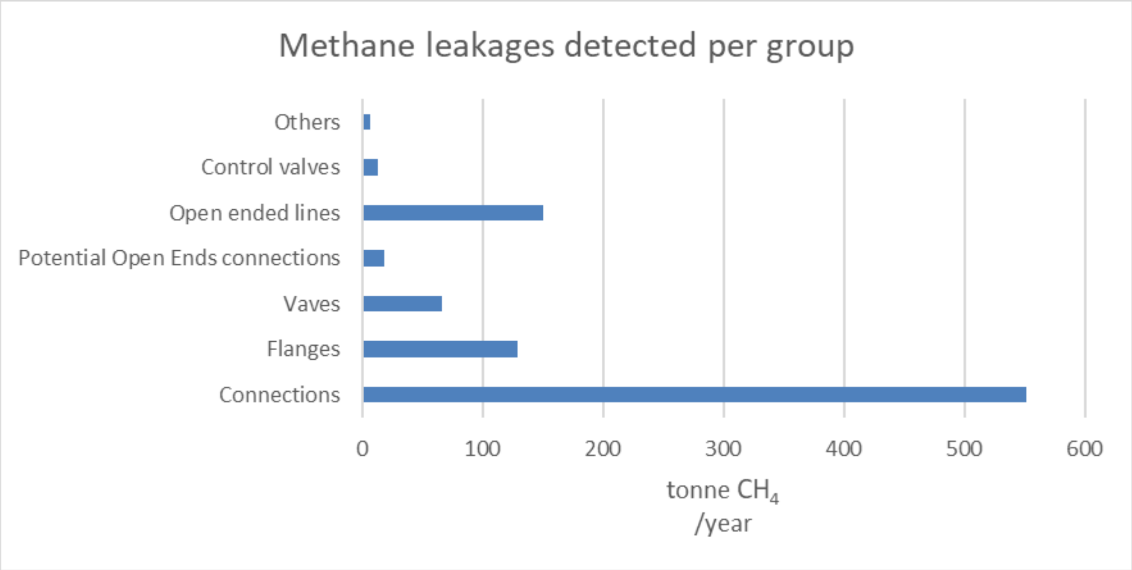


Figure 15
Methane leakages detected per group shown in Figure 14 (Bekker, 2011)



The distribution of emissions based on the shown groups was slightly different than the distribution of leakage sources (see Figure 15) (Bekker, 2011). The highest emissions were, as expected, associated with the connections. The next highest emissions were associated with open ended lines and the third highest emissions were caused by flanges.

Benefits

Economically speaking, the break-even point of implementing LDAR for large facilities like the compressor stations was found to be 2 years whereas for smaller facilities it was larger than 5 years (Bekker, 2011). Thus, it can be said that implementing LDAR can even be profitable, at least for large facilities.

By targeting the fugitive emissions from metering and regulating stations, blending stations and gas receiving stations, methane emissions up to 27 $CO_{2,\,eq}$ can be avoided.

4.1.3 Mobile recompression

Description

Mobile recompression unit is used to recompress the gas that would otherwise be vented and then transfer to a different pipeline (Gasunie, 2019). Characteristics of a mobile recompression unit should be:

1) Ability to operate on any gas within the grid
2) Being easy to transport and install
3) Ability to operate with a high-pressure ratio
4) Being explosion proof
5) Safety
6) Ability to operate without external power supply.

Technical specifications
The following technical specifications are all sourced from Rotink and Van Dijk (Rotink & Van Dijk, 2009). The recompression unit that Gasunie designed and manufactured was a semi-trailer unit and weighed 37 tonne. A two-cylinder reciprocating compressor from Dresser was designed and was powered by a shaft operating on a 12-cylinder V-engine using the process gas and delivering a maximum power output of 225 kW. By using the process gas, the unit becomes a completely independent unit with a 60 kVA diesel generator supplying the required electricity.

The compressor is able to operate in series or parallel mode by using both the cylinders parallelly or by using one cylinder to take gas from the suction line and compressing it into the second cylinder, which is connected to the discharge line. When the pressure in the suction line reaches 6-10 bar, suction automatically stops. When the pressure in the suction line reaches 22 bar, the compressor automatically switches to serial mode. The discharge cooler wools down the gas in the discharge line to a temperature suitable for the grid.

Benefits
A practical example as explained by Rotink et al. (2009) states that, if a pipeline section 36” in diameter and 10 km long is to be recompressed, it would take the unit 66 hours to decrease the pressure in the pipeline to the required 10 bars. It would take 2 days to connect and disconnect the unit from the pipeline. During this process, the unit would have retrieved a volume of 360,000 Nm^3 NG and consumed 3,600 Nm^3 for its operations. This suggests the estimated fuel consumption is approximately 1% of the total gas retrieved.

In 2020, recompression was able to return approximately 597,000 Nm^3 NG back to the grid (Gasunie, 2019). By targeting the venting emissions, methane emissions up to approximately 39.2 kt $CO_{2,\,eq}$ can be avoided.

Economic specifications
Gasunie has been operating a mobile recompression unit since 2004. The cost of building a mobile compressor as per the requirements of Gasunie was 2 million $euro_{2018}$ (Rotink & Van Dijk, 2009). The design and manufacturing of the first unit ran into some problems and resulted in some extra costs. It is expected that future units would cost much less than the first one. As a general industry rule of thumb, annual O&M costs are usually 10% of the initial investment and this is the case as observed with the mobile recompression unit (Rotink & Van Dijk, 2009).

4.1.4 Replacing emissions causing equipment
This program focuses on finding equipment responsible for emissions and replacing them with alternative equipment with lower or no emissions.

Zero-emission control valves
Zero-emission control valves can eliminate all the fugitive emissions associated with the control valves used on the Metering Stations.

Technical Specifications
Zero-emission control valves can eliminate all the fugitive emissions associated with the control valves used on the Metering Stations. Zero-emissions valves can use other alternative actuators such as an electric actuator instead of the traditional gas actuators (Saeid Mokhatab, 2009). Zero-emission control valves are already being implemented. One example is the Zero-emission control valve by Mokveld (Mokveld, 2021). Zero-emission valves are very similar in dimensions to the traditional valves and do not need any extra care during their installation.

Benefits
The valves eliminate fugitive emissions over the lifetime of the valve. The internal electric actuator gets rid of the need of dynamic seals which are the main source of leakages for the traditional valves. By reducing the leakage sources, the operation and maintenance costs required to repair the leakages are also reduced. The avoided leakages also contribute increasing the final delivery of NG resulting in higher revenues. Replacing pneumatic equipment with zero emissions or low emissions equipment has even been found to be economically beneficial with negligible associated costs (Wikkerink, 2006).

4.2 Reducing CO_2 emissions

4.2.1 Electric compressors

Description
The compressor stations (CS) operated by Gasunie use gas turbine compressors that consume NG and contribute to the CO_2 emissions. However, NAM operates electric motor driven compressors on the production clusters on Groningen and Gasunie operates electric motor driven compressors on a few compressor stations such as the Wijngaarden CS (Pijnacker Hordijk, 2012). These compressors use electricity and avoid the emissions that could have been released if they used NG instead. Avoiding the burning of NG also decreases the methane emissions associated with unburnt gas, flushing of compressors where compressors are flushed with gas before cold starting them and the leakages from seals and valves. Electric motor driven compressors can be used at compressor stations, LNG facility and at storage sites. Although, the capacity of compressors will vary based on their application.

Technical specifications
Natural gas compressors use air cooling or water-cooling systems to dissipate the heat generated during the combustion of NG. Based on the required pressure increase, either several compressor units with small capacity or a large multistage compressor can be used (Håvard Devol, 2013). When several compressor units are used, they are generally operated in parallel wherein each compressor unit handles a part of the required flow. The multiple flows are then mixed and the gas directed back into the pipeline. Thus, the required pressure and the required flow of gas decides the size and number of compressors to be used on a facility. All these factors together decide the availability, fuel consumption and capacity of the facility. For reference, the largest compressor station at Vilsteren in the municipality of Ommen consists of (6 x 11.25 MW) + (6 x 11.3 MW) + (3 x 23.9 MW) gas turbine driven compressors (Kunberger, 1978). The Wijngaarden CS operates four 10 MW electric motor driven compressors (Pijnacker Hordijk, 2012).

An electric motor compressor requires a stable and highly reliable electricity source near the compressor station. Although the onshore location of the compressor stations makes it easier to provide such an electrical source, a voltage converter is required to transform the input voltage into the required rated voltage for the electric motor driving the compressor. Modern voltage converters like the SINAMICS GL-150 also have an integrated Variable Speed Drives (VSDs) which allows for greater flexibility in operating the compressor. The Siemens SINAMICS voltage converters (also sometimes called as drives) offers a wide range of power outputs from 180 kW to 120 MW (Siemens, 2012). They have an efficiency of 99% and can reduce the energy consumption by almost 50%. The Siemens SIMOTICS motors than can be coupled with SINAMICS voltage converters offer a power output of up to 25 MW (Siemens, 2015). The motors operate at an efficiency of 95-99%, further reducing the energy consumption. The advantages of using an electric motor compressor over a gas turbine compressor are as follows:

1) Less space required.
2) Quiet operation.
3) Operation is independent of weather unlike gas compressors that are affected by temperature variations (Higher performance during cold weather and lower performance during hot weather).
4) Zero or low emissions. The emissions would be mainly dependent on the emission factor of the electricity grid.
5) Electric motor compressors are more efficient and therefore, decrease the energy consumption.
6) Due to decreased consumption of NG, there is an increase in final NG delivery.
7) Low maintenance costs.
8) Low installation costs.

Although the introduction of VSDs and electric motors add new elements to maintenance, requiring specialized staff, the maintenance of VSDs reduces to yearly checks to minor components such as air filters, in air cooled VSDs, and back-up batteries in water cooled VSDs, making maintenance costs very low (Scheuer et al., 2007).

Benefits

The CO_2 emissions factor for combustion of NG by a gas turbine is 0.20 kg CO_2eq per kWh. Assuming a 33% efficiency for gas turbines compressors, the emissions factor for a kWh output from the compressor is 0.6 kg CO_2eq per kWh. The emissions factor for electricity in the Netherlands was 0.37 kg CO_2eq per kWh in 2019. Taking into account the efficiency of voltage converter (99%) and the electric motor (95%), the emission factor for a kWh output would be 0.39 kg CO_2eq per kWh. This simple calculation shows a 0.21 kg CO_2eq per kWh emissions savings by switching to an electric motor compressor. This corresponds to a total emissions reduction of 8 kt CO_2eq from compressor stations and 41 kt CO_2eq from the entire onshore gas industry.

As all the CO_2 emissions from an electric compressor are from the electricity used, they will decrease as electricity becomes cleaner. Penetration of green electricity production technologies is expected to increase such that 70% of the electricity production is renewable by 2030 and entirely emission-free by 2050 (Dutch Government, 2019). Accordingly, a grid emission factor for 2030 of 0.09 kg CO_2eq per kWh is expected (PBL, 2021). This would result in a CO_2 emissions reduction from using electric compressors of almost 100 kt CO_2eq by 2030.

The emissions factor for methane emissions for a gas turbine assuming a 33% efficiency would be 0.04 g CH_4 per kWh or 1 g CO_2eq per kWh of output (Steller, 2018). Even though negligible compared to the emissions from NG combustion, they would be completely eliminated with the switch to electric motor compressors. This would correspond to a methane emissions reduction of 1.2 kt CH_4 or 34 kt CO_2eq.

Economic specifications

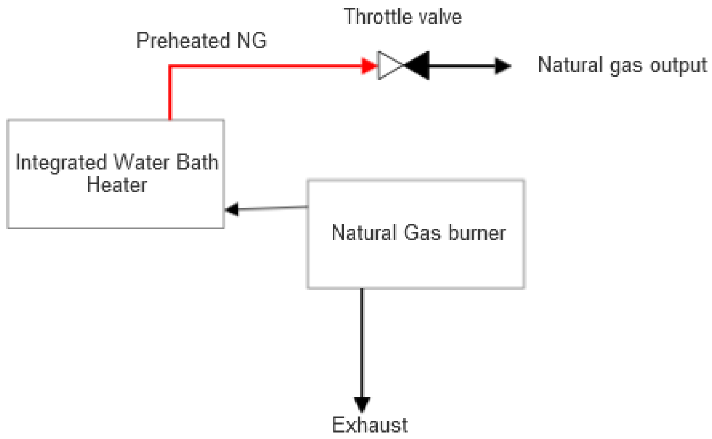
The cost of installing four 1.3 MW electric compressors in the USA was reported to be US $9.4 million$_{2018}$ in 2011 (EPA, 2011). The installation costs of an electric drive for a reciprocating compressor were reported to be about 50-60% less than that of an equivalent natural gas engine driven motor (Kolwey, 2020). The annual O&M costs of the electric motor driven compressors is expected to be 10% of the capital costs (EPA, 2011). It is also suggested that the costs of replacing natural gas engine driven motors with electric motors is cheaper than employing any emissions controls for natural gas driven motors (Kolwey, 2020). It is however important to note that most natural gas engine driven motor compressors in the USA are used at gathering and boosting stations in the mid-stream segment of distribution grid.

The capacities of compressors at larger stations such as the Wijngaarden CS in the Netherlands have large compressor capacities. Wijngaarden CS operates four 10 MW electric motor driven compressors (Pijnacker Hordijk, 2012). As part of the Groningen Long Term project, two 23 MW electric compressors were installed at 16 production clusters on the Groningen field. The totals costs for the first cluster were reported to be approximately US $70 million$_{2018}$. If the costs reported by EPA are assumed to have a linear relation with the capacity of the compressor, two 23 MW compressors would cost approximately US $80 million$_{2018}$. However, the linear relation may not hold; the costs for constructing one 23 MW compressor is likely significantly lower than constructing eighteen 1.3 MW compressors.

4.2.2 Options for gas fired boilers at Gas Receiving Station

The Regional Transmission Line meets the local distribution grid at the Gas Receiving Stations. One of the important tasks carried out at the GRS is to reduce the pressure of NG in the pipeline from 40 bar to 8 bar. This is achieved through isenthalpic throttling of natural gas by an expansion valve. During the adiabatic expansion, there is a simultaneous decrease in temperature. To avoid the formation of gas hydrates and clogging up the expansion valve, the gas is preheated by using a heating device. The most common heating device is an Indirect Water Bath Heater which consists of a gas boiler and a tube heat exchanger (see Figure 16) (Farzaneh-Gord et al., 2014). The system requires low temperature heat and the burner usually consumes the gas on the lower pressure end of the valve.

Figure 16
The Indirect Water Bath Heater (IWBH) schematic diagram (Farzaneh-Gord et al., 2014)



A mathematical model for calculating the capacity of a preheater can be found in Appendix 1.

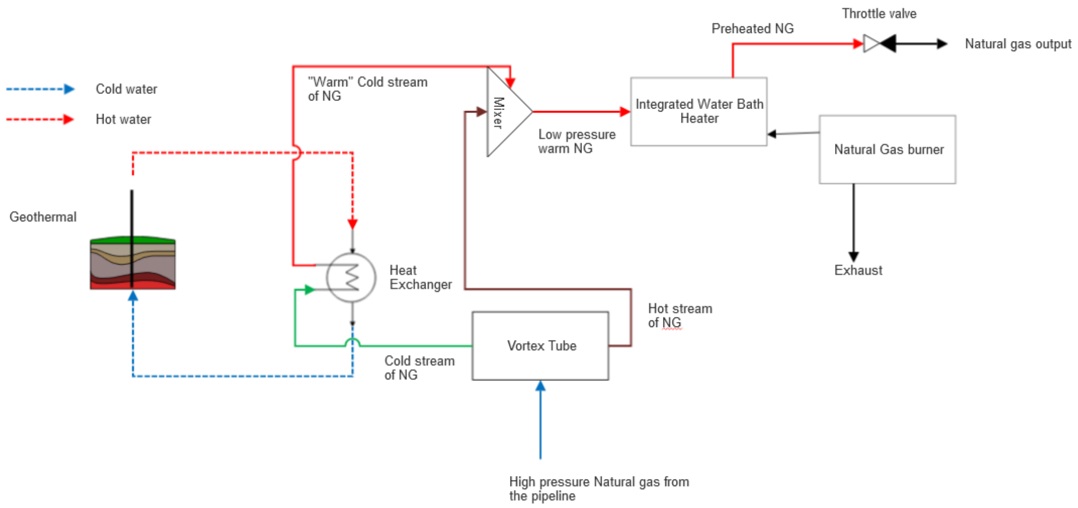
The purpose of the preheating device is to elevate the temperature of the high-pressure gas such that the temperature of the expanding gas will not reach dew point temperature of 276.15 K. The temperature decrease of the natural gas can usually be assumed to be about 0.4 K/bar (Balazs et al., 1994). Multiple ways of increasing the efficiency of the preheating process have been discussed in literature.

There are alternative ways to heat the NG without burning the NG, producing CO_2 emissions. Two types are listed above. One alternative based on solar thermal heat is addressed in detail in Appendix 3.

Electric boiler or electric heat pump
Electricity-driven heat production requires a local connection to electricity grid of sufficient capacity. For a fully decarbonized heat source, CO_2-free electricity is needed. Electric boilers and heat pumps and their techno-economic parameters are well-known replace described in detail in other MIDDEN reports, for instance by Mooij and Muller (2021).Vertical Ground Coupled Heat Exchanger with Vortex Tube

Description
Ghezelbash et al. (2016) propose a design with vortex tubes coupled with vertical geothermal heating to reduce the pressure ratio and preheat the natural gas before it enters the conventional water bath heater (Ghezelbash et al., 2016). Vortex tube is a mechanical device which separates a high-pressure stream of gas into hot and cold streams, in the process reducing its pressure. It is also known as Ranque-Hilsch Vortex Tube (RHVT). The study was conducted for a pressure reduction station in Iran. The schematic of the proposed system is shown in Figure 17.

Figure 17
The proposed vertical ground coupled heat exchanger with vortex tube schematic diagram (Ghezelbash et al., 2016).



Technical Analysis
The design proposed by Ghezelbash et al. (2016) uses a vortex tube to first reduce the pressure of high-pressure natural gas and separate it into a hot-stream and a cold-stream. The cold stream is allowed to flow through a vertical ground coupled heat exchanger (VGHX). The vertical ground coupled heat exchanger uses geothermal energy to provide heat for the cold-stream coming out of the vortex tube. For this study, two configurations of VGHX are used: (1) 25 bore holes in a square pattern, and (2) 16 boreholes in a L pattern. Each borehole has a diameter of 15 cm and is 100 m deep. The warm cold-stream is then mixed with the hot-stream coming out of vortex tube. The new mixture with a higher temperature and lower pressure than the vortex tube natural gas input stream is then transferred into a conventional water bath powered by a gas burner. Due to lower pressure reduction required from the throttle valve and coupled with a higher temperature, there is a reduction in the required pre-heating from the water bath. This decreases the fuel consumption by the gas burner.

It is important to make sure that just like in the throttle valve, the temperature of cold-stream out of the vortex tube is not below the dew point temperature of natural gas to avoid hydrate formation. The outlet temperature of the hot-stream and the cold-stream depend on the cold mass fraction of vortex tubes.

The cold mass fraction is defined as the ratio of the mass flow rate of cold-stream to the mass flow rate of the hot-stream and is given by:

$$\mu_c = \frac{\Delta T_{hot}}{\Delta T_{hot} + \Delta T_{cold}} \qquad (7)$$

ΔT_{hot} = Temperature difference between the inlet stream and the hot-stream.
ΔT_{cold} = Temperature difference between the inlet stream and cold-stream.

For the study, Ghezelbash et al. (2016) chose a cold mass fraction of 0.8 and the inlet gas temperature and pressure to the vortex tube was 283.15 K and 69 bar. The separated cold-stream and hot-stream have the same pressure of 23 bar but their temperatures are 277.15 K and 304.35 K respectively. After the cold-stream enters the shell and tube heat exchanger and receives heat collected from the VGHX, its exit temperature reaches up to 278.55 – 282.15 K. The required inlet temperature at the inlet of throttle valve for the given inlet pressure was calculated to be 291.05 K (much lower than the generally required temperature of 313.15 – 328.15 K for conventional systems). As a result, the required water bath temperature inside the pre-heater also decreases dramatically.

Benefits
The simulation showed huge decrease in the gas consumption of the pressure reduction station. For the conditions given above, a decrease of 80-88% energy consumption was calculated. This would suggest that emissions in the range of 43-47 kt CO_2 can be avoided.

Economic Analysis
Vortex tubes are very cheap compared to the costs of drilling the bore holes for VGHX. Drilling borehole costs in the Netherlands are expected to be €$_{2020}$ 65 per meter (Badenes et al., 2020). Ghezelbash et al. shows that it is possible to achieve a discounted pay-back period of less than 10 years.

In the context of Netherlands
Compared to solar thermal systems, VGHX can be used throughout the year without significant variations. Moreover, unlike air sourced heat pumps, the COP of VGHX does not depend on ambient temperature. This makes VGHX more reliable than any other renewable source of energy. However, the capital costs associated with it are higher. In addition, vortex tubes also do not require external energy to operate. All in all, VGHX with vortex tubes are highly reliable, can work throughout the year, can provide enough flexibility during peak demand and are highly profitable.

4.2.3 Options for steam production at CHP

The steam production used for the oil extraction could alternatively be produced with electric boilers (or electric heat pumps), which is free of greenhouse gas emissions when the electricity is generated using CO_2-emission free sources. Alternatively, hydrogen could be used instead of natural gas. Using electricity or hydrogen as fuel is only possible if sufficient amounts could be supplied locally. Techno-economic properties of these options are described in other MIDDEN reports, for instance by Mooij and Muller (2021).

The benefits of replacing the present steam production by alternative steam production methods depend also on the future plans for the oil production site. The longer the site will remain in operation, the more cost-effective will the replacement be.

4.3 Summary of decarbonisation options

Table 10 categorises and summarizes the options that have been discussed above.

Table 10
Summary of decarbonization options discussed in this report.

Decarbonization option	Decarbonization Category	Emissions targeted	Facilities	Potential emissions Reduction
Mobile Flaring*	Flaring	Methane (Venting)	Pipeline	Methane: up to 35 kt $CO_{2,eq}$
Leak Detection and Repair*	Detection and repair	Methane (Leakage)	Pipeline and all facilities	Methane: up to 27 kt $CO_{2,eq}$
Mobile Recompression*	Recompression	Methane (Venting)	Pipeline and facilities under maintenance	Methane: up to 39 kt $CO_{2,eq}$
Zero Emissions Equipment*	New equipment	Methane (Leakage)	All the facilities	Methane: up to 27 kt $CO_{2,eq}$
Electric Compressors	Electrification	Methane and CO_2 (venting, leakages and combustion)	Compressor Stations Storage sites LNG facility	CO_2: up to 100 kt CO_2 (2030) Methane: up to 34 kt $CO_{2,eq}$
Electric heat production**	Electrification	Methane and CO_2 (Leakages and combustion)	Gas Receiving Station	CO_2: at least 53 kt CO_2
VGHX with vortex tubes**	Integrating renewables & excess energy recovery	Methane and CO_2 (Leakages and combustion)	Gas Receiving Station	CO_2: at least 43 – 47 kt CO_2
Alternative steam production	Electrification / fuel switch	CO_2 (combustion in CHP)	Oil production	CO_2: up to 165 kt CO_2

*;** Targets the same emissions

4.4 Alternatives to NG in the network

In order to assess the decarbonisation options of the onshore NG industry, it is necessary to understand the cleaner alternatives that are most expected to replace natural gas in the network. The options discussed are hydrogen and green gas. Hydrogen can be further classified into green hydrogen (produced by electrolysis of water) and blue hydrogen (produced from natural gas while capturing and storing the emitted CO_2).

4.4.1 Hydrogen

Hydrogen is a cleaner substitute to NG as the only byproduct of burning hydrogen is steam. Additionally, the costs of hydrogen transportation over long distances are cheaper than the price of electricity cables (Miao et al., 2021). However, to replace NG with hydrogen, the current gas grid would have to undergo significant modifications (Hydrogen Council, 2020). The capex for new hydrogen pipelines can be about 110-150% of those for a new natural gas pipeline (Siemens Energy, Gascade Gastransport GmbH, 2020). However, if the existing grid is repurposed, the capex for modifications are expected to be 10-35% of that of new hydrogen pipelines (ACER, 2021). A Navigant study (2019) estimates the cost of repurposing existing gas pipelines at €3.7 per MWh for 600 km (Navigant, 2019). The total costs for refurbishing the Dutch distribution networks for distribution of hydrogen are estimated at €700 million (ACER, 2021). The levelised cost of hydrogen transportation by pipeline is estimated to be between €0.09 - €0.17 per kg H2 for 1000 km (ACER, 2021). According to the European Hydrogen Backbone project, a coalition of international gas providers throughout the EU and UK, 69% of the gas grid can be repurposed to transport hydrogen instead.

As mentioned earlier, hydrogen can be classified into green hydrogen and blue hydrogen.

Green Hydrogen

Hydrogen that is generated from renewable energy is called green hydrogen. The most common method (which is often referred to as the definition of green hydrogen) is to use electricity generated from renewable technologies for electrolyzing water and separating the hydrogen. Electrolysis is a well-established technology where water is split into hydrogen and oxygen. However, electrolysis is still expensive and relatively inefficient. The amount of renewable electricity required to generate enough hydrogen through electrolysis for replacing NG entirely is also not currently available.

Blue Hydrogen

Hydrogen that is generated through steam methane reforming (SMR) by using methane or NG as feedstock along with carbon capture and storage (CCS) (to capture the carbon dioxide formed as a byproduct of the reaction) is called blue hydrogen (see also the MIDDEN report 'Decarbonisation options for the Dutch industrial gases production' by Cioli et al. (2021)). According to IEA, around 96% of hydrogen created worldwide is derived from fossil fuels (IEA, 2021). This process involves mixing steam with fossil fuels and heating it to get hydrogen and carbon dioxide as products. Currently, the carbon dioxide produced is released into the atmosphere directly. However, if it were captured and stored underground or used elsewhere, the carbon footprint of the process is significantly lower. The extent to which the carbon footprint is reduced depends on the carbon capture efficiency. For assessing the total climate footprint of the use of blue hydrogen, also CO_2

and methane emissions associated with the natural gas extraction and transport should be taken into account (see Appendix 2).

4.4.2 Green gas

Green gas is derived from organic waste like animal manure and sewage sludge or from lignocellulose such as woody biomass. Generally, anaerobic digestion and gasification methods are used to turn the waste to biogas. The biogas can then be upgraded to the grade of NG. According to the climate agreement, around 2 billion m^3 green gas should be introduced into the Netherlands gas network by 2030 (Dutch Government, 2019). However, this is still a small amount in comparison to the total natural gas demand which is projected to be 26-28 billion m^3 in 2030 (PBL, 2021).

5 Discussion

The Netherlands is shutting down gas extraction from the Groningen field due to the impact of increased seismic activity. As a result, the CO_2 emissions associated with onshore extraction will also decrease and cease to exist as the production decreases. Moreover, NAM is being split and sold off as the Groningen field shuts down in 2022/2023 (DutchNews, 2021). In addition, the small fields, both onshore and offshore, owned by NAM are being sold off. Nevertheless, the CO_2 as well as methane emissions from the onshore extraction are much lower compared to offshore extraction. This can be attributed to multiple reasons, such as proximity to onshore distribution grid and compressor stations, use of electric motor compressors and higher degree of electrification for day-to-day operations. From the perspective of onshore gas industry, methane emissions play a larger role in the total emissions compared to CO_2 emissions (Yacovitch et al., 2018). The methane emissions associated with onshore gas extraction are reported annually and published by RIVM. These emissions are calculated by using the emissions factors of processes and instruments and the energy flows for each of them. However, a study by Yacovitch et al. (2018) suggests that the methane emissions associated with onshore extraction are underestimated and could likely be as much as 10 times higher than the currently reported numbers (Yacovitch et al., 2018). The methane leakages from closed production wells would also make sure that even after the production is shut down, they will continue contributing to emissions. This further highlights the importance of looking into available options to reduce methane emissions that are investigated in this study.

The Dutch government has employed strict regulations for controlling the methane emissions through venting which has resulted in a significant decrease in methane emissions, reducing the overall carbon footprint of natural gas (Herber & De Jager, 2010). The Dutch natural gas boasts an extremely low life-cycle carbon footprint compared to the world average (approximately 60% less than global average) (Beckman & Van den Beukel, 2019).

Speaking of gas transport, due to government regulations and Gasunie's own initiatives, most of the "low-hanging fruits" measures to reduce emissions have already been considered and employed by Gasunie (Gasunie, 2019). Again, the small carbon-footprint of Dutch natural gas is a testament to these efforts. To reduce the emissions further, Gasunie would have to start considering innovative measures and undertake radical changes in their operations and infrastructure. Such drastic measures are expected to come with high capital costs. The attractiveness of the investments for these innovative solutions will depend highly on the following factors:

a. Carbon pricing: A higher carbon price would encourage companies to invest in technologies with lower costs of avoiding emissions. Economic savings associated with avoided carbon pricing could help reduce the pay-back period of new technologies, making them more attractive investment options.
b. Natural gas price: High gas prices would result in higher economic gains due to increased delivery of end products. Higher economic gains can lead to better motivation to invest in new technologies with optimistic estimations for pay-back periods. However, lower gas prices would discourage investment in new technologies due to lower expected economic gains for fuel savings.

However, for Gasunie, the saved costs from fuel savings are likely to be negligible considering Gasunie does not own the gas it transports. Therefore, cooperation between Gasunie and gas owners can make investment into such technologies more attractive. Moreover, the technological options for reducing the fuel consumption of gas receiving stations that are discussed in this study have not been verified in the Dutch context. It is necessary to further look into the feasibilities of implementing these technologies in the Netherlands by performing feasibility studies on specific gas receiving stations in the Netherlands.

Finally, the availability of data to the public is extremely limited. Due to a lack of publicly available information, the study had to consider extremely old sources to set the worst-case scenario benchmarks. Another surprising point to note would be the absence of any public, latest and up-to-date decarbonisation studies for the onshore gas industry in the Netherlands. Even though the industry has a small carbon footprint compared to its international counterparts, most of the decrease in emissions in recent times can be attributed directly to a decrease in domestic production activity. It must reduce its emissions even further by implementing innovative and concrete solutions to help limit the consequences of climate change. The industry has a chance to take lead in supporting the efforts against climate change and turn around the societal perception towards it.

To conclude, the Dutch government has been taking strict actions and formulating policies to reduce emissions associated with the energy industry in the Netherlands. The companies involved in the onshore industry have already been taking small steps to avoid emissions and will have to start investing into more innovative solutions. Cooperation between companies and the government, feasibility studies into innovative solutions, increased natural gas prices and carbon pricing can influence the attractiveness towards and implementation of decarbonization solutions and achieve a successful energy transition.

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Appendices

Appendix 1

Englart et al. (2019) propose a simplified mathematical model to calculate the capacity of preheater (Englart et al., 2019).

The gas density is given by:

$$\rho_n = d \times \rho_p \tag{2}$$

ρ_n = Gas Density
d = relative gas density
ρ_p = air density at T=273.15 K = 1.293 kg/m3

The gas temperature increase is given by:

$$\Delta T_1 = T_{out} - T_{in}^{min} \tag{3}$$

T_{in}^{min} = minimum input gas temperature
T_{out} = output gas temperature

The impact of Joule Thomson effect on the temperature due to expansion is given by:

$$\Delta T_2 = (P_{in} - P_{out}) \times \Delta T_1 \tag{4}$$

ΔT_2 = Joule Thomson effect on temperature of the gas after expansion
P_{in} = input gas pressure
P_{out} = output gas pressure

The total change in temperature:

$$\Delta T_g = \Delta T_1 + \Delta T_2 \tag{5}$$

ΔT_g = required gas temperature increase before pressure reduction

The heating capacity of the preheater is calculated as:

$$W = (Q \times \Delta T_g \times \rho_n \times C_p)/(\eta \times 3600) \tag{6}$$

Q = flow capacity in m³/hr
C_p = specific heat of gas at 273.15 K and 1 bar = 1900 J/(kgK) (Gasunie, 1980)
η = efficiency of gas preheater

Appendix 2 Climate footprint of blue hydrogen

Production of hydrogen from fossil fuels, especially from NG, is a mature technology that is being implemented worldwide. Most common technology used is Steam Methane Reforming (SMR). Installing carbon capture plants alongside these plants and producing blue hydrogen is technically feasible and can be relatively easily replicated (provided that carbon storage infrastructure is available nearby). Green hydrogen produced by electrolysis is currently operating at a much smaller scale globally.

There is a debate about the impact of blue hydrogen on the climate. Blue hydrogen is largely considered to substantially reduce the emissions compared to fossil fuels (Di Lullo et al., 2021), (Edwing et al., 2020). However, some studies suggest that using blue hydrogen a an energy carrier will not reduce the emissions substantially and in some cases, be even worse than using NG directly (Howarth & Jacobson, 2021).

The varying opinions in the debate are mainly due to the different assumptions for the following factors in the value chain of blue hydrogen:

1) CO_2 emissions associated with NG used for SMR
2) CH_4 emissions associated with NG used for SMR
3) The carbon capture efficiency of carbon capture systems (CCS)

The total emissions for NG (CO_2 and CH_4) are highly dependent on the process and equipment being used and vary for each source country. The Netherlands boasts the smallest carbon footprint in the world for the NG produced in the country. However, going forward, imported NG will play a bigger role in meeting the primary energy demand in the Netherlands. Therefore, the Netherlands has two options to produce blue hydrogen; from its own NG or from imported NG.

Here, we directly compare climate footprints of different sets of assumptions. In particular, comparing SMR with NG with low and high climate footprints, and with low and high capture and storage rates.

Low emissions

For the low emissions case, we use the CO_2 emissions of Dutch NG extraction. We use the fact that according to the energy balance for The Netherlands, the gas extraction installations (onshore and offshore) consumed 21.8 PJ NG in 2019 to produce 1,034 PJ NG. By using the LHV of NG as 35.17 MJ/Nm^3 and a NG combustion emissions factor of 56.6 gCO_2/MJ_{NG}, around 1.2 gCO_2 was emitted for every MJ of NG.

As the large-scale blue hydrogen plants will be connected directly to the transportation grid, we only need to consider the methane losses from NG production and high-pressure transport. The study considers 0.4% (based on methane emissions calculated earlier) losses in methane emissions for the same, which is 0.08 gCH_4/MJ_{NG}. However, there is a possibility of underestimation of methane emissions from gas production and compressor stations in the Groningen area (Yacovitch et al., 2018). The extra emissions result in a leakage rate of approximately 1%, instead of 0.4%. The methane emissions for a 1% leakage rate would be 0.2 gCH_4/MJ_{NG}. The majority of the increase in methane emissions would be from NG production and processing activities. Here, we use the official number of 0.4% leakage.

High emissions

For the high emissions scenarios, we assume CO_2 emissions of NG produced abroad and transported to The Netherlands by a 4000 km pipeline, e.g. from Russia (Thinkstep, 2017). Furthermore, we assume methane emissions of 1.7%, corresponding to the global average methane emissions from NG production according to a recent study (Cooper et al., 2021).

Very high emissions

We have added a very high emissions scenario, in which we assume CO_2 emissions of NG produced abroad and transported to The Netherlands as LNG, e.g. from the US or Algeria (Thinkstep, 2017; NREL, 2019). CO_2 emissions of 15-24 g CO_2/MJ_{NG} can be expected, we have taken 18 as a representative example. Methane emissions can vary dramatically, we have left it at the global average according to a recent study (Cooper et al., 2021).

Carbon capture and storage rates

We use a low rate of 55% which is an estimate for precombustion capture rate for SMR (Cioli et al., 2021). The high capture rate corresponds to autothermal reforming (ATR) or to post-combustion capture at SMR (Cioli et al., 2021).

Greenhouse warming potential

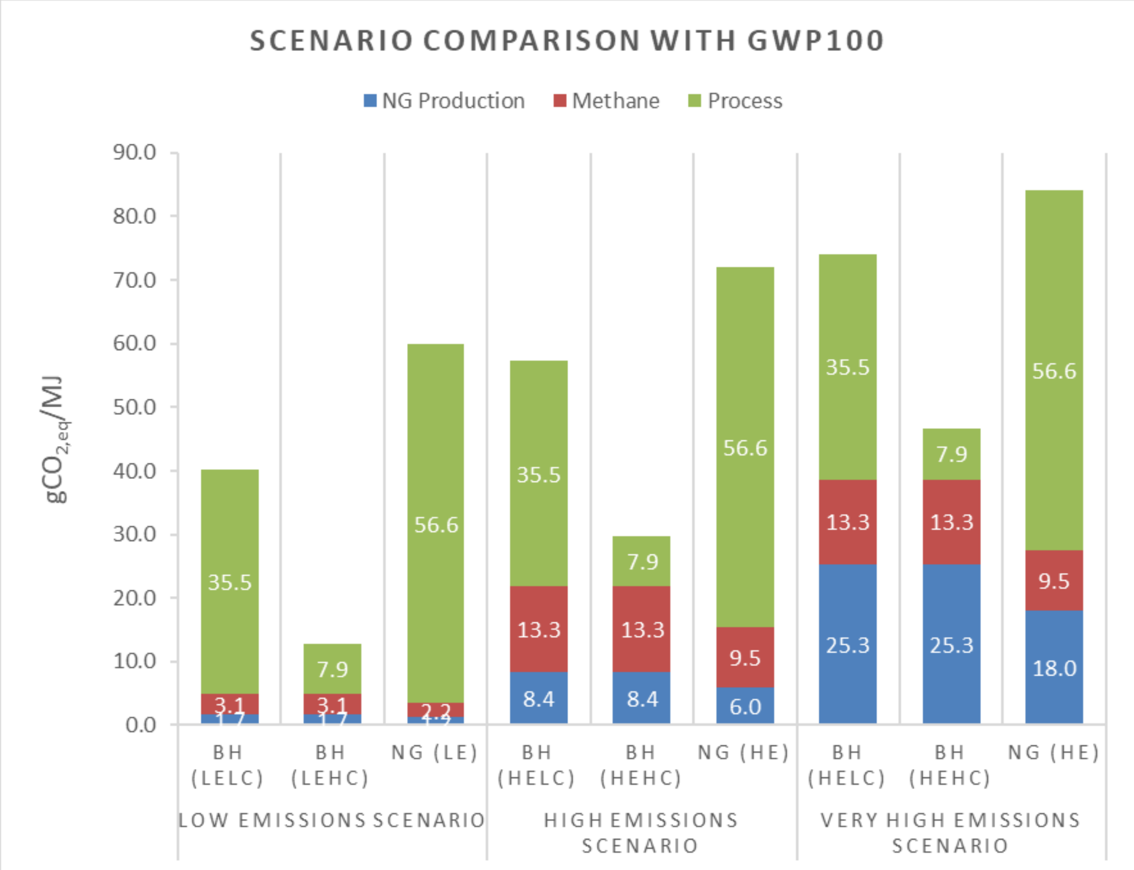
Finally, we calculate the greenhouse warming potential for methane based on a 20-year and 100-year approach, using GWP_{20}=84 and GWP_{100}=28 (IPCC, 2018). GWP_{100} is the common parameter according to IPCC standards, but considering the limited lifetime of methane in the atmosphere, it makes sense to calculate the 20-year potential as a comparison.

A summary of the cases is shown in Table 11 and the results are displayed in Figures 18 and 19.

Table 11
Comparison of blue hydrogen and natural gas emissions: different sets of assumptions.

	CO_2 emissions (gCO_2/MJ_{NG})	Methane emission rate (gCH_2/MJ_{NG})	Carbon capture and storage rate (%)
Blue hydrogen: low emissions, low capture rate (LELC)	1.2	0.08 (0.4%)	55%
Blue hydrogen: low emissions, high capture rate (LEHC)	1.2	0.08 (0.4%)	90%
Natural gas: low emissions, no capture (LE)	1.2	0.08 (0.4%)	n/a
Blue hydrogen: high emissions, low capture rate (HELC)	6	0.34 (1.7%)	55%
Blue hydrogen: high emissions, high capture rate (HEHC)	6	0.34 (1.7%)	90%
Natural gas: high emissions, no capture (HE)	6	0.34 (1.7%)	n/a
Blue hydrogen: very high emissions, low capture rate (VHELC)	18	0.34 (1.7%)	55%
Blue hydrogen: very high emissions, high capture rate (VHEHC)	18	0.34 (1.7%)	90%
Natural gas: high emissions, no capture (VHE)	18	0.34 (1.7%)	n/a

Figure 18
Breakdown of total emissions for blue hydrogen (BH) production compared to natural gas; GWP_{100}

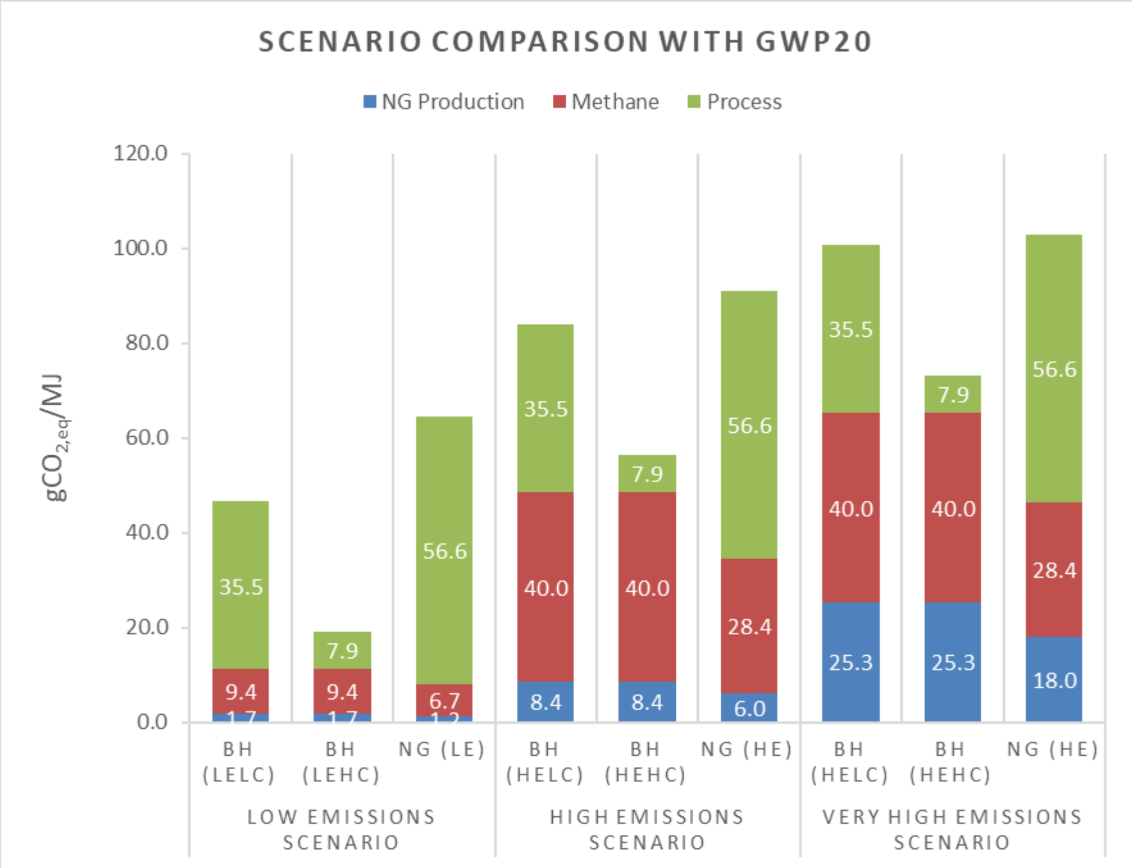


Looking at Figure 18 which considers the default GWP_{100}, it is clear that blue hydrogen in the low emissions scenario has a significantly better carbon footprint than natural gas, particularly in the high capture case which presents a ~80% improvement compared to natural gas. However, the low capture (55%) case shows a reduction of less than one third compared to natural gas.

In the high emissions case, related to imported natural gas (e.g. from Russia), the difference between blue hydrogen and natural gas becomes even smaller. Finally, in the very high emissions scenario which corresponds e.g. to LNG, the footprint of blue hydrogen with low CO_2 capture rates is worse than domestic NG. This is due to the NG production and transport emissions being dominant over the emissions related to hydrogen production.

It can be concluded that using blue hydrogen based on LNG represents almost no improvement over domestic NG, in terms of climate footprint.

Figure 19
Breakdown of total emissions for blue hydrogen production compared to natural gas; GWP_{20}



For comparison, we have also calculated the emissions based on GWP_{20}. In this case, the methane emissions are even more important. Therefore, in the high and very high emissions scenario, using hydrogen produced by SMR with pre-combustion CCS (low capture rate) is hardly an improvement over using the same natural gas directly. Furthermore, the footprint of domestic NG is better than or comparable with those of *all* forms of blue hydrogen produced from NG with globally average methane emissions (i.e. high or very high emissions).

Appendix 3

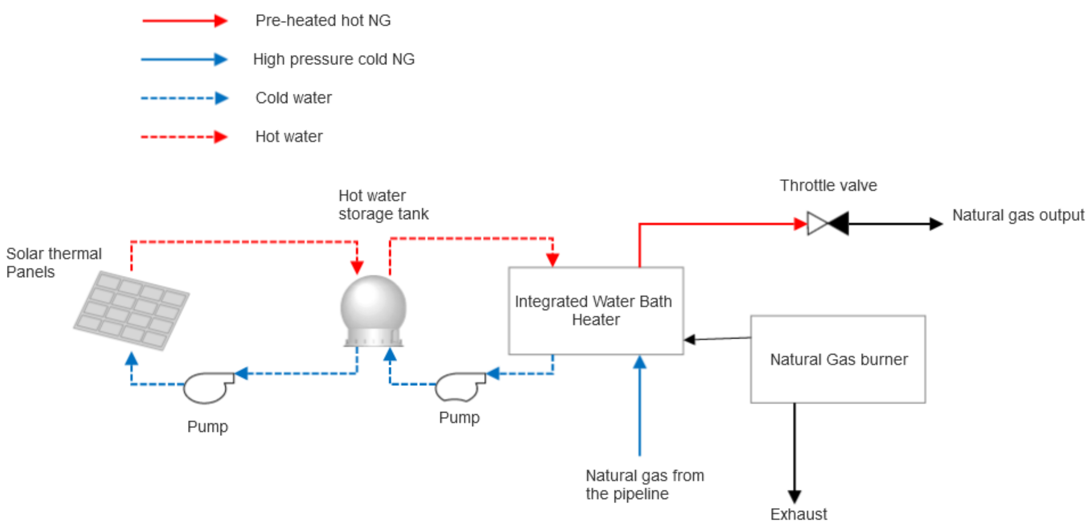
More alternatives to gas-fired boilers

Solar thermal with thermal storage

Description
Farazneh-Gord et al. (2021) proposed a solar collector array with thermal storage to provide a part of the low temperature heat required for preheating and decrease the fuel consumption of burner (Farzaneh-Gord et al., 2014). They also proposed a controllable heater that produces just enough amount of heat as needed for natural gas to approach the required output temperature. Figure 20 shows the configuration of the modified system.

Technical Analysis
Farazneh-Gord et al. (2021) also proposes a mathematical model to design a solar collector with a storage tank for a very specific pressure reduction station at Akand in northern Iran. They use a flat plate collector as temperatures below 353.15 K are required. The system is designed with an automatic control system to avoid over-heating of natural gas, which increases the overall efficiency. After carrying out a thermo-economic analysis, they propose a parallel array of 380 collectors with a plate area of 1.5 m^2 for each collector and a storage tank with 38 m^3 capacity. The collectors are placed at a slope of 48°. About 10,000 m^3/hr natural gas is expected to flow through the preheater. The output temperature of natural gas is decided as 278.15 K after a pressure drop of around 45 bar.

Figure 20
The proposed solar thermal with thermal storage model schematic diagram (Farzaneh-Gord et al., 2014).



Benefits
Farazneh-Gord et al. (2021) suggests that 8-12% of the NG consumption can be replaced by solar thermal energy. This would suggest that emissions in the range of 4.3-6.4 kt CO_2 can be avoided.

Economic Analysis
In 2014, the capital costs for such a system are mentioned to be US $\$_{2018}$ 153,000 and annual O&M costs are expected to be 10% of the capital costs. With the cost of saved fuel (assumed to be US $\$_{2018}$ 0.29 per m^3), the simple payback period would be 5.35 years and NPV was calculated to be positive after about 8 years. Inflation rate for USD was assumed to be 6%.

In the context of the Netherlands
Given that the system is designed for Iran, the solar heater will have a higher capacity factor and efficiency compared to a system that could be installed in the Netherlands. The authors expect solar irradiation of about 1,300 kWh/m^2hr (the lowest in all Iran) compared to the average solar irradiation of 1,000 kWh/m^2hr in the Netherlands. The Netherlands receives less solar irradiation and also has lower number of irradiation hours throughout the year compared to Iran. This may impact the actual heating capacity of the system and might require a bigger storage tank resulting in lower savings implying a longer payback period time.

In the context of the thermo-economic analysis performed by Farazneh-Gord et al. (2021), the analysis assumes a steady state system which is usually not the case with dynamically changing flow rates, natural gas input temperatures and incident solar irradiance. For a dynamic model, it would have to consider the higher flow rates during winter which is also the time of year when the availability of solar energy is the least in the Netherlands. This could imply lower avoided CO_2 emissions, requirement of higher thermal storage and higher number of solar collectors.

Solar thermal & thermal storage with Turbo Expanders

Description
In the previous section, we discussed the use of solar thermal systems with thermal storage to decrease the thermal demand from fossil fuels. The huge pressure drop in the natural gas pressure also presents an opportunity to use a turbo-expander (TE) and use the energy from pressure drop to generate electricity. Several studies and models have been proposed to analyze the economic and environmental benefits of using TE coupled with an electricity generator (Jelodar et al., 2013), (Andrei et al., 2014), (Barone et al., 2018), (Belousov, 2022). However, Barone et al. (2019) propose a system that uses a solar thermal system with thermal storage and coupled with a TE to further reduce the use of natural gas in the preheater (Barone et al., 2019). They performed a theoretical thermo-economic analysis in MATLAB and compared it to experimental data, finding negligible errors in the simulation. The system was specifically designed for the use case of a pressure reduction station in Messina, southern Italy.

Technical Analysis
The proposed system layout is as shown in Figure 21. The hybrid system combined a TE with a high-vacuum solar thermal collector's (STCs) field. The green line refers to the conventional pressure reduction loop with a traditional throttling valve (TV) whereas the blue line refers to the proposed pressure reduction loop with the TE coupled with the electricity generator. The auxiliary gas fired boiler is referred as the AUX, the pressurized water storage tank working as the thermal storage is referred as TNK and HSK stands for heat sink to dissipate any excess solar heat. P1 and P2 are variable speed pumps managed such that pump P1 will turn off when either the solar radiation is less than 50 W/m^2 or the outlet temperature of water from the STCs is less than the input temperature. Pump P2 supplies hot water from TNK to the heat exchanger (HE) by regulating the flow rate to avoid the formation of hydrates and optimise it so the minimum temperature required

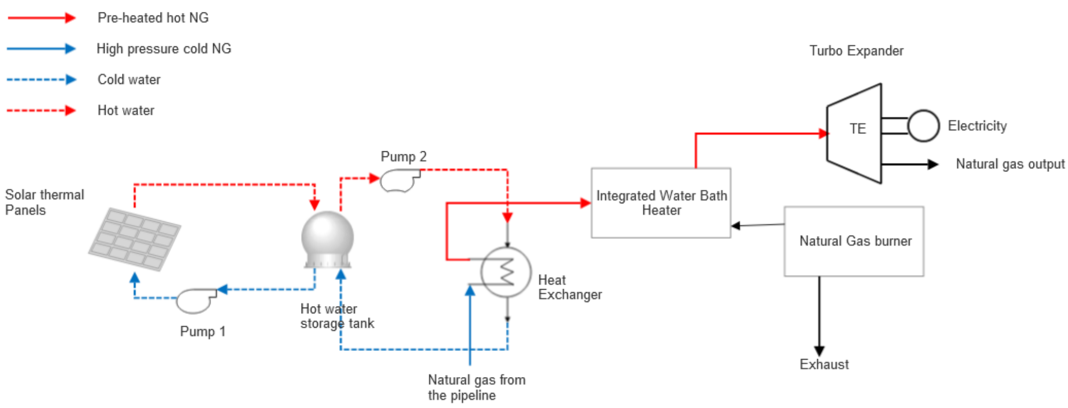
before pressure reduction is reached. The regulation of P2 minimises the use of thermal energy from AUX and maximises the use of STCs. The activation of TE for electricity generation is carried out by the three-way valve (3WV) located before the TE. The TE is used only when the NG flow rate is higher than the rated minimum flow rate of the TE. The model is dynamic and considers the input temperature of NG as given by equation 1 by assuming the average underground depth of natural gas pipeline as 3 m.

$$T_r = 0.0084 \times T_{amb}^2 + 0.3182 \times T_{amb} + 11.403 \quad (1)$$

T_r = Inlet natural gas temperature
T_{amb}=Ambient Temperature.

However, the required natural gas output temperature after TE (pressure reduction and electricity generation) is fixed at 268 K. The design parameters for the STCs can be found in detail in their paper (Barone et al., 2019).

Figure 21
The proposed model with solar thermal and thermal storage with turbo expander (Barone et al., 2019).



The authors consider the MTG-550 radial turbine with vane adjustment model for TE. Its technical parameters are as shown in Table 7. The manufacturers of the TE provided the authors with a data sheet corresponding to the required input temperature to the TE for achieving the desired TE output temperature. The TE was analysed dynamically from 30% to 100% of the maximum allowed flow rate. The hourly weather for Messina was used from the local weather station.

Table 7
Technical parameters of the MTG 550 turboexpander.

Parameter	Units	Value
Dimensions (l x w x h)	mm	1,800 x 1,800 x 1,500
Weight	kg	2,750
Minimum allowed flow rate (V_{min})	Sm^3/h	4,500
Maximum allowed flow rate (V_{max})	Sm^3/h	23,500
Inlet Pressure	Bar	24-80
Outlet Pressure	Bar	4.6-20
Net Electricity Produced	kW_e	550
Nominal Voltage	V	400
Efficiency	%	~96
Nominal Speed	rpm	32,000

A heat exchanger that optimally transfers heat between two liquids in different phases with a heat transfer surface area of 100 m^2 and a U-value of 250 W/m^2K was selected. Solar panels called MT Power were selected. Each panel has a surface area of 1.84 m^2 and a total array of 50 panels is placed at an angle of 48°. Hot water storage tank with a capacity of 4,600 litres and a pump with nominal flow rate of 0.3145 kg/s was considered.

For the traditional heating unit, a gas fired heater with nominal power of 900 kW and a thermal efficiency of 92% was considered. The maximum NG preheating temperature is set at 78°c.

Benefits

Barone et al. (2019) suggest that 8-15% of the NG consumption can be replaced by solar thermal energy. This would suggest that emissions in the range of 4.3-8.1 kt CO_2 can be avoided.

Economic Analysis

The economic and environmental analysis is shown in Table 8 (Barone et al., 2019). The simple pay-back period calculation does not include the economic gains due to avoided emissions. If these gains were considered, it decreased the pay-back period slightly to 4.35 years. The model also calculates a total electricity generation of 1,154 MWh/year. The 50 solar collectors replace about 10.6% (109 MWh/year) of the natural gas consumption.

Table 8
Economic and environmental parameters of the solar thermal with storage and turboexpander model.

Component/Parameter	Units	Value
Turbo-expander	k€$_{2019}$	1,250
Solar thermal collectors	k€$_{2019}$	32.2
Heat storage tank	k€$_{2019}$	3.64
Heat exchanger	k€$_{2019}$	16.5
Simple Pay-back period	year	4.5
Avoided CO_2 emissions	tCO_2/year	348

In the context of the Netherlands

Messina, Italy experiences more incident solar irradiation compared to Netherlands. The Netherlands also has lower number of irradiation hours throughout the year compared to Messina, Italy. This may impact the actual heating capacity of the system and might require a bigger storage tank resulting in lower savings and implying a longer payback period time.

Moreover, since the model is dynamic, it would have to consider the higher flow rates during winter which is also the time of year when the availability of solar energy is the least in the Netherlands. This could imply lower avoided CO_2 emissions, requirement of higher thermal storage and higher number of solar collectors.