HCSS Geo-economics

The deteriorating outlook for Dutch small natural gas fields

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Abstract

During the 1970's the Dutch government implemented a policy to stimulate the production of small natural gas fields. This policy has been very successful: from about 1985 until 2010 production from numerous small fields exceeded that of the giant Groningen field. Small field production peaked around the year 2000, after which a gradual decline set in. Initially, this decline was primarily due to geology: the larger fields that were found in the early phases saw a significant decline of their production and new discoveries were of a smaller size.

From about 2010 onwards, however, other factors came into play that resulted in a deteriorating investment climate for the Dutch gas industry. Earthquakes in the giant Groningen field and the emergence of climate change as a key issue in Dutch society changed the public image of gas. Non-Governmental organisations (NGOs) have been successful to picture the reduction of Dutch gas production as a relatively easy and achievable way to fight climate change. Political support for tax measures needed to stimulate the development of fields of ever decreasing size dwindled. New regulatory measures resulted in a large increase of the time needed to drill a well or to develop an exploration discovery. Recently, gas prices have fallen to relatively low levels and competition from liquefied natural gas (LNG) is increasing.

Exploration activity to find new offshore fields is now at about 20% of that in 2012, whereas estimates of the remaining exploration potential have remained at a relatively constant level. Exploration for new onshore fields is about to come to a virtual standstill. That the natural production decline of the existing fields is only offset by exploration activity to a very limited extent is primarily due to a deteriorating investment climate.

A recent lookback study by EBN, the Dutch state entity that is a non-operating partner in all Dutch oil and gas developments, indicated that over the last decade technical predictions of future production from the small Dutch gas fields had consistently overestimated production. Apparently, Dutch gas producers were no longer able to make full use of the available geological opportunities. The recent decrease in gas prices and optimistic estimates of production from existing fields have also played a role.

In all likelihood, the current poor investment climate for the Dutch gas industry is there to stay. Our mid case expectation for Dutch gas production in 2030 is thus about 5 BcM per year; in line with a forecast by EBN that fully takes into account the track record of Dutch gas producers in delivering projects over the 2010-2019 period. This is considerably lower than the official expectation from Dutch government entities which still stands at 10-12 BcM. We consider this forecast, based on an

inventory of exploration and development opportunities without a calibration to the recent track record of Dutch gas producers, to be a high case.

If anything, things are more likely to get worse rather than better. It is becoming more difficult for Dutch subsidiaries to obtain funding from international head offices. A temporary stop of many Dutch oil and gas projects during the second half of 2019, related to a reduction of the maximum acceptable levels of Dutch nitrogen oxides emissions, has further shaken the already low confidence that gas producers have in the Netherlands. Decreasing production results in higher unit operating costs for the remaining fields – potentially leading to the shutdown of all fields dependent on a certain offshore pipeline system. In our low case forecast, Dutch gas production in 2030 is about to cease completely. This scenario becomes more likely if natural gas prices stay at the current low levels for an extensive period of time.

Gas consumption in NW Europe is now relatively stable (with gas losing market share to renewables and gaining market share from coal and nuclear). Since 2014, the decrease in Dutch gas production has been mostly compensated by an increase of gas imports from Russia. In 2019, the import of LNG picked up significantly. Due to methane leakage and the energy required to transport gas over large distances, the worldwide carbon footprint of these imported gases is significantly higher compared to locally produced gas. On a global scale this currently negates all progress that is being made by increasing the share of solar and wind in the Dutch power mix. Reducing natural gas consumption, and the emission of greenhouse gases, by replacing natural gas with renewables makes sense in the fight against climate change. Reducing local gas production, in a country with low methane emissions, does not.

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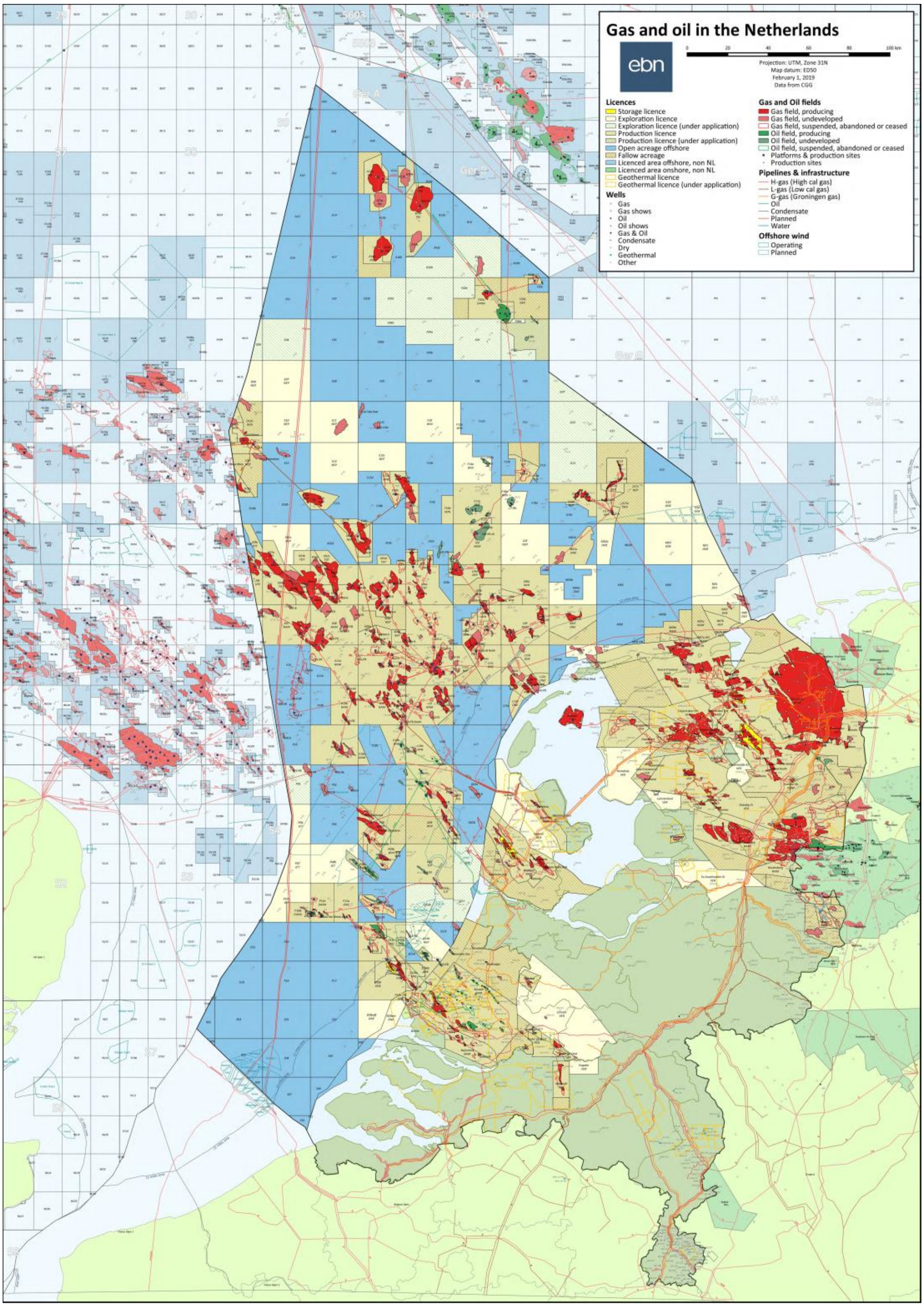


Source: [EBN - A Sea of Opportunity - Exploration in The Netherlands]

Introduction

The forecasts for Dutch gas production from small fields (that is all fields apart from Groningen) that are currently used by the Dutch ministry for economic affairs and climate to show a relatively gentle decline and still have a 2030 production of about 10-12 billion cubic meters (BcM). How realistic are these forecasts, given that small fields production has decreased significantly over the last decade and the view of Dutch society on natural gas production has dramatically changed due to earthquakes in the giant Groningen field and climate change? That is the key question that we want to address in this paper.

Groningen gas is often the first thing that comes to mind when considering Dutch gas production. Since 1980, the production from the numerous Dutch small fields has, however, been of similar magnitude as the production from the giant Groningen gas field (fig. 1).

Earthquakes at the Groningen gas field have gradually increased since 1990 and this has been a key factor in the loss of the social license to produce Groningen gas, especially after the 2012 Huizinge earthquake, and the Dutch government gradually reducing Groningen gas production since 2014. Cessation of Groningen gas production is expected in 2022.

Production from Dutch small fields, both onshore and offshore, took off in the late 1970's, following a revision of Dutch gas policy. Previously, the Groningen gas field had been ramped up to a relatively high annual production level of about 80 BcM. Following the 1973 first oil shock and the realisation that the future of nuclear energy was not as bright as expected initially, a greater emphasis was placed on security of supply and a more gradual production of Dutch gas reserves.

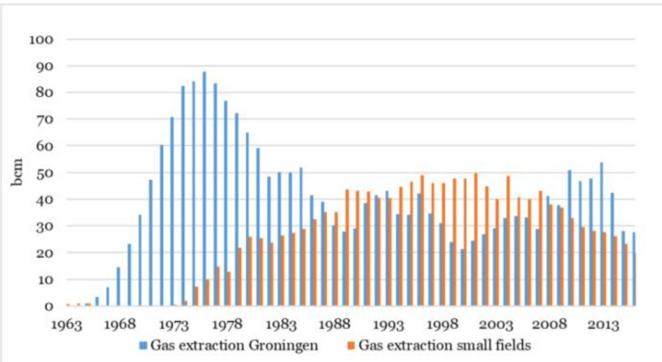
A successful small fields policy was implemented in which preference was given to production from small fields for which the government accepted a smaller share of the revenues. The Groningen field became a swing producer (with high production levels during winters only) and the small fields were produced at maximum capacity throughout the year. Part of the Groningen reserves was to be preserved for later generations as a strategic reserve.

The small fields policy resulted in a pronounced rise of production levels from small fields throughout the late 1970's and 1980's. A number of fields with reserves of several tens of BcM were found during this period, both onshore and offshore. The vast majority of these fields produced gas from the same Rotliegend sands as the reservoir sands for the Groningen gas field.

From 1990 to 2000, small field production stood at a plateau of 40-50 BcM. After 2000, a slow and gradual decline started to set in. We attribute this primarily to geology: the size of new exploration discoveries gradually decreased and new fields were no longer able to fully compensate for the diminishing production from existing fields. The small fields policy was still in place and gas was still receiving widespread support in the Netherlands as a mainstay of Dutch energy supply. Abolishment of depreciation at will (a fiscal measure favouring offshore activities) in 2003, however, can be seen as a first sign of a deteriorating business climate. The new 2003 mining law also implied that local governments and landowners no longer received any benefits from local gas production.

In 2018, total Dutch production from small fields had decreased to 16.2 BcM (about 16% lower than 2017). Groningen production was 18.8 BcM, the minimum required to meet local demand for Groningen spec gas (with a high nitrogen content) and existing export contracts. Increasing the capacity to convert more locally produced gas from small fields and imported gas to Groningen spec gas (by adding nitrogen) will make a complete cessation of Groningen production possible in 2022.

For the small fields, earthquakes have not been the major issue that it became for Groningen. Earthquakes have only been registered for about 10% of the over 300 fields that are or have been producing. Earthquake activity in the small fields, which were depleted much more quickly than the Groningen field, peaked already in the 1990-2005 period. At the time, induced earthquakes were not yet receiving the public attention that they received after 2010. Near-surface soil types above most of the smaller fields with induced earthquakes resulted in smaller surface movements and less damage, for a given magnitude, compared to Groningen (where near surface, low velocity, peat and clay tend to give a relatively large amount of damage). Small fields that are currently brought into production tend to have such a small gas column thickness (and expected reservoir compaction) that the earthquake risk is expected to be minimal.



Source: NAM, CBS

Fig. 1 Groningen and small fields Dutch natural gas production. From Mulder and Perey (2018)

A changing landscape of gas producers

The increasing maturity of the Dutch offshore and onshore gas fields has resulted in a decreasing interest of the major international oil and gas companies. Operating smaller fields that are approaching their end of field life is not their core business. Investments in Dutch small fields do no not score well in a global ranking of their investment opportunities.

For many decades, the Nederlandse Aardolie Maatschappij (NAM, a Shell-ExxonMobil joint venture) had been the dominant operator of Dutch small gas fields. From 2003 onwards, NAM has gradually been divesting small fields and associated licenses and pipelines (mostly to Gaz de France/Engie/Neptune Energy in the offshore; mostly to Vermilion in the onshore). Other majors have followed suit. BP sold its Dutch fields in 2006. Chevron exited the Dutch offshore in 2014. Total unsuccessfully tried to sell its Dutch gas fields in 2018.

In contrast to the majors, mid-size companies such as Wintershall and ONE-Dyas (a merger of Oranje-Nassau Energie and Dyas) have mostly chosen to stay. Wintershall has a long-term focus on the North Sea and the Dutch offshore has been part of this strategy. Vermilion is the only company focusing mostly on the onshore and the most active explorer here.

Initially, utilities such as Gaz de France (from 2015 onwards: Engie) and RWE have bought assets from the majors in mature parts of the North Sea, aiming to increase the share of in-house gas production in their gas consumption. However, lower gas prices and a weak long-term future perspective for natural gas in Europe, as a consequence of climate change and the energy transition, have resulted in a change of strategy for the utilities. Most of them have sold their gas producing assets; often at a significant loss. Engie sold its gas producing assets in the Netherlands in 2018 to private equity-backed Neptune Energy.

Throughout the North Sea area, the role of private equity has significantly increased. Chrysaor, following the 2017 acquisition of part of Shell's UK assets for US$ 3.8 billion, is now a major North Sea operator. The same applies to Neptune, following its acquisition of Engie's oil and gas producing assets for US$ 4.7 billion in 2018. Neptune is currently the largest offshore Dutch gas producer. Although private equity-backed companies do drill exploration wells in the North Sea area, the focus in the Netherlands tends to be more on development than exploration. The absence of depreciation at will and the Dutch tax disadvantages on the shielded abandonment provisions tend to make the UK and Norway more attractive for asset deals.

The private equity firms that fund companies like Neptune and Chrysaor (EIG for Chrysaor, Carlyle and CVC for Neptune) tend to stay out of the limelight. Reduced asset prices (and the majors sometimes remaining responsible for part of the abandonment costs) make North Sea gas production attractive for private equity. Their main challenge will be to sell these assets within 5-10 years' time (often the time window that private equity wants to hold on to assets). It is not a given that the hoped-for higher oil and natural gas prices, and an improved climate for an IPO (Initial Public Offering), will materialise.

A shift from majors to smaller and more nimble operators, with a lower cost base, is expected to have a positive effect on production volumes in a mature area such as the Netherlands. Private equity can be an attractive way of funding smaller operators. Private equity may be a demanding investor but also a knowledgeable and agile one. Public listings for small oil and gas producers have lost much of their attractiveness. Major investors such as banks and pension funds are subject to significant public scrutiny and have become less inclined to invest in fossil fuel production.

A deteriorating investment climate for Dutch gas producers

Over the last decade, TNO (Netherlands organisation for applied scientific research) and EBN (the Dutch state entity that is a non-operating partner in all Dutch oil and gas developments), have created yearly forecasts for the future production from Dutch small gas fields. These are bottom up technical forecasts, created according to the PRMS (Petroleum Resource Management System), taking into account forecasts by operators and based on existing production and potential development and exploration projects. Non-operating partner EBN, in contrast to TNO, is in a position to discount operator forecasts.

EBN has recently published a lookback study on their forecasts and a novel method to estimate future production. It was found that forecasts based on a bottom-up prognosis of production from existing fields and additional development and exploration projects had severely, and consistently, over-estimated future production since 2011. Initially EBN had resorted to using a risk factor for all projects, which (in hindsight) reduced the amount of over-estimation by about 50%. The new method described in 2019 applied a more detailed combination of risk factors (depending on the operator and the nature of the project) as well as a time delay for all projects (varying from 1-4 years). Both risk factors and time delays were now based on the actual performance of Dutch gas producers since 2011. Using this new method to create forecasts from 2011 onwards it was found that errors for the new forecasts were consistently and dramatically reduced with respect to the unrisked operator forecasts and the previous EBN forecasts. A new forecast from 2018 onwards reduced the predicted production in 2030 to approximately 5 BcM (compared to 10-12 BcM for previous 2030 forecasts).

Various factors play a role for the observed over-prediction during the last decade. Over-prediction of uptime for existing assets played a major role for the over-prediction in the short term. Apparently, the operators' estimates of uptime should be seen as a target rather than a mid-case expectation. Over-prediction in the long term was primarily due to an over-estimate of the number of potential projects that materialized, as well as an under-estimate for the time needed to execute these projects. Lower gas prices may have played a role over the second half of the period. In our view the most important component here is a gradually deteriorating investment climate for the Dutch gas industry. This results in a situation where operators are no longer able to fully use the geological opportunities available. It is a view that is, as was confirmed during a number of conversations with various stakeholders, widely shared within the Dutch gas industry.

Following the new mining law, approved by parliament in 2016, procedures to drill new wells are taking an excessive amount of time. Applications for new exploration licenses take longer than a year to be processed by the ministry. To take a new exploration discovery such as the one made by ONE-Dyas, in the North Sea to the North of the Eems estuary and at a small distance from an existing pipeline, to first gas would previously take about 3 years (and in the Southern UK North Sea it still does). In the Netherlands this discovery, made in 2017, is now expected to see first gas in 2023 at the earliest. Planning of seismic, drilling a well, laying a pipeline and installing a new small development platform are a major planning operation. The constant threat that one or several elements of this operation will be cancelled due to permitting issues at a late stage is a major issue for operators.

Local and regional government entities, while not having the final say on gas production, tend to use every available opportunity to lengthen permitting procedures; frequently taking procedures all the way up to the Raad van State, the Dutch supreme administrative court. New onshore wells may still be drilled but new onshore production sites have become virtually impossible to realise. New onshore exploration licenses are no longer being granted.

Within the greater North Sea area, gas fields in the Southern UK North Sea are the closest analogue for the Dutch offshore gas fields (and a competitor for investments). The Dutch tax regime for gas producers is significantly worse than in the UK (50% versus 30% direct tax take). An improved arrangement for the deduction of investments related to exploration and development of small gas fields will not fundamentally change this. This arrangement, announced in May 2018, has not yet (December 2019) been implemented. Political support to implement additional tax measures needed to enable the development of the smallest (and poorest reservoir quality) fields, not or only marginally commercial under the current regime, is not forthcoming.

At a time when estimates of remaining exploration potential stayed virtually unchanged, drilling activity and reserves for the producing small fields dropped to unprecedented low levels. Exploration activity to find new offshore fields is now at about 20% of that in 2012. Dutch gas producers are finding it increasingly difficult to obtain funding from head offices. This is partly due to general factors (increasing geological maturity of the Southern North Sea and relatively low gas prices) but is exacerbated by a number of specifically Dutch circumstances. For the North Sea area, oil and gas producers tend to focus on the UK or Norway, countries that implement a more active and efficient policy to maximise local gas production, rather than the Netherlands.

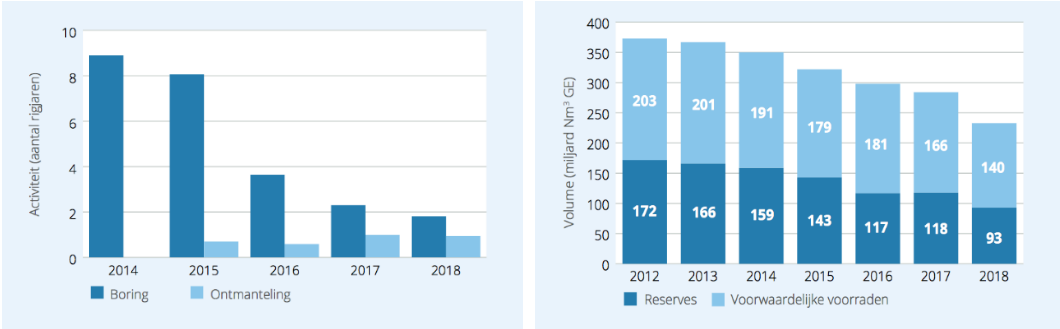


Fig. 2 a) Drilling activity in the Netherlands. b) Reserves from Dutch small gas fields. Source: EBN 2019 focus report.

The deterioration of the investment climate is closely related to a change in the public image of natural gas in the Netherlands. Until 2012 natural gas was usually seen as a relatively clean fossil fuel and a welcome and major source of revenue for the Dutch government. Currently natural gas is seen more negatively; at best as a 'transition fuel' with a limited lifespan on the way to a decarbonised economy. This shift in the public image of natural gas has been more pronounced in the Netherlands than in nearby fossil fuel producing countries like the UK and Norway. Climate change is a major issue in Norway as well, but it has not eroded support for the local production of oil and gas to the extent that it has in the Netherlands. A number of elements play a role here:

- The increasing realisation of the severity of the climate change problem and the increasing momentum to actually start tackling this problem, culminating in the Paris Agreement. Many people see a reduction of Dutch gas production as a welcome element in the fight against climate change.
- The increasing magnitude of earthquakes in the province of Groningen and the plight of people affected by these earthquakes, culminating in the 2012 earthquake near the village of Huizinge that damaged thousands of houses. This damaged the public image of gas in general and the image of the largest producer NAM in particular. The Groningen issues have been projected on other fields and the state has lost credibility as a mediator and problem solver, reducing its effectiveness to promote local gas production from small fields.
- The increasing unpopularity of large corporations such as oil and gas companies in the Netherlands, often perceived to make excessive profits at the expense of local populations.

Significant remaining exploration potential

There is no geological reason why the number of exploration wells has seen such a dramatic decrease (a decline that is much more pronounced than in the neighbouring UK North Sea). Throughout the last 20 years the volume of remaining exploration potential has stayed at a relatively constant level. EBN currently estimates about 200-300 BcM of (risked) exploration potential from the Dutch offshore. Creaming curves imply significant remaining potential for the existing plays. Several underexplored plays exist that have, over the last decade, only been followed up to a limited extent.

Lower Rotliegend sands are a proven play in the Dutch offshore. This play may extend over a large area that has seen little exploration activity so far. Rotliegend sands in a position much further north than the existing belt of southern North Sea gas fields (and sourced from the North rather than the South) are now a producing reservoir in the UK, following the discovery of the Cygnus field. This field, operated by Neptune Energy, started to produce in 2016. With reserves of about 20 BcM it was the largest discovery in the southern North Sea for about 30 years. These reservoir sands are likely to extend into the northernmost part of the Dutch offshore. So far, this play has not been tested in the Netherlands.

Other underexplored plays are Basal Zechstein carbonates, Volpriehausen sands and Shallow Cenozoic sands. An overview can be found in a recent EBN publication. Tulip's Q10 field is so far the only successful Dutch offshore development for Basal Zechstein carbonates. Shallow Cenozoic gas fields have only been developed by Chevron (now operated Petrogas) in the northernmost A and B blocks.

From a technical and geological point of view, the Netherlands has a number of attractive features for a gas producer that is interested in exploring for gas in a mature area. There is a relatively dense infrastructure, an open-door policy for the application for exploration licenses, an excellent documentation by TNO of previous work that is readily accessible on the NLOG website and a high-quality and up to date documentation of potential exploration plays on the EBN site.

A rapid decrease of Dutch gas production in the 2020's

We do not expect, and do not see indications for, an improvement of the investment climate for the Dutch gas industry. We hence assume for a mid-case forecast the forecast from a recent EBN study that assumes that the extent to which operators can make use of geological opportunities in the coming decade will be the same as that for the previous decade. This forecast gives a 2030 Dutch gas production of approximately 5 BcM.

Exploration activities are now at a historic low level and are not expected to pick up in the near future. The political opposition against measures to stimulate local Dutch gas production remains high. Gas producers have a choice and the consensus amongst operators in the North Sea area is that support for the local gas industry is higher in countries like the UK or Norway. The UK has a MER (maximising economic recovery) policy for its oil and gas industry that has been successful to arrest the decline of UK offshore production.

We do not consider a "final sprint for Dutch exploration" a likely scenario. Gas producers are well aware of the political climate for the gas industry in the Netherlands as well as the rapidly decreasing production for a single platform or pipeline system. Over the last few years, operating costs have been relatively constant as cost saving initiatives were able to compensate for a decreasing production; this is not something that can go on indefinitely. With decommissioning of platforms taking off in earnest, the distance from an exploration prospect towards a platform that is still expected to function for the required number of years, will rapidly increase. Several operators have indicated that within a few years there may be interesting prospects in the Dutch offshore (from a geological point of view) but no operators that are interested to drill them.

A further deterioration of the investment climate is a realistic scenario. With an increasing flow of low-cost LNG, primarily from Qatar and the US, LNG is becoming a stronger competitor for local gas production in northwest Europe. Over the coming years an oversupply of LNG is expected to exert a downward pressure on natural gas prices in Europe.

Since May 2019, new permits for Dutch projects that could result in additional nitrogen (more precise: nitrogen oxides and ammonia) emissions are no longer granted. This also applies to exploration and development oil and gas projects, both onshore and offshore, even although emissions from these projects are minimal compared to emissions from agriculture, industry and traffic and only take place over a limited period of time. This is in spite of the much-reduced nitrogen oxides emissions from the Dutch offshore sector due to government regulations that are stricter than in any other European country. To date (January 2020) this ban on new permits still applies. Apart from wells and seismic surveys, even maintenance and decommissioning activities are affected. This has further shaken the already low confidence that gas producers have in the Netherlands.

Our low case scenario is in line with a scenario from EBN where the number of offshore platforms rapidly decreases in a situation where gas prices remain low and a further reduction of operating costs for offshore infrastructure does not materialise. The number of producing fields and active platforms in the Dutch offshore here decreases to zero shortly after 2030. Around this time a small number of producing fields is no longer able to pay for the operating costs of an entire pipeline system. A recent publication by Gasterra, the Dutch wholesaler in natural gas, also refers to a possible production of 2 BcM in 2030.

For a high case scenario, we have assumed a technical bottom-up scenario where operators are able to make greater use of the geological opportunities than in the preceding decade. This forecast predicts a 2030 production of about 10 BcM and is similar to the forecasts that are currently used by the Dutch ministry for economic affairs and climate; see e.g., the recent November 2019 "klimaat en energieverkenning" study. This scenario requires an improvement of the investment climate and/or much greater than expected volumes in forthcoming exploration wells. We consider the high case scenario to be less likely than the low case scenario.

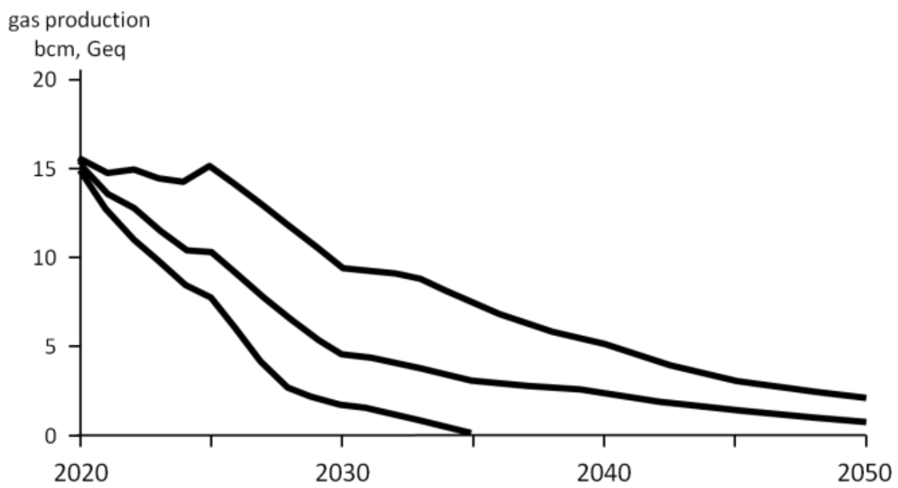


Fig. 3: Low, mid and high case prognosis for future Dutch gas production from small fields.

Discussion

The big changes for natural gas in the Netherlands are currently not taking place on the demand side but on the supply side. From 2013 to 2019 production decreased from 80 to 35 BcM (primarily due to the decrease in Groningen production). Our mid case estimate has Dutch natural gas production, after the planned cessation of Groningen production in 2022, at close to 10 BcM in 2025 and 5 BcM in 2030.

Different scenarios for a forthcoming energy transition show a constant or slowly increasing demand for natural gas consumption in the Netherlands over the coming decade. The first phase of the energy transition, as outlined in the climate agreement, will lead to a gradual reduction of natural gas use in the industry and residential heating sectors. Natural gas use in the power sector, on the other hand, is expected to rise over the coming years as the use of existing natural gas power plants is increasing due to the phase out of coal in the Netherlands and the phase out of both nuclear and coal in neighbouring Germany and Belgium. A switch from coal to gas is currently taking place in many EU countries, primarily due to commercial reasons (low natural gas prices and rising emissions trading system (ETS) prices that have now entered a window that is optimal for gas).

The Netherlands became a net importer of natural gas in 2018. Imports are expected to rise to about 25 BcM in 2025. Discussions are ongoing whether long term contracts for the import of natural gas are needed (and which private or state entity will be responsible for this, following the closure of Gasterra) or whether the Netherlands is comfortable with relying on spot markets only.

Within the EU-28 the decrease of Dutch natural gas production has been primarily compensated by an increase of piped Russian gas imports. From 2014 to 2018 annual Gazprom pipeline exports to Europe increased from less than 150 BcM to over 200 BcM. In 2018 and 2019 the import of LNG in Europe started to significantly increase. European LNG imports are expected to be around 100 BcM for the 2020-2025 period, about double the level of 2010-2017. Competition between Russian gas and LNG (primarily from Qatar, the US and Russia) and an oversupply of LNG following a large number of new projects in the 2014-2020 period is expected to exert a downward pressure on European gas prices for the coming years.

Replacing Dutch gas by imported gas results in significantly higher upstream emissions (related to the production or transport of natural gas). Methane leakages for gas produced in the Netherlands are relatively low, of the order of 0.1%. Both for Russian gas and for US shale gas methane leakages are estimated to be substantially higher, of the order of 2%. Methane is a powerful greenhouse gas (much more powerful than CO_2). Higher methane leakages for imported gas, as well as the energy required to transport gas over long distances (about 10% of the gas that enters the pipeline network in western Siberia is burned in compressor stations in order to transport the gas), results in upstream emissions for imported gas that are about 30% higher than that for Dutch gas (or gas from Norway or the UK).

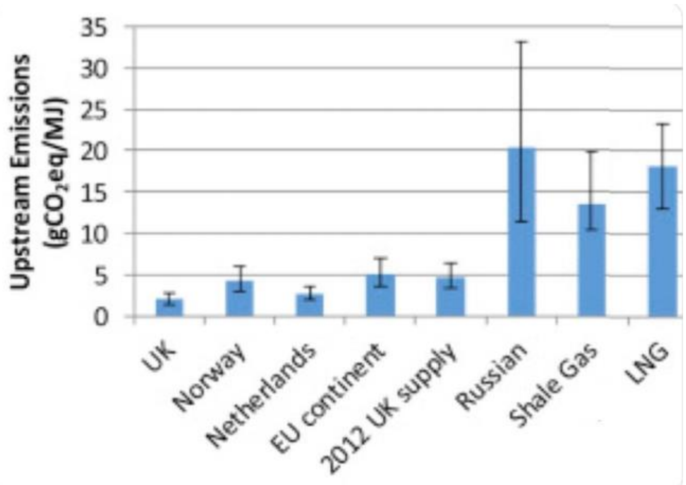


Fig. 4: Upstream emissions for gas consumed in the UK (Hammond and O'Grady, 2017). *For consumption in the Netherlands, Dutch sourced gas emissions will be slightly lower, and UK sourced gas emissions will be slightly higher. LNG denotes LNG from Qatar. Shale gas denotes production only and does not include LNG transport.*

Since 2013, over 40 BcM of Dutch gas has been replaced by Russian gas and LNG with a global carbon footprint that is about 30% higher (thus resulting in additional emissions corresponding to the burning of about 12 BcM of gas). The yearly amount of electricity that is currently generated by solar and wind in the Dutch power mix corresponds to about 50 petajoule (PJ) (about 3-4 BcM of gas fired power production). For the global climate, the replacement in the EU of Dutch gas by Russian gas and LNG thus negates all progress that has been made by increasing the share of solar and wind in the Dutch power mix. This hardly seems to play a role in decision making on Dutch gas production and imports, as these upstream emissions do not have a bearing on Dutch national emission targets.

A rapidly falling production implies that decommissioning of offshore infrastructure will likely be brought forward. Preserving part of the infrastructure for future use in carbon capture and storage (CCS) or blue/green hydrogen projects will become more of a challenge.

Conclusions

Over the last decade, long-term forecasts of Dutch natural gas production have consistently over-estimated production. The main reason for this is not technical or geological but rather an underestimate of the speed at which the business climate for the Dutch gas industry has deteriorated. Fewer projects than expected materialized; the projects that did materialize took a longer time than expected. Permitting procedures are taking a long time, especially after the introduction of a new mining law. The tax regime is less favorable than in the UK southern North Sea. Local governments often use all the options that the new mining law offers them to delay projects as much as possible. The current low gas prices make it more difficult for Dutch gas producers to obtain funding.

In 2018, Dutch natural gas production stood at about 35 BcM; 18.8 BcM from Groningen (now expected to cease production in 2022) and 16.2 BcM from small fields. A technical forecast predicts a 2030 Dutch natural gas production of about 10 BcM. This decrease is solely due to natural production decline of older gas fields in a relatively mature area. It is similar to the forecast that is currently used by the Dutch ministry of economic affairs and climate. As this forecast does not take into account the current relatively poor investment climate for the Dutch natural gas industry, we consider it to be a high case forecast.

A mid case forecast that assumes that the track record of Dutch gas producers to arrest the decline of existing fields and deliver opportunities will remain unchanged with respect to the 2010-2019 period predicts a 2030 annual production of 5 BcM. A low case forecast, assuming a further deterioration of the investment climate (low natural gas prices over an extended period, rising OPEX costs, further regulatory constraints) predicts that by 2030 Dutch natural gas production will have virtually ceased.

With Dutch natural gas consumption expected to be relatively constant over the coming decade, gas imports will rise drastically. Dutch gas is, and will be, replaced by Russian piped gas and LNG imports. The total emission of greenhouse gases for imported natural gas is about 30% higher compared to Dutch gas (due to methane leakages and the energy required to transport gas over long distances). On a global scale, this negates all progress that is currently being made by increasing the share of solar and wind in the Dutch power mix.