NAM

Groningen Pressure Maintenance (GPM) Study

Progress Report February 2016

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Groningen Pressure Maintenance (GPM)

Achtergrond

NAM doet sinds begin 2013 onderzoek naar de mogelijkheden van drukbehoud door gasinjectie in het Groningen gasveld. Het GPM-studieprogramma is een belangrijke prioriteit voor NAM, aangezien drukbehoud – naast het verminderen van gasproductie en het versterken van gebouwen – als een mogelijke veiligheidsmaatregel wordt beschouwd voor het Groningen gasveld. Het programma omvat onderzoek van Shell Global Solutions, alsmede onderzoek door externe wetenschappers en consultants.

Het GPM-studieprogramma is onderdeel van een breder studieprogramma dat is gericht op het evalueren en beheersen van risico's als gevolg van aardbevingen door drukdaling en compactie in het Groningen gasveld.

Overzicht

Het GPM studieprogramma bestaat uit de volgende drie onderdelen:

1. Geomechanische effecten –
    - 'TNO 2014 R11761 Literature review on Injection-Related Induced Seismicity and its relevance to Nitrogen Injection'
    - 'TNO 2015 R10906 Injection-Related Induced Seismicity and its relevance to Nitrogen Injection: Description of Dutch field cases'
    - 'TNO 2015 R11259 Injection Related Induced Seismicity and its relevance to Nitrogen Injection: Modelling of geomechanical effects of injection on fault stability'
    - 'TNO 2015 R11648 Injection Related Induced Seismicity and its relevance to Nitrogen Injection: Main findings, recommendations and general guidelines'

    TNO: onderzoek naar seismiciteit die wordt opgewekt door injectie door middel van literatuurstudies en het modelleren van geomechanische effecten van stikstofinjectie op breukstabiliteit. Deze rapporten worden op de website van TNO gepubliceerd;
2. Technische haalbaarheid - 'Groningen Pressure Maintenance Study', Shell Global Solutions: onderzoek naar de technische haalbaarheid van gasinjectie in het Groningen gasveld met het doel om seismische activiteit en bodemdaling te verminderen door behoud van de druk in het reservoir;
3. Alternatieve opties en mogelijke synergiën - 'Groningen 2.0', professor W. Turkenburg: onderzoek naar de alternatieven en potentiële synergiën tussen GPM en lokale economische of industriële ontwikkelingen in de Groningse regio.

De technische haalbaarheidsstudie toont aan dat stikstofinjectie in het Groningse gasveld technisch haalbaar is en de mate van drukdaling kan verminderen of de druk kan stabiliseren. Op dit moment kan het seismische risico voor GPM echter niet berekend worden en blijft het onzeker of injectie op grote schaal een significant positief of negatief effect heeft op seismische activiteit. Er is veldonderzoek in Groningen en aanvullend onderzoek nodig om vast te stellen of GPM een effectieve manier is om seismische activiteit te verminderen.

Naast de onzekerheden en risico's van injectie, heeft drukbehoud door injectie als nadeel dat het een langere implementatietijd heeft in vergelijking met andere mitigerende maatregelen, zoals bouwkundig versterken. Gezien de schaal en complexiteit van drukbehoud, is een eerste gasinjectie naar verwachting niet voor 2025 te realiseren.

GPM zou een groot en complex project zijn, waarbij er gedurende meerdere jaren boor- en bouwactiviteiten zouden zijn op verschillende locaties in Groningen. In de hele regio zouden pijpleidingen lopen tussen een installatie waar injectiegas wordt gegenereerd en de verschillende injectielocaties. Een dusdanig project zou een grote economische en milieutechnische impact hebben, met een aanzienlijke uitstoot van CO_2.

Wat gaat de NAM met de onderzoeksresultaten doen?

In tegenstelling tot maatregelen als productiebeperking en bouwkundig versterken, kan op dit moment niet bewezen worden dat GPM positief uitpakt voor het risico en is er daarom verder onderzoek nodig.

Omdat het erg lang duurt voordat GPM eventueel effect kan hebben, zal GPM niet worden opgenomen in het Winningsplan dat bij de minister van Economische Zaken wordt ingediend op 1 april 2016.

NAM heeft de resultaten van het GPM-onderzoek overhandigd aan de minister van Economische Zaken voor verdere review, discussie en besluitvorming in de toezichthoudende en democratische processen.

NAM

Groningen Pressure maintenance (GPM)

Background

NAM has been assessing possibilities for pressure maintenance in the Groningen gas field by injection since early 2013. The GPM study programme has been a key priority for NAM, as pressure maintenance is considered as a possible safety measure with regard to the Groningen gas field, along with reducing gas production and reinforcing buildings. The programme includes research by Shell Global Solutions as well as research by external academics and consultants.

The GPM study programme is part of a broader study programme that is aimed at evaluating and managing the risks and impacts resulting from earthquakes due to pressure depletion and reservoir compaction in the Groningen gas field.

Overview

The GPM study programme covered the following three areas:

1. Geomechanical effects –
    - 'TNO 2014 R11761 Literature review on Injection-Related Induced Seismicity and its relevance to Nitrogen Injection'
    - 'TNO 2015 R10906 Injection-Related Induced Seismicity and its relevance to Nitrogen Injection: Description of Dutch field cases'
    - 'TNO 2015 R11259 Injection Related Induced Seismicity and its relevance to Nitrogen Injection: Modelling of geomechanical effects of injection on fault stability'
    - 'TNO 2015 R11648 Injection Related Induced Seismicity and its relevance to Nitrogen Injection: Main findings, recommendations and general guidelines'

   TNO: research into injection induced seismicity by means of literature studies and the modelling of geomechanical effects of nitrogen injection on fault stability. These reports will be published on the website of TNO;
2. Technical feasibility – 'Groningen Pressure Maintenance Study', Shell Global Solutions: research into the technical feasibility of gas injection into the Groningen field with the objective to reduce seismicity and subsidence by sustaining the reservoir pressure;
3. Alternative options and potential synergies – 'Groningen 2.0', Professor W. Turkenburg: research into alternative options and potential synergies between GPM and local economic or industrial developments in the Groningen area.

The technical feasibility study shows that injection of nitrogen into the Groningen field is technically feasible and can reduce the rate of pressure decline or stabilize pressures. However, currently the seismic hazard for GPM cannot be calculated and it remains uncertain whether large scale injection will have a significant positive or negative effect on seismicity. A field test in Groningen and additional research would be required to establish whether GPM is effective in reducing seismicity.

Besides the uncertainties and risks around injection, pressure maintenance through injection has the further disadvantage of a longer implementation time compared to other mitigating measures, such as structural upgrading. Given the size and complexity of a pressure maintenance scheme, a first injection of gas is unlikely to be expected before 2025.

GPM would be a major and complex project with drilling and construction activities over several years across various sites in the Groningen field, with pipelines connecting an injectant generation plant with injection wells across the region. Such a project would have a large economic and environmental impact, such as a significant CO2 footprint.

What is NAM going to do with the study results?

In contrast to the measures like production restrictions and structural upgrading, it can currently not be proven that GPM has a positive effect on risk, and therefore requires further research.

Due to the long term horizon for GPM to possibly take effect, GPM will not be included in the production plan (‘Winningsplan’) that will be submitted to the Minister of Economic Affairs on April 1st 2016.

NAM has handed over the results of the GPM study to the Minister of Economic Affairs for further review, discussion and decision making in the regulatory and democratic processes.

Groningen Pressure Maintenance (GPM) Study
Progress Report, February 2016
by

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Executive Summary

Introduction

The ongoing gas production in the Groningen field leads to a decrease in reservoir pore pressure, causing the reservoir to compact. In turn, reservoir compaction increases the mechanical loads acting on pre-existing geological faults. A small fraction of these faults becomes unstable and is therefore prone to slip. Abrupt slip on such a fault results in an earthquake that radiates seismic energy. The number and magnitude of the earthquakes in the Groningen field cause concern about the future strength of earthquake ground motions and the resilience of existing buildings to these ground motions.

The established and agreed mitigation measures to reduce the seismicity risk in the Groningen field are currently production restrictions and structural upgrading of buildings. For 2014, a production cap of 42.5 bcm/a was introduced by the regulator and for 2015, the cap was set at 30 bcm/a. Besides setting a production ceiling for the total field, production from the north of the field specifically has been limited, requiring production from the south to be increased.

As an additional or alternative possibility to arrest production-induced seismicity, the concept of continued production under pressure maintenance by injection has been studied.

The hypothesis for Groningen Pressure Maintenance (GPM) concepts is that if further compaction can be avoided by maintaining pressure through injection, the number of earthquakes would reduce. Given the large areal extent of the Groningen field and the uneven offtake under the new production caps, pressure imbalances are being built up. If the pressures are not equilibrated first, a future injection scheme will only be able at best to temporarily maintain the different pressures in different parts of the field, but ultimately pressures will equilibrate. Therefore, despite being labelled pressure *maintenance* concepts, all GPM concepts are essentially pressure *management* concepts, however including injection, whereas the ongoing pressure management in the field is achieved by controlling production only. While it is accepted that avoiding further pressure depletion would reduce further seismicity, it is also accepted that injection itself carries the risk of inducing seismicity by destabilising already critically stressed faults by reservoir pressure increases. Depending on the injection scheme, the pressure increase can be confined to circles with radii of several hundred meters around the injection wells or impact larger areas at kilometre scale, in which the pressure rises due to pressure equilibration across the field.

This report gives a status update and summary of the GPM work done for the Nederlandse Aardolie Maatschappij BV (NAM) by Shell Global Solutions. This report focuses on pressure management through injection, whereas the ongoing pressure management by depletion only is discussed separately in other reports.

Study History

This GPM study is part of a major effort to better understand the mechanisms of seismicity in the Groningen field and to ensure that gas from the field can be produced within safe limits. The work was done in preparation of the Groningen Winningsplan 2016, which will lay out the production and development activities for the field for the coming years.

The option of pressure maintenance in Groningen to manage seismicity was first described in a screening study in the Technical Addendum to the Winningsplan 2013 [1]. A single concept with nitrogen (N_2) injection was presented. The N_2 would be generated in air separation units (ASUs) located in Eemshaven and injected in new wells distributed across the field. The returned N_2 in the produced gas was to be removed and recycled for injection again in N_2 rejection units (NRUs) placed at the existing production clusters. The report described the massive dimensions of this large-scale project. The concept was deemed by the Technische Begeleidingscommissie Ondergrond[1] (TBO) as currently too difficult to imagine, given the enormous cost, the loss of production, and the scale of the required infrastructure [6].

Building on the work of the 2013 Winningsplan, the GPM study in 2014/'15 has focused on the following topics:

- Developing a range of pressure management policies and injection well patterns to limit future compaction and thereby reducing production-induced seismicity while at the same time being conscious of the risk of injection-induced seismicity
- Assessing a range of injectants, processes to generate them, and developing concepts for their removal from the produced gas, as part of the injectants will travel through the reservoir to the production wells
- Minimising the environmental impact of the concepts (e.g. use of land, impact on open landscape, energy use, and CO_2 emissions) and minimising personal and process safety risks during construction and operation
- Gaining a better understanding of the potentially increased risk of seismicity from injection in the Groningen field
- Developing concepts for an injection test to de-risk the potential negative effect on seismicity risk that injection may have

In addition, external studies related to GPM have been conducted by TNO and the Groningen 2.0 study group.

Seismic Hazard for Injection Concepts

The aim of GPM is to avoid and/or defer future seismicity by avoiding and/or deferring future pressure decline. The benefits of GPM in avoiding or deferring seismicity can be evaluated using elements of the current NAM-developed probabilistic seismic hazard and risk model for Groningen [4]. This model is built on historical observations under depletion, relating compaction, and seismicity. However, for injection, which can cause pore pressure increases, no suitable field data, analogues, or predictive models exist to describe injection-induced seismicity in a strongly depleted field like Groningen. This means that, currently, only the benefits of GPM can be quantified but not the potential detrimental effects from injection. Adding the seismicity reduction from maintaining pressures with the additional seismicity from injection might lead to an overall seismicity reduction, or an insignificant change, or an overall increase of seismicity with GPM. Therefore, a range of injection concepts is being studied that either accept pore pressure increases or as much as possible avoid those pore pressure increases.

The concern is that such a pore pressure increase in the depleted Groningen field may induce additional earthquakes, notably because many faults may now be critically stressed by the depletion-induced compaction that accumulated over the more than five decades of production. Taken together, information from analogue fields and global injection cases does not point to strong earthquakes after injection in depleted reservoirs, but rather suggests that seismicity may be low or absent during injection, or only occurs when injection pressures approach virgin pressures. However, as always, one must recall that every field is different, and predictions based on analogue fields remain highly speculative until proven by field data. The theory of frictional slip indicates that, due to injection, such faults may become more prone to fault slip, and thus probably also to seismicity, in particular if the total horizontal stress does not increase (substantially) as a

[1] Technical Guidance Committee Subsurface, advising the Dutch Ministry of Economic Affairs.

function of the increase in pore pressure (i.e. if there is an absence of a coupling effect between the pore pressure and the horizontal stress). The recent modelling studies emphasise the importance of the coupling – if the coupling *is* present and if it is sufficiently large, the tendency of fault slip and seismicity may actually *decrease* as a function of increasing pore pressure. However, the stress path is not the only parameter. There will be effects of virgin stress state (magnitude and orientation), fault plane orientation, fault offset, plasticity, pore pressure diffusion, and temperature as well. Their complex interplay will control the stress state in reservoir and in fault gouge, thus controlling the deformation mechanisms active in fault gouge and the rock between the faults.

Modelling studies of injection-related seismicity have been done at TNO and in-house, preceded by extensive literature reviews. Further work is ongoing on rupture modelling and post-failure fault stabilisation.

Injection Field Testing

Given the uncertainties around injection-induced seismicity, testing of injection in the Groningen field itself should be seen as a prerequisite before implementing a full-field GPM concept. Using existing wells and facilities, it could be possible to temporarily inject hydrocarbon gas at rates of up to 7 bcm/a for several weeks or months to locally increase the reservoir pressure in a controlled way, measure any change in seismicity, and establish whether injection is feasible. Furthermore, an injection test may give insight into the deformation mechanisms and stress path during injection, providing the basis for mechanism-based modelling of how injection may affect fault slip. However, in the absence of predictive models for injection-induced seismicity, the seismic hazard and risks of a test itself cannot be established. Furthermore, the representativeness for other locations cannot be demonstrated and, therefore, multiple tests may be required.

If the risk of injection field-tests triggering unwanted seismicity could be shown to be tolerable, GPM concepts could be envisaged that would include individual, sequential testing at all future injection locations while the project is being implemented. In this step-wise approach, the injection concept would only be fully implemented if all locations have positive test results. Otherwise, if too many locations show negative results, the concept would be left unfinished and only partially operated or completely abandoned. This option of a step-wise implementation is yet to be worked out in more detail.

Through a parallel approach of modelling and high-quality in-situ data collection, it is thought that progress can be made in gaining a mechanism-based understanding of injection-induced fault slip, so that the findings of the injection test can be applied to GPM concepts across the Groningen field.

Pressure Management Policies

The production policies on the Groningen field since early 2014 are resulting in an increasing pressure difference between the northern part of the field remaining at relatively higher pore pressures and the south part of the field depleting to relatively lower pressures. This has implications for GPM: At the start of GPM, choices exist for the pressure levels at which to stabilise the different regions and how and when to equilibrate the pressures again. The selection of a pressure management policy would depend on the overall GPM seismicity "balance", in which the risk of injection-induced seismicity counteracts the benefit of avoided compaction-induced seismicity:

- If reservoir pressure increases were not deemed acceptable, the local repressurisation around the injector wells would have to be minimised, limiting the practical injection and production rates of the field. At the same time, areas in the reservoir that at the start of

GPM are at higher pressures would have to be depleted further to equilibrate with the lowest pressures in the reservoir to avoid a pressure increase in those more depleted areas. This would be an approach, in which the risk of injection-induced seismicity is minimised, but at the expense of increased seismicity from the areas that need to be depleted further.

- If reservoir pressure increases were deemed acceptable, higher injection and production rates would be possible. Furthermore, the pressure in the higher-pressure areas at the start of GPM could be stabilised and any further compaction-induced seismicity in these areas could be minimised, while areas of lower pressure would be allowed to increase in pressure to equilibrate with the higher-pressure areas.

It should be noted that the risk associated with repressurisation does not only apply to GPM cases but also to the cessation of production of the depletion case in which the lower, southern pressure would be left to increase and equilibrate with the northern pressure. However, it should be noted that the southern area has shown to be less prone to seismicity.

Injection Patterns

Depending on the desired pressure management policy for GPM, different injector-producer configurations would have to be selected. Four patterns have been defined as archetypes:

- a field-wide injector-producer pattern ("dispersed pattern", similar to the one described in the externally shared 2013 Winningsplan)
- an injector-producer pattern confined to the north of the field ("semi-dispersed")
- a flank injection in the north ("north-south sweep")
- a local injection cluster ("central")

The injection pattern affects how well the injectant sweeps the reservoir, i.e. how much natural gas is by-passed in the reservoir and left unrecovered, and the time for the injectant to reach the producer wells. The recovery under pressure maintenance can be up to 100 bcm lower, compared to ongoing depletion with third-stage compression, which corresponds to approximately 25% of the remaining recovery after 2025.

With tighter constraints on the allowable pressure increase around injector wells and the allowable degree of regional repressurisation, the forecasted feasible injection and production rates under GPM are now lower and range from 10 to 30 bcm/a, as opposed to 30 to 40 bcm/a in the Winningsplan 2013. The main reason for that is the assumed later start date of GPM. In the Winningsplan 2013, GPM aimed at replacing voidage, while in the further study a wider range of pressure management policies has been studied. These pressure management policies include cases in which pressures are restored to their highest value at the start of GPM and also cases in which repressurisation is avoided and pressures converge at the lowest levels found in the field at the start of GPM.

Injectants and Facilities

Several possible injectants have been reviewed for potential application in an injection scheme, including water, pure N_2 (from air or flue gas from power stations), pure CO_2 (from flue gas), and combinations of N_2 and CO_2. Nitrogen generation with ASUs as described already in the Winningsplan 2013 has been shown to be technically feasible and remains the preferred option for pure N_2 generation. Water and pure CO_2 injection are not feasible.

The compression of the injection gas from atmospheric pressure (air or flue gas) to about 140 bar injection pressure requires a large incremental amount of electricity (400 to 1000 MW), which comes with a significant incremental indirect CO_2 emission of up to 8 mln t/a (depending on the energy source) compared to the ongoing depletion case. In order to lower the CO_2 footprint, the option exists to co-inject a large fraction of the indirectly emitted CO_2 with the N_2 and store the CO_2 in the Groningen field. CO_2 could be captured at the RWE/Essent coal-fired Eemshaven plant through a Cansolv process and mixed with the N_2 from ASUs. Alternatively, flue gas from the Nuon Magnum power plant in Eemshaven could be captured, its O_2 content reduced in an additional boiler, and the flue gas injected directly without the need for separate N_2 generation in ASUs. Breakthrough of the CO_2-containing injectant and flow through the existing production wells and facilities (albeit with minor modifications) can be tolerated up to CO_2 concentrations of 16% in the produced stream. However, the well integrity for some already abandoned wells for long-term CO_2 storage would need further consideration. In the option with ASUs and separate CO_2 capture (i.e. not when directly using flue gas), the pure CO_2 could also be considered for disposal in other depleted fields either onshore or offshore; however, the feasibility for this has not been established.

Any injectant will eventually be back-produced in the production wells. To remove the excess N_2 from the produced gas, cryogenic separation with NRUs was shown to be feasible. Depending on the amount of N_2 produced, the option exists to eliminate or at least defer the NRUs by blending the produced gas with high-calorific gas to supply the required, original Groningen gas quality to the market.

Health and Safety Risks Related to Surface Facilities and Environmental Impact

As for any large-scale industrial project, the potential impacts on the environment and on health and safety of people living near or working at the facilities need to be assessed.

The key environmental issues for a full-field GPM implementation would be the large indirect CO_2 emissions associated with the required electrical power, land use for new wells and facilities, noise emissions, and visual impact.

As described above, the options for flue gas injection and co-injecting a large fraction of the indirectly emitted CO_2 into the Groningen field exist. Alternatively, separate injection of pure CO_2 into other, depleted fields could be studied further.

Land use, noise emissions, and visual impact for GPM would be minimised by drilling new injection wells as much as possible from existing production clusters and only using observation well sites or new well sites where necessary, laying new pipelines in existing pipeline corridors, and siting the large ASU and NRU facilities in industrial areas like Eemshaven or Delfzijl.

Identified safety risks for construction and operation would have to be minimised to an acceptable level. Safeguarding and integrity of wells, pipelines, and facilities is paramount. This means ensuring the facilities are well designed, safely operated, and properly inspected and maintained to prevent process safety incidents that could place people, the environment, and the facilities at risk. Specific health, safety, and environmental (HSE) risks for GPM have been identified, and it can be concluded that the identified risks related to the facilities are manageable and GPM concepts can be implemented and operated responsibly. However, as mentioned before, it is not yet possible to assess to which extent GPM would decrease or possibly increase the risk from seismicity.

External Studies

The Groningen 2.0 team − an independent team of experts from academia and energy consultancies − assessed improvements for the GPM case described in the 2013 Winningsplan and looked for alternative options and potential synergies between GPM and local economic or industrial developments in the Groningen area. Some synergies were identified, such as the use of O_2, and other potential by-products from the ASU (argon, helium) and waste heat from compression were identified. However, given the size of the GPM concepts, the stream of by-products and waste heat are far larger than could be absorbed by local developments, and therefore do not materially change or improve the GPM concepts. Nevertheless, those synergies should be considered if GPM is developed further to make GPM as beneficial for the region as possible.

Conclusions and Way-forward

Injection of N_2 (with optionally some CO_2) into the Groningen field is technically feasible and can reduce the rate of pressure decline or stabilise pressures.

A reduction in or halt of pressure decline would slow down or stop further compaction and consequently slow down or stop further compaction-induced seismicity while production continues from the field. However, the risk of injection-induced seismicity from increased pore pressures during injection exists. Whereas the benefits of a reduced rate of pressure decline or pressure maintenance could be estimated with the currently being developed probabilistic seismic hazard and risk model for Groningen, the effects of pore pressure increase – for which no suitable field data, analogues or predictive models exist – cannot be quantified and therefore, an overall assessment of the benefits of GPM concepts cannot be accomplished.

Given the uncertainty and risk of injection-induced seismicity, pressure management policies could be envisaged that, as far as is possible, avoid pore pressure increases during an injection scheme. Furthermore, testing of injection in the Groningen field itself needs to be considered before implementing a full-field GPM concept. Additionally, GPM implementation scenarios can be envisaged that consider phased implementation, including “test-as-you-build” of injection wells.

Besides the uncertainties and risks around the injection-induced seismicity, compared to the measures of production restrictions and structural upgrading, pressure maintenance through injection has the further disadvantage of a longer implementation time: Given the size and complexity of a pressure maintenance scheme, a first injection of N_2 is unlikely to be expected before the mid-2020s. Additionally, as with any injection scheme, N_2 injection will lead to a significant loss in ultimate recovery (UR) compared to ongoing depletion due to bypassing of hydrocarbon gas by N_2.

As opposed to production restrictions combined with structural upgrading, pressure maintenance can currently only be seen as an alternative to be implemented if production restrictions combined with structural upgrading are not acceptable. Pressure maintenance requires first a scientific consensus on how to assess the safety risks of injection in Groningen – also for field-testing.

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Abbreviations

ASU	air separation unit
Bcm	billion cubic meters (10^9)
CCS	carbon capture and sequestration
EGR	enhanced gas recovery
EOR	enhanced oil recovery
EZ	Dutch Ministry of Economic Affairs (*nl.* Ministerie van Economische Zaken)
GPM	Groningen Pressure Maintenance study
GTS	Gas Transport Services (GTS) acts as an independent transmission system operator in the Netherlands and is a subsidiary of Gasunie, who owns the national gas transmission network
HiCal	High-calorific (non-Groningen) gas
IUCN	International Union for Conservation of Nature
KNMI	Royal Netherlands Meteorological Institute (*nl.* Koninklijk Nederlands Meteorologisch Instituut)
LoCal	Low-calorific (Groningen) gas
MC	Mohr-Coulomb
M_l	Local earthquake magnitude on Richter scale
Mrd	milliard (US: billion, 10^9)
NAM	Nederlandse Aardolie Maatschappij BV
NORM	naturally occuring radioactive material
NRU	nitrogen rejection unit
SCU	shear capacity utilisation
TBO	Ministerial Technical Guidance Committee Sub-surface (*nl.* Technische Begeleidingscommissie Ondergrond) to oversee 2013 work on seismic hazard and pressure maintenance
TNO	Dutch Organisation for Applied Scientific Research (*nl.* Nederlandse Organisatie voor Toegepast Natuurwetenschappelijk Onderzoek)
TVNAP	True Vertical depth below Amsterdam Ordnance Datum (*nl.* Normaal Amsterdams Peil, NAP)
UGS	underground gas storage
UR	ultimate recovery
WRFM	Well, Reservoir and Facilities Management

Production Clusters and Other Well Sites

AMS	Amsweer
BDM	Bedum
BHM	Blijham
BIR	Bierum
BOL	Bolderij
BRH	Barnheem
BRW	Borgsweer
BTA	Beerta
DZL	Delfzijl
EKL	Eemskanaal
EKR	De Eeker
EMHZ	Emshoern
FRB	Froombosch
FRM	Farmsum
GHS	Groothusen
HAR	Haren
HGL	Heiligerlee
HND	De Hond
HRS	Harkstede
KHM	Kolham
KPD	Kooipolder
KWR	Kielwindeweer
LRM	Leermens
MDN	Meeden
MLA	Midlaren
MOW	Moewensteert
MWD	Midwolda
NBR	Noordbroek
NWS	Nieuw Scheemda
ODP	Oldorp
OLD	Oostwold
OPK	Oude Pekela

OVS	Overschild
PAU	De Paauwen
POS	Ten Post
PPS	Paapsand
RDW	Rodewolt
SAP	Sappemeer
SAU	Sauwerd
SCB	Schaapbulten
SDM	Stedum
SLO	Slochteren
SMR	Schildmeer
SPH	Schaaphok
SPI	Spitsbergen
SWO	Schildwolde
SZW	Scheemderzwaag
TBR	Ten Boer
TJM	Tjuchem
TUS	Tusschenklappen
UHM	Uithuizermeeden
UHZ	Uithuizen
USQ	Usquert
UTB	Uiterburen
WBL	Woudbloem
WRF	Warffum
WSM	Winsum
WTD	Westerdiep
ZND	t Zand
ZPD	Zuiderpolder
ZRP	Zeerijp
ZVN	Zuiderveen
ZWD	Zuidwending

1. Introduction

1.1. Study Overview

Since the mid-1980s, relatively small earth tremors have been observed in the vicinity of producing gas fields in the northern Netherlands. Since then, several multidisciplinary studies have been initiated by the Dutch Ministry of Economic Affairs. A borehole seismometer network managed by the Royal Dutch Meteorological Institute (KNMI) was installed in Groningen in 1995 to detect tremors, pinpoint their location, and quantify their magnitude. Accelerometers were also installed in areas where tremors frequently occurred.

In 2012, an earthquake with magnitude M_l = 3.6 occurred near the village of Huizinge in the Loppersum area (16/08/2012). This earthquake was experienced as more intense than previous earthquakes in the same area and caused a significantly larger number of reports of building damage than previous earthquakes (Figure A1.4).

As a response, a study and data acquisition programme was started by NAM in late 2012. In December 2013, NAM published the results of the 2013 work in the Technical Addendum of the Winningsplan 2013 [1]. These results included geomechanical and seismological studies into the induced earthquakes in the Groningen field based on the historical earthquake record with forecasts of future seismicity, an analysis of the reservoir compaction and subsidence with forecasts of future compaction and subsidence and the impact of different depletion scenarios on the seismic hazard.

It is now well established that the seismicity in Groningen is caused by depletion-induced compaction, known for many years to cause seismicity at producing hydrocarbon reservoirs [8], [9]. Recent study work in Shell on the Groningen seismicity [5] has led to a model predicting that further depletion will probably lead to more and possibly stronger earthquakes. The model is based on a relationship between compaction strain, inverted from subsidence, and seismicity. Based on this model, one can postulate that reducing or stopping the depletion in Groningen will reduce or stop reservoir compaction, and thus reduce or stop compaction-induced seismicity, which is the key premise for GPM.

In a parallel effort [43], an empirical relation between the amount of Groningen earthquakes and depletion was used to predict future seismicity. With depletion being the driving force for earthquakes, reducing the depletion (and thus the compaction) was expected to reduce seismicity.

The Technical Addendum of the 2013 Winningsplan [1] also contained a high-level description of a potential concept to maintain pressure in the Groningen field by replacing the gas produced through injection of nitrogen (N_2). This pressure maintenance scheme based on N_2 injection was presented as a potential mitigation measure for induced earthquakes. The dimensions of such a project were given, demonstrating the substantial electrical power requirement and the high impact on the surroundings. However, the feasibility and efficiency of this process at that time could not be confirmed. The fact that injection itself can lead to earthquakes was highlighted and it was also stressed that the current workflow to assess the seismic hazard is only calibrated for pressure depletion and not tested nor validated for injection. No other workflows were identified that could quantify the seismic hazard as a result of injection for the Groningen field. No suitable analogues were available, as most of them are based on the injection of (waste) water in different geological settings and stress regimes.

The Winningsplan 2013 [1] was approved by the Dutch Ministry of Economic Affairs in 2014 requiring an update of the Winningsplan again in 2016 [2]. In preparation of the next Winningsplan, the study and data acquisition programme has been updated [2] and covers

- updates to the seismic hazard and risk assessment, with ways to reduce the uncertainty in that assessment and the impact of the seismic hazard on buildings and safety,
- improved monitoring of compaction, subsidence, and seismicity,
- increased understanding of the mechanisms leading to induced seismicity, and
- identification of measures to reduce the hazard and risk, including the evaluation of their effectiveness as well as early steer on the deployment of any mitigation measures.

Measures to take that would mitigate the seismic risk/impact to be studied are 1) different production policies, which includes pressure maintenance through injection and 2) strengthening of buildings. Whereas the intention of different production policies is to reduce the seismic hazard, i.e. the number, frequency and/or strength of earth tremors, the intention of building strengthening is to address the seismic risk.

Building on the early assessment of a N_2 injection scheme in the 2013 Winningsplan ([1], Technical Addendum), further work has been conducted since early 2014. The work has focussed on the following aspects:

- Geomechanics - In this area, several sub-studies have been performed or are being completed at the time of writing: TNO has conducted a literature study for injection-induced seismicity [3], described Dutch field cases with injection, performed modelling of geomechanical effects of N_2 injection on fault stability.
- Subsurface concepts - Using the available NAM subsurface model for the Groningen field, Shell Global Solutions has evaluated a range of injection and production patterns for different pressure management policies and estimated the according injection and production rates and the impact on the recovery of Groningen gas.
- Surface concepts - Shell Global Solutions has also reviewed the choice of injectants, as well as the methods for generation, distribution, and removal of the injectant from the produced gas. Cost and schedules for new wells, pipelines, and facilities and associated safety and environmental aspects have been evaluated to assess the footprint of a range of injection schemes.
- Synergies - Under the title Groningen 2.0, a group of experts has investigated alternatives to the pressure maintenance concept described in the 2013 Winningsplan, with a focus on surface measures and potential synergies with other developments in the region.

The early conclusions from the Winningsplan 2013 [1] with respect to pressure maintenance are supported; however, a wider range of pressure management policies and according facilities concepts have now been evaluated. While these concepts are all deemed technically feasible, the effectiveness of such injection schemes to reduce seismicity compared to the ongoing depletion case could not yet be established. A field injection test may allow a better assessment of the risk of triggering additional seismicity by injection, but even such a test may not give a definitive answer.

This report gives a status update and summary of the GPM work done for NAM by Shell Global Solutions.

1.2. Potential Role of GPM in Managing Seismicity

The ongoing gas production from the Groningen field leads to a decrease of the pressure of hydrocarbon gas within the reservoir pore space, causing the reservoir to compact (ref. Figure 1.1). In turn, reservoir compaction increases the mechanical loads acting on pre-existing geological faults within and close to the reservoir. A small fraction of these faults becomes unstable and is therefore prone to slip. Abrupt slip on such a fault results in an earthquake that radiates seismic energy. This has been described in detail by Stephen Bourne et al. [5], [11].

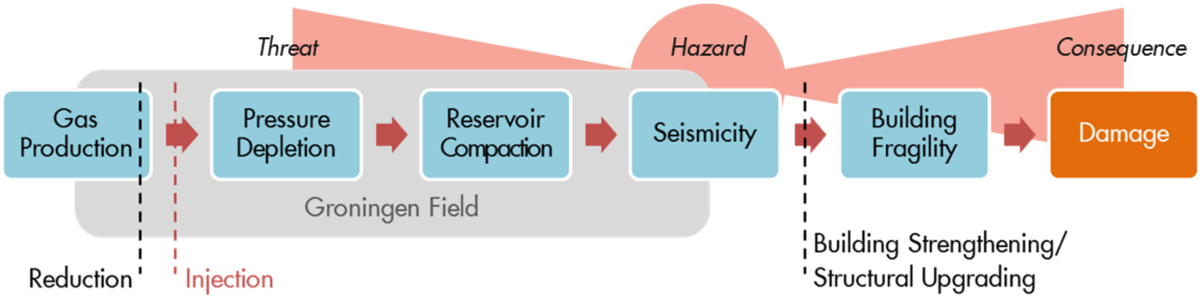

Figure 1.1: Cause and effect chain from gas production to damage and incidents caused by seismicity in the Groningen field and potential mitigation measures.

In order to reduce the risk of building damage, (partial) collapse and injuries, several barriers can be envisaged:

1) structural upgrading to make buildings more resilient to ground movements
2) reduced pressure depletion by reduced production
3) Optimised depletion strategy as SodM/MEA requested from NAM by year-end 2016 and
4) reduced pressure depletion by complementing production with injection.

Structural upgrading is the most effective barrier to reduce the impact [4]. It can be targeted specifically to the most vulnerable buildings in the areas with the highest level of seismicity. Furthermore, following the structural upgrading, the risk reduction is immediately in effect. Changes to the field production policy (e.g. reduced total rate, adjusted areal distribution of offtake) are perhaps less effective, although it can take more time for the effect to be felt. In contrast, controlling the reservoir pressure through injection requires developing, designing, and building a new infrastructure with wells, pipelines, and facilities, which will take several years and therefore would take significantly longer before becoming effective. Only in that situation would pressure maintenance be implemented, and only if:

- the concept was proven to be effective in reducing the earthquakes (likely requiring field trials) and operating within acceptable safety limits with regards to injection-induced seismicity,
- the remaining gas volumes in the field would justify the significant investment, and finally
- society and the regulator approved of this large-scale project.

Feasibility of GPM is not yet confirmed. No firm plans exist currently to test or implement such a concept.

1.3. GPM Concepts

An overall GPM concept consists of a number of technical elements (Figure 1.2):

- Pressure management policy: reservoir pressure at field abandonment and tolerances to pressure increases and decreases during GPM
- Injection and production pattern and rates
- Requirements for testing/appraisal of GPM before a full-field implementation
- Injection medium
- Type of facilities for a) injection medium sourcing/generation and processing and b) produced gas treatment and/or blending with high-calorific gas
- Project execution planning and phasing.

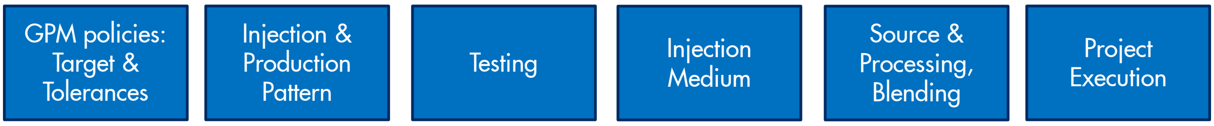

Figure 1.2: The elements that make up an overall GPM concept.

After discussing the possible impact of pressure on seismicity and a Groningen field description in chapters 1 and 3, respectively, the above elements will be considered.

The range of possible pressure management policies and the logically corresponding injection and production patterns will be discussed in chapter 4. Testing and test objectives for the different pressure management policies are covered in chapter 5. The different injection medium options that have been considered and the corresponding surface infrastructure and facilities are described in chapter 6. In chapter 7, the subsurface and surface concepts are considered from the perspective of operations and Health, Safety and Environment (HSE). The implementation of GPM is discussed in chapter 8, including a hypothetical execution schedule. In chapter 9, the pros and cons of the range of possible GPM subsurface and surface concepts are considered, and an initial screening of the concepts is made.

The key aspects for developing and assessing GPM concepts are (ref. Figure 1.3):

1) Seismic risk reduction - GPM concepts need to reduce the seismicity. Apart from production restrictions, GPM is the only obvious risk mitigation option identified with the potential to reduce the compaction induced seismic hazard. GPM could aim either for a temporary deferment of seismicity by delaying depletion or a lifecycle reduction of seismicity by avoiding final depletion (ref. Figure 1.4). Besides the compaction induced seismic risk, the potential injection induced seismic risk must be considered.
2) Public acceptance - GPM acceptance by the key stakeholders, i.e. the communities impacted by the earthquakes, the direct neighbours of any existing or new Groningen field installations, various interest groups and NGOs, the regulator and the local, provincial, and national governments. This acceptability is related to safety risks and nuisances from project execution and operations (including the landscape impact); the delivery time for the project; the impact to the environment, including carbon footprint; the security of gas supply; and a clear cost-benefit compared to other options.
3) Schedule - GPM concepts should have short yet practical durations for design, construction, and commissioning for early effectiveness.
4) Costs - GPM concepts need to be cost-effective, with capital and operational costs in proportion to the benefits in seismic risk reduction and protected gas recovery and production.

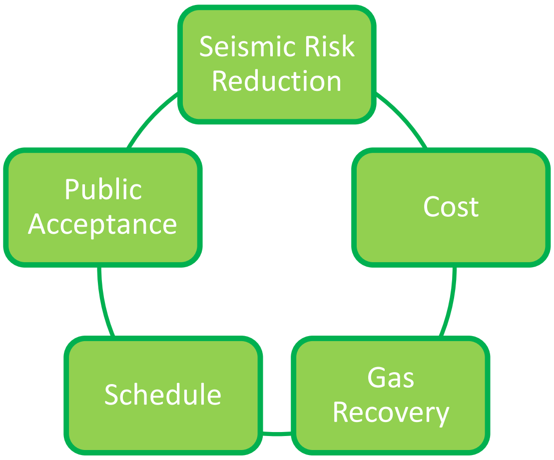

Figure 1.3: **Key aspects for the development and assessment of the GPM concepts.**

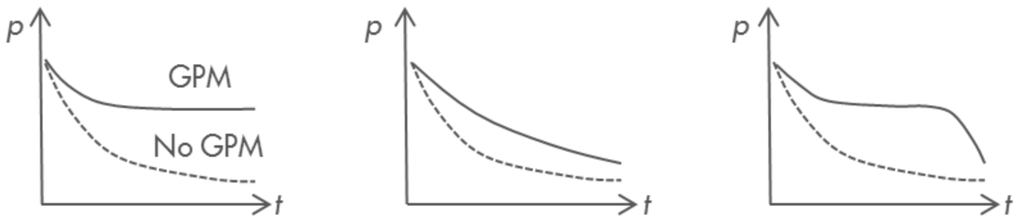

Figure 1.4: **GPM concepts can completely avoid further pressure decline (left), slow down pressure decline (centre), or defer further pressure decline (right).**

The evaluation of GPM concepts requires reasonable estimates of the expected seismic risk reduction, the required injection rates and achievable production rates, the scope of the concept (wells, facilities, pipelines), and the associated environmental and social impact, but also the associated cost and the duration to design, procure, construct, commission, operate, and decommission the project scope.

Existing reservoir simulation models for the Groningen field allow making injection and production rate forecasts for different pressure maintenance and pressure management policies. Those forecasts are inherently uncertain, in particular, due to the underlying geological uncertainty. For a given project scope, cost can be estimated based on past project experiences; those estimates carry a degree of uncertainty due to the scope being incomplete or only defined at high level and the general price uncertainty. For a given project scope, schedules also can be developed based on past project experiences, which also will carry an uncertainty due to scope being incomplete or only defined at a coarse level and with unforeseen interdependencies and events.

The most uncertain element is the seismic risk: As of yet, the seismic risk under GPM cannot be assessed quantitatively. For continued depletion, seismicity can be estimated from compaction with the existing probabilistic seismic hazard and risk model for Groningen. However, this model is not valid if pressure in the field (or parts thereof) increases. Field examples and mechanism-based models show a potential for seismicity induced by pore pressure increase. There are two mechanisms for pressure increase under GPM. First, to enable injection, the area around the injection well needs to have an elevated pressure. This area is localised to a few hundreds of meters around the well. The total pressure difference between the injection well location and the average region can be restricted to about 5 bar at the disadvantage of a low injection rate per well. Second, regional pressure differences could give rise to pressure equilibration once production and injection have stopped, with some pressures in some regions dropping and pressures in other regions rising. As a result, pressure could increase by tens of bars over a large area of the field.

A qualitative assessment of seismic risk under GPM will be based on two indicators, additional compaction and pressure increase. These indicators can be shown in "heat" maps covering a certain period in time. An example is shown in Figure 1.5.

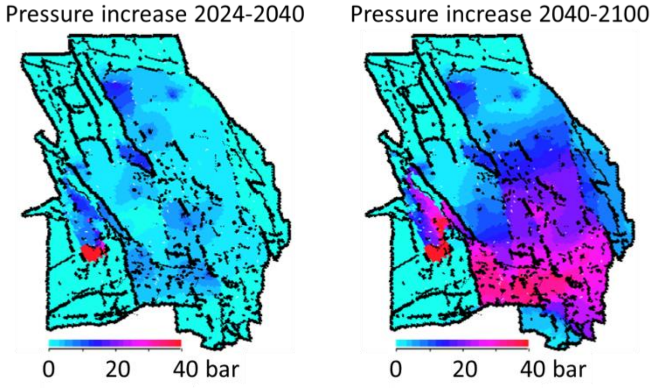

Figure 1.5: **Examples of maps of pore pressure increase for two different periods in time. (Note that the shown repressurisation in the Eemskanaal area, at the western flank of the modelled area is due to a strong aquifer, which is perceived to be a model artefact.)**

There are two classes of GPM concepts (ref. Figure 1.6): If GPM is implemented with confidence that a pressure increase will have a benign effect on seismicity, further compaction can be minimised by increasing pressure in the field to match the highest regional pressure. If the assumption is that pressure increases should be kept to a minimum, further depletion in some areas of the field to the lowest regional pressure needs to be allowed. This highlights the fundamental dilemma of a GPM implementation when the field is in a regional pressure imbalance at the start of GPM. Maximum effectiveness requires confidence in the safety of a pressure increase. As explained in chapter 5, a field test is unlikely to provide the technical evidence to build such confidence.

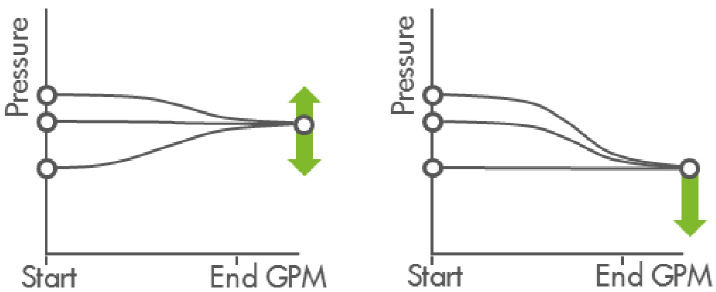

Figure 1.6: **Two classes of GPM concepts. Left, GPM is implemented with confidence that a pressure increase will have a benign effect on seismicity. Pressure could equilibrate below or above the average field pressure at the start of GPM, as indicated by the green arrow. Right, GPM is implemented such that a pressure increase is avoided that could induce additional seismicity. To avoid such a regional pressure increase, pressures should equilibrate at or below the pressure in the south at the start of GPM, as indicated by the green arrow.**

2. Geomechanical Aspects of GPM

2.1. Introduction

Depletion-induced reservoir compaction is accompanied by changes in stress at faults in and around the reservoir. This can lead to slip along geologic faults or create new faults, occasionally with a sudden release of energy leading to ground motion (induced seismicity, see e.g. Segall [8], Grasso [9], Suckale [42], Klose [10]). Regarding the depletion-induced seismicity in the Groningen field (ref. [1]), a recent seismological model in 2014 by Bourne et al. [5] predicts that further depletion will probably lead to more earthquakes, and possibly also to stronger earthquakes than the Huizinge one (16/08/2012, 3.6 on Richter scale, local magnitude M_l). As outlined in chapter 1, one way to mitigate further seismicity is to stop or reduce further depletion by injection of a gaseous medium like N_2 during Groningen gas production: hence, less compaction means less build-up of shear stress at the faults, and thus less driving force for fault slip. Models for GPM indicate that pressure maintenance can reduce the volume of reservoir compaction after 2015 by 22% to 35% compared to the depletion-only case, depending on the GPM scenario (Figure 2.1), suggesting its potential to reduce depletion-induced seismicity in the Groningen field (see also Hagoort [43]).

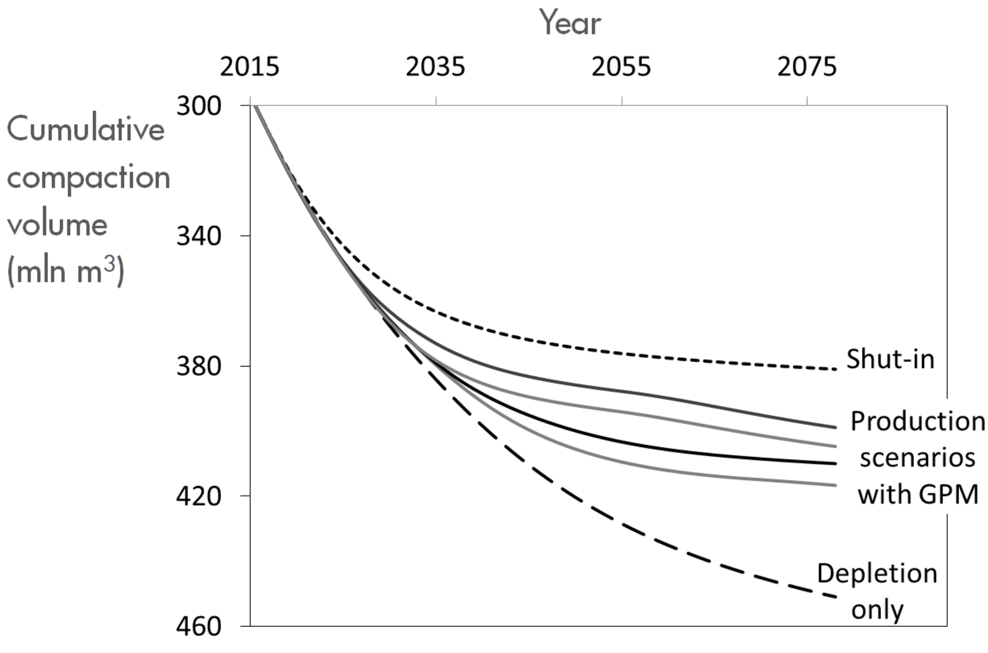

Figure 2.1: Compaction volumes calculated for continued depletion, shut-in, and a number of GPM scenarios, including north-to-south gas sweep, central injection, and dispersed injection. Implementation of GPM would reduce the cumulative compaction volume of Groningen reservoir rock after 2015 by 23% to 35%.

But there is a geomechanical caveat to GPM: The models also indicate that during a field-wide GPM implementation, the pore fluid pressure may actually *increase*. This can occur around the injector wells to provide the driving force for the injection gas to flow into the reservoir, and during field-wide pore pressure equilibration when the field is shut-in, with the southern part of the field gradually increasing in pore pressure as it equilibrates with the northern part of the field, where the pore pressure is relatively high due to the production restrictions in the Loppersum clusters. Compared to the base-case of continued depletion (case A in Figure 2.2), GPM can lead to a reduced depletion (case B), to a no-depletion (case C), or to an increase in pore fluid pressure (case D). These cases may vary in space and time across the field, from far-field unfaulted rock to fault gouge and to the rock near the injector wells. Assuming a causal relation between depletion-induced compaction and seismicity [5], there is little doubt that cases B and C will reduce seismicity compared to case A (although gas production rates and ultimate recovery (UR) will be lower in cases B and C than in case A). But what about case D? Will an increase in pore pressure have no measurable effect on induced seismicity, or will it decrease or perhaps even increase seismicity? This question must be answered for a safe and effective implementation of GPM.

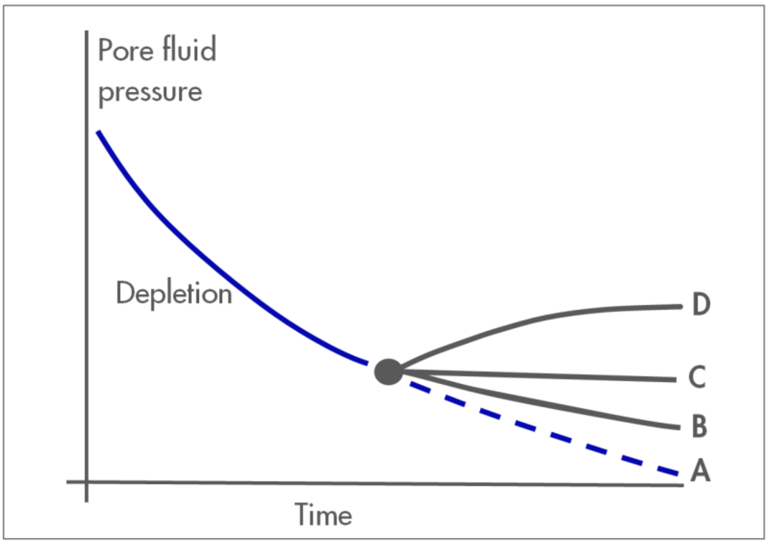

Figure 2.2: Cartoon showing the possible effects of GPM on the pore pressure at any given part of the field, including the near-wellbore area: A similar or lower depletion as without GPM (case A and B), no further depletion (case C) or an increase in pore pressure (case D).

This chapter shows geomechanical work performed to analyse and describe the possible effects of case D, an increase in pore pressure in the depleted Groningen field, whereas for further discussion on compaction-induced seismicity, the reader is referred to [4] and [5]. We first list observations from underground gas storage (UGS) sites in the Netherlands (section 2.2) and from the literature on injection-induced seismicity (section 2.3). Next, we introduce the concept of reservoir stress path, and present a mechanism-based model (one-dimensional Mohr-Coulomb, 1D MC) to predict the onset of fault slip (section 2.4). Despite its apparent potential to predict the effects of GPM on induced seismicity, there are some serious limitations to 1D MC models that will be explained in section 2.5. Sections 2.6 and 2.7 present a parallel approach to gain more insight in the geomechanics of GPM, based on two-dimensional (2D) Mohr-Coulomb modelling with more realistic geology and rock physics than in 1D MC, and gathering data in a field injection test. Section 2.8 summarises our current view on the status of geomechanical understanding for application to GPM in the Groningen field.

2.2. Underground Gas Storage

Underground gas storage (UGS) involves injection of natural gas in a depleted hydrocarbon reservoir. The Dutch UGS sites in the Rotliegend sandstone are of interest as an analogue to GPM in the Groningen field. Although these fields are smaller in size than the Groningen field, the reservoir rocks have the same geologic age (Permian Rotliegend sandstone) and are also cut by many large faults. Most importantly, the pore pressure changes during UGS are > 100 bar (Table 2.1) and should thus bring about similar or even higher compaction and dilation (volume decrease and increase, respectively) and stress changes to faults and reservoir rock as during GPM, see Nagelhout and Roest (1997 [7]). Importantly, injection at UGS sites in the north of the Netherlands did not give rise to large earthquakes like the one in Huizinge with M_l 3.6; see Table 2.1 based on data compiled by TNO [3]. The largest injection-induced earthquake during UGS in the Netherlands was an M_l of 1.05 and occurred in 1999 in the Norg field at a pore pressure of 309 bar, after it was increased by about 125 bar above the pore pressure of the depleted field (about 185 bar) to values just 20 bar below the virgin pore pressure of 328 bar [3]; see Figure 2.3 and Table 2.1.

Table 2.1: Observations on seismicity in three cases of gas injection in depleted reservoirs (underground gas storage, UGS) in the northern part of the Netherlands based on data by TNO [3].

Case	Magnitude on Richter scale (M_l)	Date	Depletion or injection	Virgin pore pressure (bar)	Depleted pore pressure * (bar)	Pore press. at seismic event bar)	Pore press. below virgin (bar)	Pore press. above max. depletion (bar)	Unload/load cycle of event
Norg	1.5	1993		328		245	83	-	First depletion
	1.05	1999	Injection	328	180 to 190 **	309	19	119 to 129 **	First injection
Grijpskerk	1.3	1997	Depletion	392		280	112	-	First depletion
	1.5	2015	Depletion	392	180	270	122	90	14th depletion
Bergermeer	3 to 3.5	1994 (2 events)	Depletion	228		50	178	35	First depletion
	3 to 3.5	2001 (2 events)	Depletion	228		25	203	10	First depletion
	0.7	2013	Depl./Inj.	228	15	Recorded with downhole micro-seismic array: tens of tremors			

*) Only listed when the seismic event occurred during the injection phase or during pore pressure cycling during UGS operations
*) Depending on the pore presure data used: Two sets of data falling in two pore pressure ranges

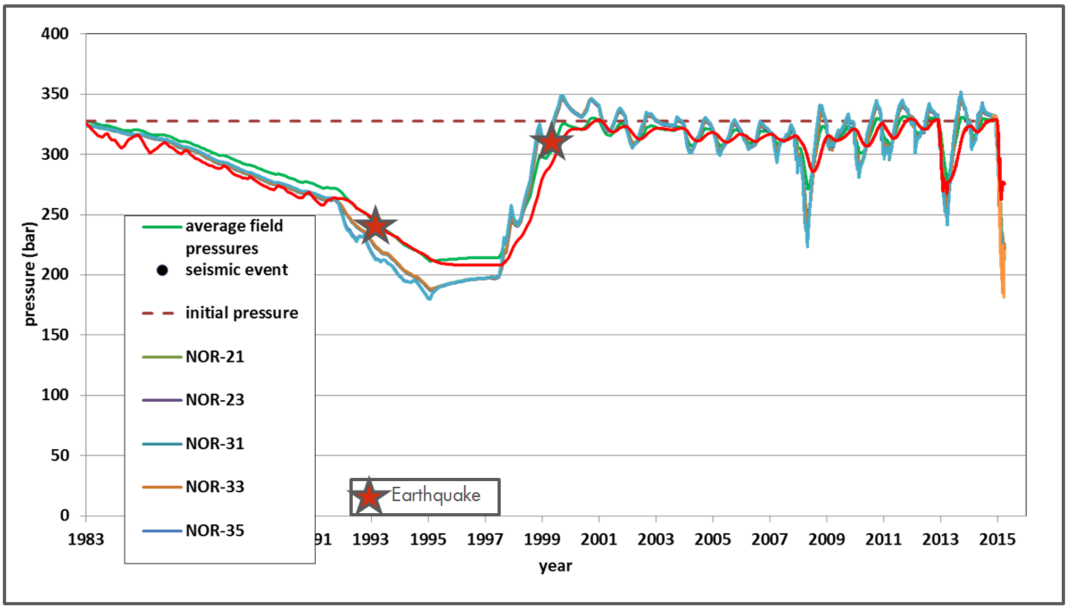

Figure 2.3: Pore pressure evolution in the Norg gas field, about 30 km southeast of the Groningen field [3]. The first stage (up to 1995) shows pressure evolution during primary depletion of the field, the second part shows pressure evolution during underground gas storage operations. The asterisks indicate the occurrence of an earthquake larger than M_l 1. Note the tens of bar increase in pore pressure (above

the level of maximum depletion) before the second earthquake (the one during injection) occurred.

Of interest is also the Bergermeer UGS, in the province of Noord-Holland. In 1994 and 2001, during primary depletion of this reservoir, four seismic events were recorded with magnitudes varying between M_l of 3.0 and 3.5, so of only slightly lower magnitude than the Huizinge earthquake of M_l 3.6. During injection of gas, the pore pressure increased by a few tens of bar above the pore pressure in the depleted field (25 bar). Many small earthquakes in the bandwidth M_l -3.5 to-1.5 (microseismicity) were recorded when the pore pressure was increased by up to 25 bar; 14 were larger than M_l –1.5 and three were larger than –0.5 M_l. The largest seismic event recorded during injection of gas was a 0.7-Ml seismic event (Oct. 2013), interpreted to be located close to the central fault [13]. Therefore, these are tremors rather than large earthquakes.

In summary, UGS data from three Dutch fields do not indicate large (e.g. M_l > 1.5) earthquakes during gas injection, although the pore pressure was increased by 90 to 129 bar after depletion of 150 to 200 bar.

2.3. Literature on Injection-Induced Seismicity

There are no documented case studies on the geomechanical effects of large-scale multi-year gas injection like GPM would require. However, injection-induced seismicity has been recorded, studied, and modelled on fluid-waste disposal, EOR schemes, water-flooding (secondary HC recovery), CO_2/gas storage, geothermal systems, and hydraulic fracturing (for reviews see Ellsworth 2013 [21], IEAGHG report 2013 [22], McGarr 2014 [14], TNO 2014 [12]). Table 2.2 summarises the number of injection wells and fields with seismic events M_l > 2 and maximum magnitudes reported in literature, compiled by TNO [12].

Table 2.2: Data from database on worldwide injection-induced seismicity [12].

Operation	Number of wells or sites	Number of wells/sites with magnitudes M>2	Total volume injected (m^3)	Pore pressure change (MPa)	Mmax
Hydraulic fracturing	1,000,000's wells	5	100-10,000	>S_{hmin}	3.8
EGS	10's-100 sites	10	1,000 – 100,000	+ 1 – 60	4.4
EOR/EGR	~120,000 wells (US alone)	22	10,000 – 10^8	+ 1 – 50 (lower P0 due to depletion)	5.7
Waste water injection	~30,000 wells (US alone)	16	1,000 – 1,000,000	+ve 1 – 20	5.7
Geothermal (conventional)	500-600 plants worldwide	15	10^6 - 10^9	-ve 1 - 10's reinjection: +ve low P	6.6
CO_2-storage	1-10's fields	0			0.8

There are very few papers with useful information on the mechanism of injection-induced fault slip and seismicity in depleted hydrocarbon reservoirs. Most papers are descriptive (case studies) and lack the field data or experimental data to make models. Though every case has a different structural geology, pore pressure, total stress state, and operational context, there are some learnings to be captured from the literature (see also [12]):

1. There are many cases in which fluid injection in reservoirs did not induce seismicity.
2. There is general agreement in the literature that injection-induced seismicity is triggered by an increase of pore pressure within the faults (above virgin pore pressure or above values after

depletion) and the associated reduction of effective normal stresses on the faults. In addition, there will be a change, and probably an increase, in the shear stress, but how this occurs as a function of the injection-induced deformation and dilation of the reservoir and fault gouge is unclear.

3. For the majority of the field cases of induced seismicity described worldwide, seismicity is interpreted to be related to an increase in pressure above the original reservoir pressure, adversely affecting fault stability.
4. Injection of a cold fluid in a relatively warm reservoir can also trigger seismicity, and this will depend on the temperature, type of fluid, amounts and rates of injection and on the distance of injection to critically stressed faults.
5. Four cases are listed by TNO [12] of depleted reservoirs in which a delay of years occurred between onset of injection and first seismic activity. Perhaps these faults were not critically stressed, or pore pressure diffusion occurred, or other effects like those described in Hettema et al. (2002) [26], describing delay effects between depletion and reservoir-compaction-induced subsidence.
6. There are also field cases in which seismicity happened after the shut-in of the injection well.
7. Injection-induced seismicity is sometimes triggered on previously undetected geologic faults (for recent examples, see Stabile et al. 2014 [24], Guglielmi et al. 2014 [25]).

There is no information in the literature to design "safe injection ranges" based solely on depletion- and injection-induced pore pressure changes. This is no surprise, given the complexity of induced seismicity and lack of field data. The literature indicates that the highest risk for injection-induced seismicity in a depleted reservoir often occurs with faults that are critically stressed because of 1) geological conditions, like in an over-pressured reservoir with low effective normal stresses acting on the faults, or because 2) depletion-induced compaction or injection occurred, which led to differential strain across the fault and/or brought the stress state at the faults closer to shear failure. Therefore, caution is required for pressure maintenance through injection in the heavily depleted Groningen reservoir, as the hundreds of earthquakes over the past decades indicate that many faults in Groningen are indeed critically stressed, at least over some part of their surface. Even a small (a few bars) increase in pore pressure perturbing the stress field at these "hot spots" could possibly cause earthquakes, releasing large amounts of energy accumulated due to the depletion-induced reservoir compaction [11]. Having said this, it should be noted that injection-induced-seismicity in Groningen is *a hypothesis*: it has not been observed yet, and there are no papers that describe this scenario for a reservoir like Groningen.

2.4. 1D Geomechanical Modelling

Bourne et al. (2014) [11] made a calibrated model to predict compaction-induced seismicity in Groningen. The model is strictly speaking only valid for depletion-induced compaction, and cannot be applied to predict the effect of injection on seismicity without re-calibration to field data collected during such an injection. With neither the Dutch UGS examples nor the literature providing empirical or mechanism-based models previously used for injection-induced seismicity, we start by investigating how the stress state at a typical Groningen fault may change during depletion of a few hundred bar followed by an injection-induced increase in pore pressure of a few tens of bar. This is done with a 1D analytical geomechanical tool for MC frictional slip [17], [15], [38], where the input is the pre-production stress state and pore pressure, the stress path during depletion and injection, the mechanical rock properties, and the orientation of the fault. The output of the model is the shear capacity utilisation (SCU), which is a number between zero and one indicating the tendency (likelihood) of fault slip. We will briefly explain the stress path and SCU here.

The concept of stress path in reservoir mechanics is based on the observation in tens of papers that reservoir depletion (ΔP_p) is accompanied by a reduction in minimum total principal stress (S_3), see e.g. Teufel et al. (1991) [20], Addis et al. (1996) [19], Sayers and Schutjens (2007) [18], and Segura et al. (2011) [30]. Defining the horizontal stress path coefficient[2] during depletion as

$$\gamma_{hor,depl} = \Delta S_3/\Delta P_p = \Delta S_h/\Delta P_p \ ,$$

most values for $\gamma_{hor,depl}$ range from 0.4 to 0.9, reflecting the impact of geology variation on reservoir total stress response to depletion. Interestingly, $\gamma_{hor,depl}$ is often fairly constant within a given reservoir, see e.g. Teufel et al. 1991 [20]. Figure 2.4 shows data on the stress path for the Groningen field from Van Eijs and Valencia (2015) [29], indicating a best-estimate $\gamma_{hor,depl}$ of 0.64 with a 95%-confidence interval between 0.42 and 0.86. Information from laboratory experiments on Groningen core points to $\gamma_{hor,depl}$ in the range 0.7 to 0.9. We used $\gamma_{hor,depl}$ = 0.7 in most simulations.

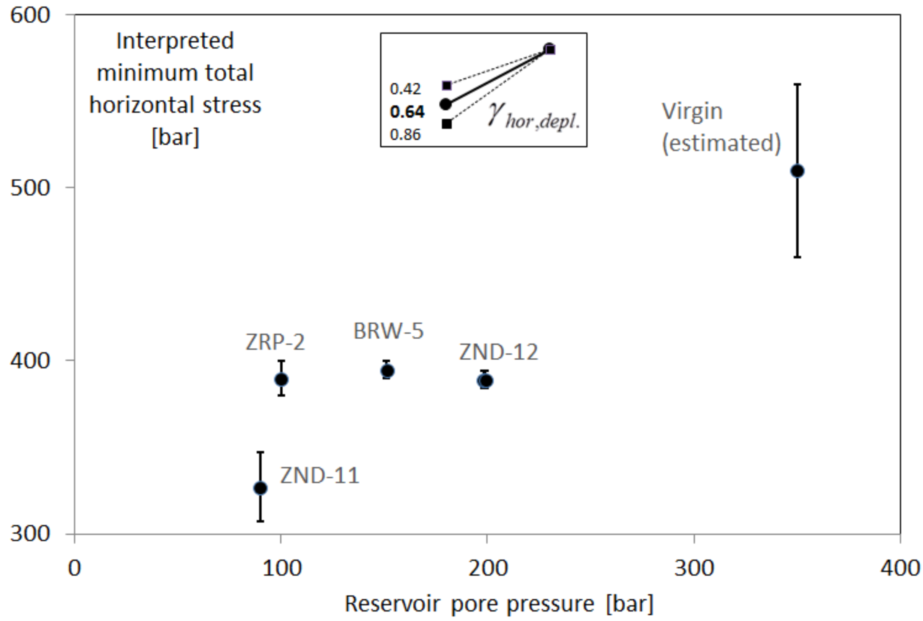

Figure 2.4: Field data for Groningen suggesting a reduction of interpreted minimum total horizontal stress with depletion, leading to a $\gamma_{hor,depl}$ of 0.64 with a 95% confidence interval from 0.42 to 0.86 (Van Eijs and Valencia 2015 [29]).

So we have some insight on stress path during depletion. But unfortunately, papers with field data on the stress path coefficient during an injection-induced pore pressure increase,

$$\gamma_{hor,inj} = \Delta S_3/\Delta P_p = \Delta S_h/\Delta P_p \ ,$$

are very scarce. Santarelli et al. (1998) [44] estimate $\gamma_{hor,inj}$ in a North Sea field to be between zero and 0.1, and his paper remains the only published source of $\gamma_{hor,inj}$ to date. There is general agreement in the literature that $\gamma_{hor,inj}$ will be smaller than $\gamma_{hor,depl}$ since part of the depletion-induced deformation (and thus part of the S_3-reduction) will probably not “bounce back” should the original pore pressure be restored. This stress-path irreversibility occurs because energy has been dissipated during depletion through plastic deformation of the rock, producing permanent (not-

[2] For a normal faulting regime like Groningen, we will assume here that the minimum total principal stress (S_3) equals the minimum total horizontal stress (S_h).

recoverable) microstructural changes like grain cracking, grain sliding, and grain rotation. These mechanisms increase the system entropy and produce heat via grain-to-grain contact friction.

In the 1D MC modelling for GPM, the effective normal stress (σ_n) and maximum shear stress (τ_{max}) is calculated at a planar fault dipping 70° to ENE 70°, which is typical of the orientation of many large faults in the Groningen field. The fault-dip direction is aligned with the average direction of the minimum total horizontal stress in the Groningen field (ENE 70° to WSW 250°). Starting from the virgin (pre-production) stress state in Groningen, scenarios for the stress path as indicated in Figure 2.5 are used. The brown and blue dots in Figure 2.6 indicate the σ_n-τ_{max} stress state for virgin conditions and after a depletion of 270 bar at a stress path $\gamma_{hor,depl}$ of 0.7, respectively. Note that the dots plot on Mohr circles, which present σ_n-τ_{max} combinations of all potential planar faults in the rock at this point in the reservoir (see Fjær et al. 2008 [17]). Also indicated in the plot is the MC shear failure line, controlled by cohesion (C_0) and angle of internal friction (ϕ). The distance of the σ_n-τ_{max} points (indicating the stress state on a fault) to the MC-line is a measure of the tendency of shear failure of the fault: The length of the vertical black line divided by the length of the vertical red line is a ratio called the Shear Capacity Utilisation (SCU). It ranges between zero, with no shear failure tendency, to 1, when the rock is at shear failure. Figure 2.6 shows that a 270-bar depletion increases the SCU from about 0.45 at virgin conditions to about 0.85 at a pore pressure of 80 bar. Note that depletion increases SCU on this particular Groningen-typical fault, and that some hypothetical fault planes dipping 45° to 60° are already at shear failure (A to A' on the blue "depleted" Mohr circle).

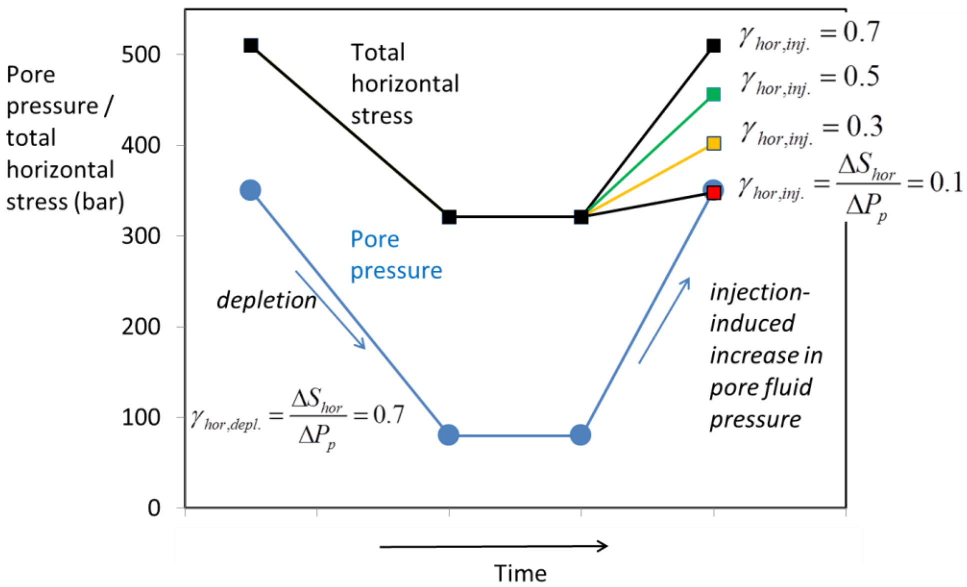

Figure 2.5: **Coupling between production/depletion-induced and injection-induced changes in pore pressure and the change in minimum total horizontal stress, captured in the stress path coefficients $\gamma_{hor,depl}$ and $\gamma_{hor,inj}$. Field data indicate that, typically, $\gamma_{hor,depl} > \gamma_{hor,inj}$. Note that $\gamma_{hor,depl}$ will be highest in the first depletion, and may be smaller in subsequent depletion-injection cycles.**

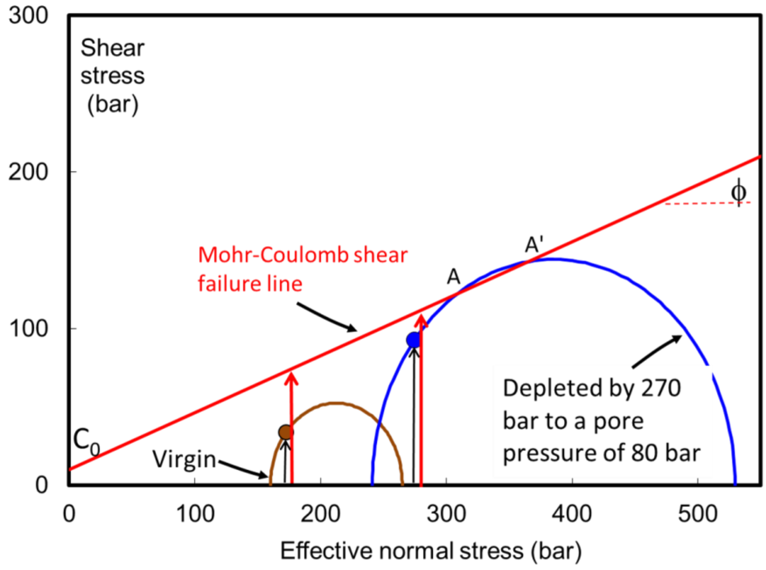

Figure 2.6: **Stress state in virgin and depleted Groningen reservoir rock (brown and blue Mohr circles, respectively) and at a Groningen-typical fault dipping 70° to SSE 160° (brown and blue circular symbols). The red line is the Mohr-Coulomb shear failure line. The length of the black vertical vector divided by the length of the red vector is the Shear Capacity Utilisation (SCU) factor, a measure of the likelihood of shear failure.**

Figure 2.7 shows stress paths during an injection-induced increase in pore fluid pressure of 40 bar, starting from the depleted value of 80 bar (blue dot) and using four stress path coefficient $\gamma_{hor,inj}$ of 0.7 (perfect stress-rebound), 0.5, 0.3, and 0.1 (as shown in Figure 2.5). Note that, for this model, injection along $\gamma_{hor,inj}$ of 0.5, 0.3, and 0.1 will increase the SCU. In contrast, the injection along $\gamma_{hor,inj}$ of 0.7 will produce no significant change in SCU (stress path vector near-parallel to the MC shear failure line). The smaller the $\gamma_{hor,inj}$, the stronger the SCU increase per unit increase in pore fluid pressure.

Depending on the virgin stress state, stress paths during depletion and injection, and rock mechanical parameters, there may be a range of relatively high $\gamma_{hor,inj}$ values in which the SCU actually decreases with increasing pore fluid pressure. Figure 2.8 shows the effects of depletion and injection on SCU in 1D MC simulations with Groningen-typical stress states and rock properties, again for a fault dipping 70° to 70° ENE. Starting with a depletion from 350 bar to 80 bar with $\gamma_{hor,depl}$ of 0.7 (point A in Figure 2.8), further depletion with $\gamma_{hor,depl}$ of 0.7 (towards point B) will increase the SCU. Should an injection-induced pore pressure increase from 80 bar (towards point C) occur with the same stress path $\gamma_{hor,inj}$ of 0.7, of course, the SCU would decrease. This occurs for all values of $\gamma_{hor,depl}$ in the green zone in Figure 2.8. But as stated above, it is likely that $\gamma_{hor,inj}$ is smaller than $\gamma_{hor,depl}$. For injection with $\gamma_{hor,inj}$ smaller than 0.54 (point D), the SCU actually increases with increasing pore fluid pressure (yellow and red zones).

Comparison with the SCU increase during a depletion from 80 bar to 40 bar (point E) thus reveals three stress path ranges during injection: For $\gamma_{hor,inj}$ values in the green zone ($\gamma_{hor,inj}$ from 0.70 to 0.54) in Figure 2.8), the SCU decreases with injection. For $\gamma_{hor,inj}$ values in the yellow zone (0.54 to 0.39), the SCU increases with injection, but the SCU increase per unit increase in pore pressure is lower than the SCU increase per unit depletion. Point F is the threshold $\gamma_{hor,inj}$. For $\gamma_{hor,inj}$ values in the red zone (0.39 to 0), the SCU increase per unit increase in pore pressure is higher than the SCU increase per unit depletion.

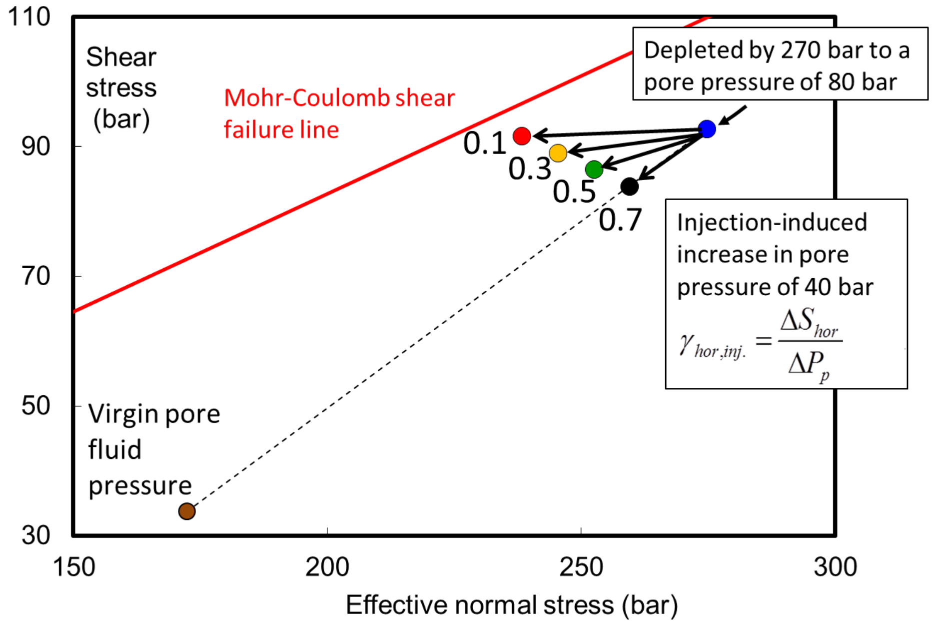

Figure 2.7: **Effect of an injection-induced increase in pore pressure on shear stress and effective normal stress for a horizontal stress path coefficient during injection ($\gamma_{hor,inj}$) in the range 0.1 to 0.7, following depletion from 350 bar to 80 bar at $\gamma_{hor,depl}$ of 0.7. Injection at a relatively low value of $\gamma_{hor,inj}$ leads to higher SCUs, i.e. to a higher tendency of shear failure, compared to the depleted state (blue closed circle).**

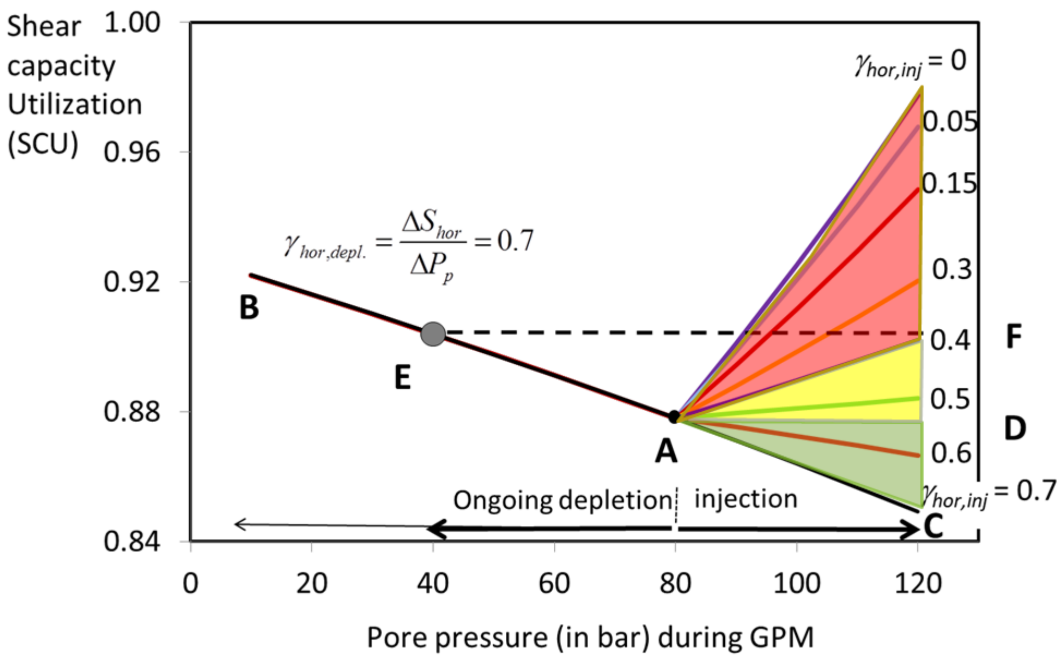

Figure 2.8: **Results from an analytical one-dimensional Mohr-Coulomb frictional slip model, comparing the effects of depletion at a horizontal stress path coefficient ($\gamma_{hor,depl}$) of 0.7 and injection under a horizontal stress path coefficient ($\gamma_{hor,inj}$) in the range 0 to 0.7. The influence of an injection-induced pore pressure increase on SCU strongly depends on $\gamma_{hor,inj}$: There are model-specific ranges of $\gamma_{hor,inj}$ where injec-**

tion reduces SCU overall (green zone), reduces SCU compared to a similar depletion (yellow zone), and increases SCU compared to a similar depletion (red zone).

It must be kept in mind that the model results shown in Figure 2.8 are for simulations with one particular set of input parameters. But qualitatively similar results are obtained if we vary them, with the three areas with $\gamma_{hor,inj}$ values in green, yellow and red zones appearing in all results, though with different combinations of $\gamma_{hor,inj}$. and SCU values. This contains a message with potentially important implications for fault slip during GPM-induced injection: there may be a range of $\gamma_{hor,inj}$ values where injection reduces the SCU, or at least reduces it compared to a similar pore pressure change due to depletion (green and yellow zones in Figure 2.8). A reducing SCU may lead to a reduction in the likelihood of induced seismicity. However, should the $\gamma_{hor,inj}$ values be very low (say, < 0.2), a pore pressure increase with GPM may be accompanied by a relatively large increase in SCU, and thus to an increase in seismic hazard compared to a similar pore pressure change during depletion. In any case, the 1D MC simulations suggest strong control of the stress path during injection on the fault slip, and this, in turn, may indicate control of the stress path on seismicity. Unfortunately, as stated above, there is only one paper on $\gamma_{hor,inj}$ with one datapoint. Furthermore, the validity of 1D MC simulations for the prediction of fault slip proper under depletion and injection needs to be critically reviewed.

2.5. Limitations of 1D Mohr-Coulomb Geomechanical Modelling

Although 1D MC simulations indicate the potential for GPM to reduce seismicity, there are some serious concerns.

First and foremost, stress-based models of fault slip tendency using 1D MC models predict fault slip in the Groningen field where it is not occurring. Figure 2.9a shows several of the 700 large Groningen faults, and Figure 2.9b shows their SCU value based on research by Van den Bogert et al. (2013a) [31]. Note that this model predicts seismicity in the centre of the field, but also at the edges of the field and in the Southern part (purple colours indicate faults with high SCU). And indeed, most strong seismicity has occurred in the central part, around the Loppersum area (Figure 2.9c), where there is a high compaction (Figure 2.9d). But in contrast with the model prediction, seismic activity has been relatively low at the edges of the field, and in the southern part. It requires a detailed 3D finite element geomechanical model with laterally varying mechanical properties and stresses to match the model to field data (see Sanz et al. 2015 [39]), and even then, the predictive capability of such an elaborate model to predict future earthquake is questioned (see below).

Secondly, there is a large uncertainty in the pre-production stress state, the orientation of the maximum total horizontal stress, and the stress path (see Van Eijs and Valencia, 2015 [29]). Also the mechanical rock properties in reservoir and fault zones will be heterogeneous (see e.g. Chang 2006 [33]; Crawford et al. 2010 [35]), and as a result, MC type stress-based models show a large uncertainty in the SCU (Figure 2.10).

Thirdly, 1D MC models use isotropic mechanical properties, and no distinction is made between reservoir and fault. Yet 2D finite-element simulations of frictional slip along faults reveal a strong variation of SCU along the fault in case the depleting reservoir is offset along the fault. Importantly, the SCU obtained in 1D MC analyses, which corresponds to the no-fault-offset case, is not the most conservative (i.e. high SCU) geologic scenario, but the most "optimistic" one, i.e. predicting fault slip only after a relatively high depletion (Figure 2.11) compared to slip at faults offsetting the depleting reservoir.

Fourth, a 1D MC model does not take into account any injection-induced cooling effects and associated total stress reduction, or time-dependent fault gouge pressure changes.

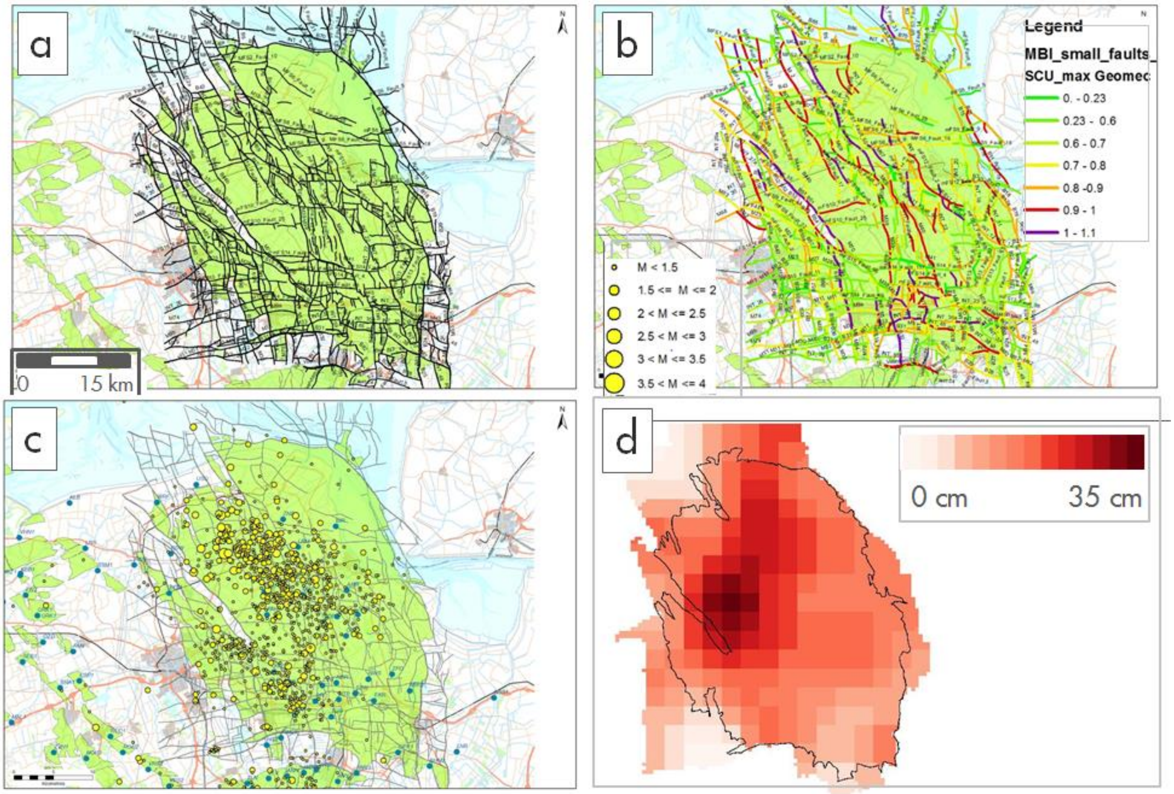

Figure 2.9: A set of large faults in the Groningen field mapped based on seismic data (a) with SCU indicated (b, van den Bogert et al. 2013a [31]). The amount of earthquakes recorded through mid-October 2015 (c) agrees with a zone of high SCU, but other zones of high SCU in (b) did not experience many earthquakes, like at the edges of the field and the southern part. The in-situ compaction strain inverted from subsidence (Bourne et al. 2014, [11]) is a better indicator for seismicity (d).

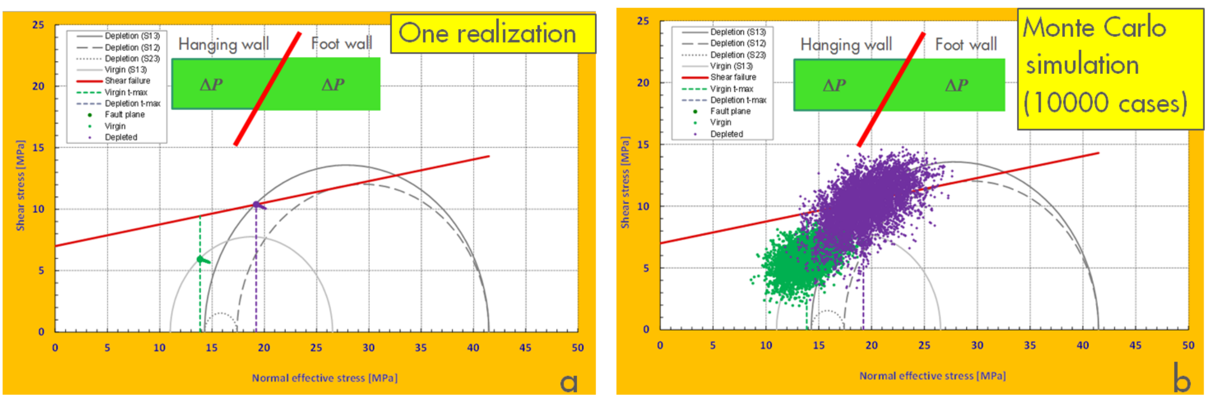

Figure 2.10: Uncertainty in the input parameters of frictional slip models like the 1D Mohr-Coulomb model produces significant uncertainty in the prediction of fault slip. These results in Figure 2.10b represent 10,000 simulations in which the magnitude of eight input parameters was varied: the initial stress state ($S_{vertical}$, $S_{h,max}$, $S_{h,min}$, P_p), orientation $S_{h,max}$, fault dip, fault azimuth, and the stress path coefficient during depletion ($\gamma_{hor,depl}$), the latter taken here as 0.78 with a standard deviation of 0.08.

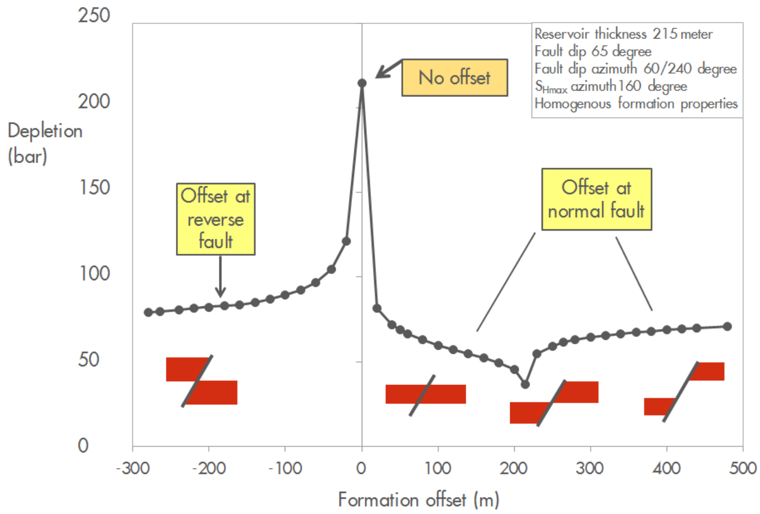

Figure 2.11: Depletion to reach shear failure as a function of offset of depleting reservoir along a normal and reverse fault. These 2D finite-element frictional slip models show a strong effect of fault offset on the maximum SCU along the fault. Note that the 1D Mohr-Coulomb model in which fault slip is predicted on a fault without offset is not the most conservative model, but rather, the most optimistic (fault-slip resistant).

Fifth, 1D stress-based models only describe the onset of fault slip, and essentially have two outcomes: not-slipping or slipping. Such models are unable to describe the distribution of fault slip parameters along the fault, or the details of the fault-slip mechanism and how it evolves with fault slip or time. This is also a limitation of the work of Sanz et al. (2015) [39]. Knowing these limitations of MC-type modelling, we exert caution in over-interpreting the results of 1D MC models, and we will not use such models to predict injection-induced seismicity.

Our further work was directed at providing geomechanical input to GPM in two ways:

1. via more sophisticated mechanism-based models for pore pressure increase and its effect on fault stability, and
2. via feasibility analysis of a field injection test to accurately measure the effects of a well-controlled pore pressure increase on seismicity, including gathering high-quality field data to construct and calibrate new geomechanical models for injection-induced fault slip.

2.6. Frictional-slip Modelling: A More Sophisticated 2D Model

More sophisticated 2D finite-elements models have been constructed recently, based on a MC constitutive law describing the relation between local stress and local strain, but with

1. a fault that offsets the depleting reservoir,
2. non-uniform pore pressure changing in reservoir and fault gouge as a function of injection pressure and time,
3. homogeneous isotropic fault slip properties, and
4. plastic deformation when SCU > 1 with associated total stress redistribution (van den Bogert and van Eijs 2013b [32], Van den Bogert 2015, TNO 2015b [28]).

Next to SCU, the model calculates the length of the fault that is slipping (L_s), i.e. where SCU ≥ 1, and the maximum slip distance (S_d) along the slip part (Figure 2.12). The results obtained with the new models confirm the result shown in Figure 2.13: fault offset, probably acerbated by the introduction of plasticity, leads to a complex interplay between fault slip, near-fault reservoir and fault gouge deformation, and total stress change. SCU, L_s, and S_d vary along the fault plane.

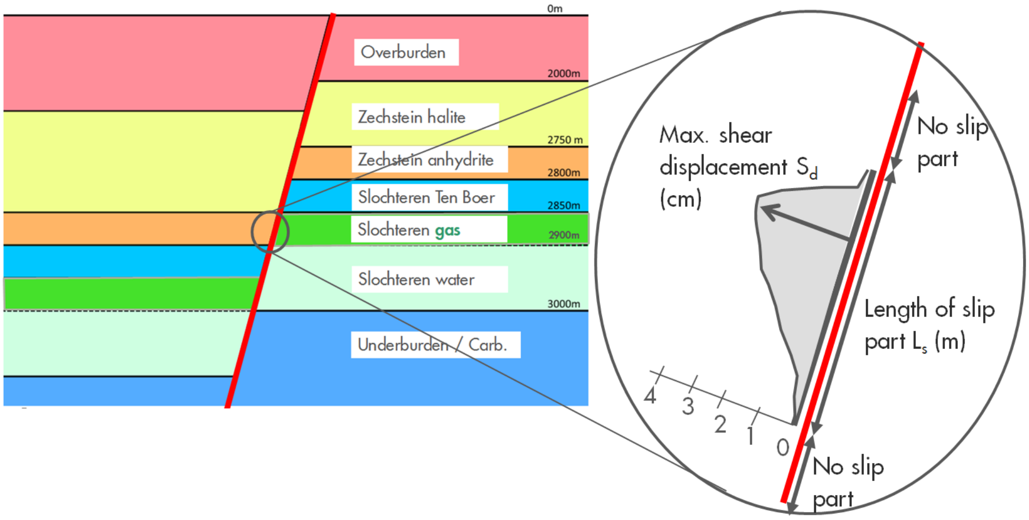

Figure 2.12: Introducing two new parameters in frictional slip models: the length of the fault that is slipping (L_s), i.e. where SCU ≥ 1, and the maximum slip distance (S_d) along the slip part.

The models for a Groningen-typical fault offset of 100 m indicate a strong dependence of fault slip response during injection on the stress path coefficient ($\gamma_{hor,inj}$) in the fault gouge: following a depletion of 280 bar from an initial 350 bar to 70 bar with a stress path coefficient during depletion of $\gamma_{hor,depl}$ 0.68, the pore pressure was increased by 50 bar at a constant stress path during injection of $\gamma_{hor,inj}$ of 0.68 (base case), 0.51, 0.3, and 0.07 [13]. The result of this sensitivity analysis is shown in Figure 2.13 and Figure 2.14.

With the 280-bar depletion creating a fault slip length (L_s) of 117 m (not shown here), injection by 50 bar with a $\gamma_{hor,inj}$ of 0.07 increases L_s to 143 m. This is 14 m more than the 129 m, which would have occurred during a further depletion of 50 bar. Coincidentally, injection by 50 bar with a $\gamma_{hor,inj}$ of 0.3 also increases L_s to 129 m. In contrast, injection by 50 bar with a $\gamma_{hor,inj}$ of 0.51 decreases L_s from 117 m to 63 m. The maximum slip distance (S_d) shows a similar pattern: Compared to the S_d of 4.6 cm during ongoing depletion of 50 bar, up by 1.6 cm from the S_d of 2.8 cm obtained after the original 270 bar depletion, injection by 50 bar with $\gamma_{hor,inj}$ of 0.07, 0.3, and 0.57 leads to a an S_d of 5.6, 3.9, and 0 cm, respectively. Note that, just like the fault slip length L_d, S_d during injection reduces with increasing $\gamma_{hor,inj}$ (Figure 2.14).

If slip patch length and maximum slip distance are measures for induced seismicity, these models point out that in some scenarios, more seismicity can occur when compared to a further depletion case, but in other scenarios, there can be less seismicity. The likelihood of these scenarios is difficult to predict but from rock mechanical observations in the laboratory and from geodetic measurement above the Norg UGS, we know that some part of the compaction is irreversible, and therefore a lower value for the $\gamma_{hor,inj}$ is expected than the $\gamma_{hor,depl}$ of around 0.65 (Figure 2.4).

The new models were also used to investigate the effect of a temperature reduction during injection [13]. Injection of relatively cold N_2 gas during GPM will cool the reservoir rock and cause it to shrink, thereby reducing the total stresses that are acting on the reservoir rock. This cooled zone and the larger zone of reduced total stress gradually extend outwards from the injector well as the gas injection progresses, eventually reaching the fault zone where the injection-induced increase in pore pressure has already affected the total stresses via the poro-elastic effect (we neglect plasticity here, assuming SCU < 1). The first set of simulations reveal that the injection-induced cooling of the fault gouge has a strong effect on fault slip stability, possibly changing the total stress state and thus the SCU more than the poro-elastic effect. In the simulation results shown in Figure 2.15, the SCU at the fault zone increases by about 0.1 if the influence of temperature is accounted for, while the pore-pressure-increase alone has a negligible effect. So temperature must be accounted for, which is another reason why the 1D MC models shown above should be regarded with caution, and more sophisticated geomechanical modelling, including pore pressure diffusion and temperature effects, is necessary.

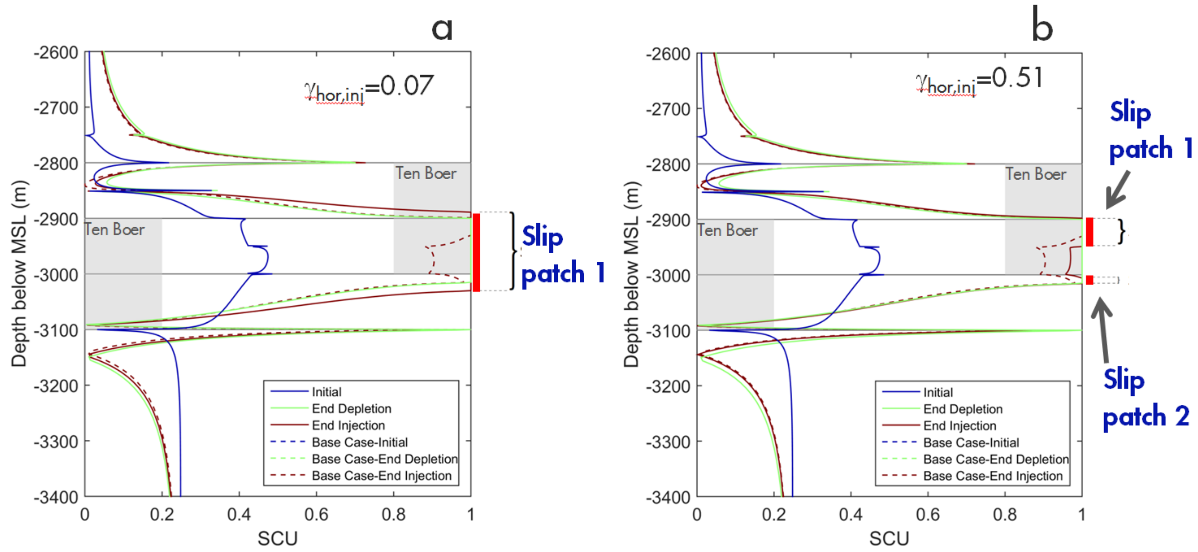

Figure 2.13: **Overview of shear capacity utilisation (SCU) for a horizontal stress path coefficient ($\gamma_{hor,inj}$) of 0.07 (left) and 0.51 (right). Dashed lines represent SCU for the base case, which is for a $\gamma_{hor,inj}$ of 0.68. Note the single and relatively large slip patch in the simulation with $\gamma_{hor,inj}$ of 0.07 compared to the one with $\gamma_{hor,inj}$ of 0.51, which shows two slip patches that are, in total, of a smaller length than in the simulation with $\gamma_{hor,inj}$ of 0.07. The light grey blocks indicate the position of the reservoir (Slochteren gas and water) in the hanging wall and footwall [13].**

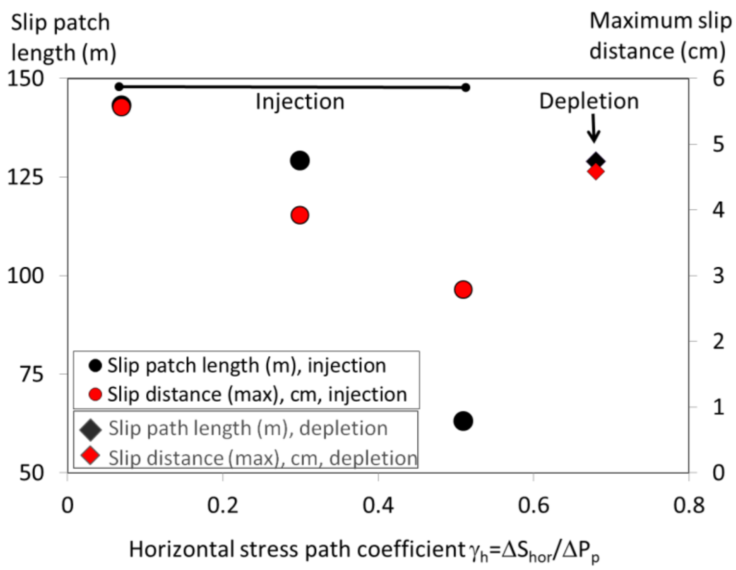

Figure 2.14: **Slip patch length (L_s) and maximum slip distance (S_d) as a function of stress path coefficient $\gamma_{hor,inj}$ during injection (circle-data) and depletion (square-data) of 50 bar in the 2D finite-element simulations of fault slip offsetting the reservoir by 100 m (plot based, in part, on data in Figure 2.13 and published in TNO 2015b [13]). Note that compared to the depletion case, values for L_s and S_d are relatively low at relatively high values for the $\gamma_{hor,inj}$. This confirms that, perhaps, injection under high $\gamma_{hor,inj}$ can reduce seismicity.**

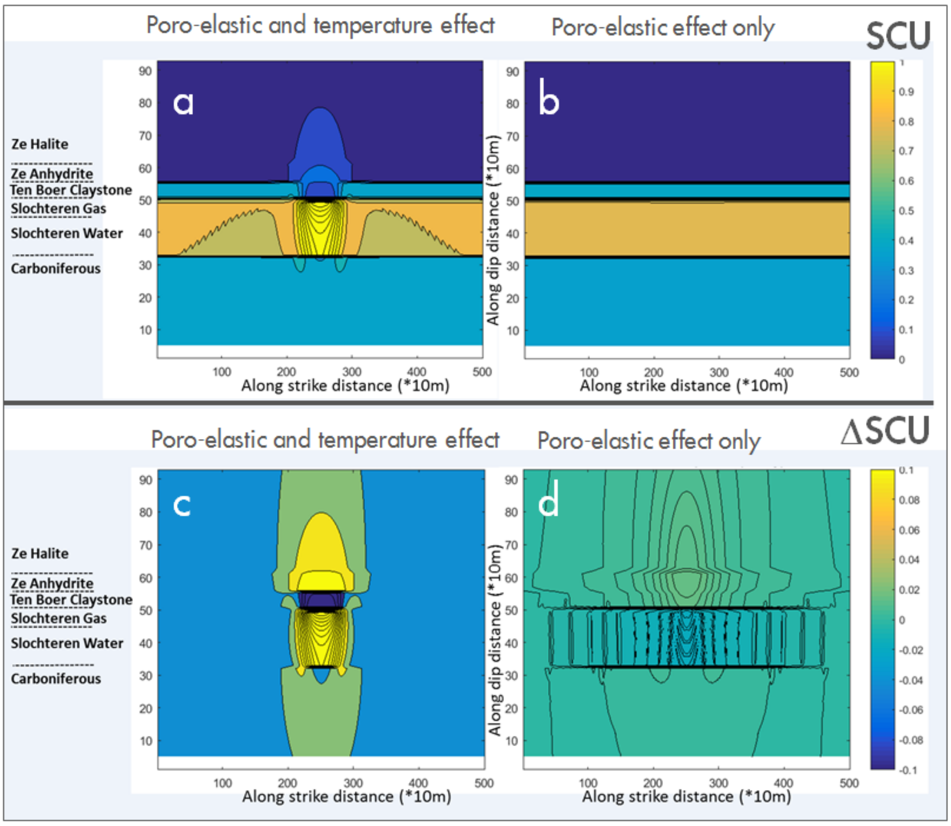

Figure 2.15: **Effect of injection-induced cooling on SCU along a vertical plane at a distance of 300 m from the injector well. Injection pressure is 165 bar, some 95 bar above the maximum depletion of 70 bar. This result is for a time 20 years after start of injection. Figures a and b give the absolute value of SCU for the case of injection with temperature and without temperature effect, respectively. Figures c and d give the change in SCU compared to the SCU after depletion to 70 bar, again for the case of injection with temperature and without temperature effect, respectively. Initial reservoir temperature is 94 °C; initial nitrogen temperature is 10 °C. Note the strong effect of injection-induced temperature on SCU, which is caused by a cooling-induced reduction in total stress state at the faults. Poisson's ratio of the reservoir rock is 0.20, the horizontal stress path coefficient is about 0.70, Young's modulus is 15 GPa, and the coefficient of thermal expansion is 10^{-5} °C^{-1}. For detailed information, see TNO (2015b) [13].**

The International Energy Agency recently published a review on fault geomechanical stability during pressure build-up (IEAGHG 2015, [38]). Their key conclusion is that "the Mohr Coulomb failure criterion is the major stress-strength relationship employed for stability analysis of faults during injection of fluids such as CO_2, or depletion of hydrocarbons. Analytical methods combined with the numerical solutions provide the best approach for assessing geomechanical stability of faults". Because of the more realistic geology and rock mechanics in the new set of frictional-slip models, we believe that the results are more representative of an injection-induced fault slip during GPM than the 1D models shown in Figure 2.7 and Figure 2.8. The new models present a mechanistic basis to the interpretation that injection can indeed reduce the tendency for fault slip, reduce the fault slip length and reduce the maximum distance of fault slip, provided the stress path coefficient is relatively high, i.e. similar to, or just slightly lower than, the one during depletion. Yet, despite this insight, the input parameters still have a great uncertainty, and field data to calibrate the new models are not available. In addition, there is the additional complexity of the injection-induced temperature change affecting the total stress state, and thus SCU, L_s, and S_d. This is where the idea for a field injection test comes in. Next to model construction and elaborate sensitivity analyses, what is also required is a field injection test to measure what is actually happening at the Groningen faults during gas injection for pressure maintenance.

2.7. Field Injection Test

It is presently unknown whether increasing the pore pressure during GPM will produce less, more, or a similar rate of earthquakes (amount and maximum magnitude over a given time) than is occurring now under the slow-depletion conditions in the Groningen field. A controlled injection of N_2 or Groningen gas into an area of the field close to a fault where a recent earthquake occurred can probably help to gain insight which of these hypotheses is the most likely.

The first aim of such a field injection test is to de-risk GPM by gathering seismicity data and conducting statistical analyses to establish whether or not changing the measured in-situ pore pressure in a controlled way (ramped up by a few bar to a few tens of bar over a period of, say, three months) changes the amount of earthquakes recorded over a given time period. Clearly, the seismic events recorded during and after the pore pressure increase must be different from before the pore pressure change, and this and other data (like the change in total stress or the in-situ strain) must be unambiguous in being due to the injection-induced (controlled) pore pressure increase, and not because of another effect. The second aim of the field test is to gather data to understand the detailed mechanics of the reservoir during injection: Will the reservoir around the injector well and at the fault expand vertically (dilation), and will the minimum total principal (horizontal) stress increase as a function of the increasing pore pressure, allowing an in-situ measurement of $\gamma_{hor,inj}$? Achieving both aims requires extensive instrumentation of injector and observations wells to acquire a combination of geophysical (acoustic) data and rock mechanics data (Figure 2.16).

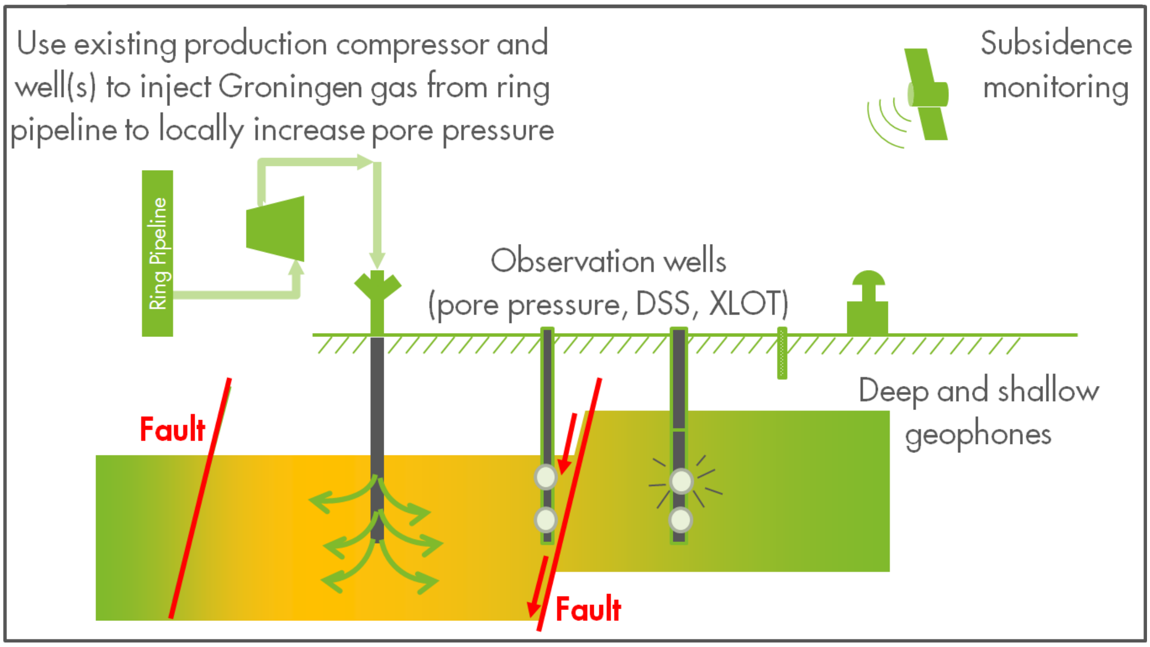

Figure 2.16: Schematic of field injection test. For optimal learning, instrumenting a dedicated observation well should be considered to confirm the injection-induced increase in pore pressure at nearby fault(s) around which induced seismicity has occurred.

Key to a successful field test is the ability to get meaningful information for GPM from the field data with acceptable safety risks, providing value-of-information at a fraction of the total GPM project investment, and over a reasonable time span. We will briefly address here the concerns on safety and on gaining meaningful information from a field injection test. Regarding safety, indeed, if the Groningen faults in the injection area are critically stressed (i.e. at the verge of slipping), then, theoretically, a small (few-bar) pore pressure increase could lead to fault slip and seismicity. We do not know how big such an earthquake would be, and how many of such large seismic events would occur during and after a field injection test. This is certainly a major point of concern, but a few points must be kept in mind. Firstly, there are no data or models in Shell nor in the open literature indicating that injection-induced seismicity will occur in a field like Groningen. Secondly, regarding the ability of a "controlled injection", fluid-flow models based on the latest static and dynamic reservoir model of Groningen show that a pore pressure increase of tens of bar in a field test requires several bcm of gas injection. This will take months and thus provide ample time to carefully measure the pore pressure increase in the injector and (as we propose) in a dedicated observation well close to the fault, and if necessary, control it via the bottomhole flowing pressure at the injector well.

On obtaining meaningful information from a field test, there is the rightful concern of representativeness of the findings in just one field test done in this large Groningen field. However, dealing with the in-field geologic variability and shortage of field data is an essential part of any geoscience modelling, and thus also of reservoir mechanics. We will only know the degree of heterogeneity of Groningen reservoir parameters if we measure them. The applicability of information from the field test data for other locations in the Groningen field depends on the depth of understanding of the deformation mechanism (physics, thermodynamics) at the faults, and on the lateral variation in geological structure and rock mechanical properties across the field. The results may be ambiguous or hard to use for model construction. However, there is an opportunity to learn and increase the knowledge of poorly understood mechanism-based geomechanical effects of gas injection. Imagine, for example, that the field injection test leads to a reduced induced seismicity complemented by relatively high values of in-situ-measured $\gamma_{hor,inj}$. One would then gain more confidence in models like the one shown in Figure 2.13. From a geomechanical perspective, if the rock mechanical properties, stress state, and stress changes vary gradually across the field and within bounds captured by the model, there is no reason why a mechanism-based model could not be applied across the field [3]. Field data are essential to construct and calibrate such a model to predict the geomechanical effects of GPM operations in the Groningen field.

Chapter 5 contains more details on the field injection test, focusing on the test scope, on the modification of the cluster where the injection test will occur, and on the statistical analysis of the field data.

2.8. Summary

There is insufficient data in the literature to make an empirical or mechanism-based model for injection-induced seismicity during GPM: There are no papers with systematic field-injection tests, and geological, petrophysical, and operational conditions vary greatly between the various cases. Data from UGS sites in the northern Netherlands show only one case of fairly large injection-induced seismicity (Norg, with magnitude 1.05 on the Richter scale) but do not point to

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3 For an analogy, significant and fast (within years) technical progress was made in the understanding of shear-enhanced compaction and compaction bands via a combination of theoretical analysis, experimental rock deformation work, and field data (see Wong et al. 1992 [40], 1999 [27], Knipe et al. 1998 [36], and Lewis and Couples 2007 [41]).

many large earthquakes during the tens of bar pore pressure increase above maximum depletion levels. The UGS in the Bergermeer field is of interest as well, because during its depletion by more than 200 bar, there have been several strong earthquakes (M_l of 3.0 to 3.5), see Table 2.1 and Table 2.2, so we can safely assume that some parts of the Bergermeer faults are critically stressed. Nevertheless, during the subsequent injection with a pore pressure increase of a few bar to tens of bar, only very small earthquakes (microseismicity, or tremors) were observed. In addition, a review of the open-literature papers indicates that, in most cases, induced seismicity is only observed when injection pressures exceed virgin (pre-production) pore pressures. Taken together, information from analogue fields and global injection cases does not point to strong earthquakes after injection in depleted reservoirs, but rather suggests that seismicity may be low or absent during injection, or only occurs when injection pressures approach virgin pressures. But as always, one must recall that every field is different, and predictions based on analogue fields remain highly speculative until proven by field data.

Most theoretical and review papers on injection-induced seismicity refer to frictional slip as the underlying mechanism of injection-induced seismicity but no detailed modelling work is presented, probably for two main reasons: The physics of injection-induced seismicity is very complex, and there is a lack of systematically collected field data. In addition, classical (no-offset) MC type frictional-slip models have a number of serious drawbacks. Our current modelling approach to injection-induced fault slip is in line with the recent recommendations of IEAGHG (2015) [38] to combine analytical and numerical methods, and aim for realistic geology; our models do contain Groningen-typical structural geology with offset along the faults, pore pressure diffusion, plasticity, and temperature effects. Rupture modelling and post-failure fault stabilisation analyses are ongoing.

Given the present situation of no available valid and tested geomechanical-model and a clear business need for knowledge on the impact of GPM-induced pore pressure changes on seismicity, a field injection test should be considered in case GPM will be implemented in the coming years. Such a test can gain valuable information on the effect of injection on seismicity and the mechanisms acting at the slipping fault. But it must be executed within an acceptable safety envelope, include detailed statistical techniques to prove the effect of injection on seismicity, and involve extensive in-situ data collection and monitoring. Through a parallel approach of modelling and high-quality in-situ data collection, progress could be made in gaining a mechanism-based understanding of injection-induced fault slip, so that the findings of the injection test can be applied to GPM across the Groningen field.

3. Groningen Field Description and Performance

3.1. Groningen Reservoir Architecture and Volumes

The Groningen structure is a NNW-SSE-trending, gently folded, wedge-shaped intrabasinal high with an extent of 40 km by 25 km with strongly faulted east, south, and west flanks and a gently dipping north flank (Figure A1.1). The main reservoir is the Lower Permian, Rotliegend Slochteren mainly aeolean sandstone, which has good properties with porosities in the range of 15-20% and permeabilities of up to 3 D. The reservoir thickness varies from some 70 m in the SE part of the field to 240 m in the NW (Figure A1.2). The Slochteren formation can be subdivided into the Upper and Lower Slochteren, which are overall in communication. The Slochteren is overlain by the poorer quality Ten Boer claystone, which depletes into the Slochteren. The Rotliegend is covered by the Late Permian Zechstein evaporite sequence, consisting of carbonate, anhydrite, and halite, which acts as the top reservoir seal. The reservoir unconformably overlies the Carboniferous fluvio-deltaic Limburg Group (Westphalian), which consists of poor-quality sandstone, shales and coals.

There are about 1700 mapped faults intersecting the reservoir with predominantly E-W and NNW-SSE orientations and throws of less than 100 m, which is less than the average reservoir thickness of about 200 m. None of the faults within the main part of the reservoir appear to act as significant barriers to gas flow, although they might hold a small pressure differential.

The gas-water contact is located at about 3,000 m depth, with some depth variations observed for various compartments. A very weak aquifer underlies the northern part of the field.

Typically, Groningen gas is composed of around 80% CH_4, 14% N_2 and 1% CO_2, with C_2-C_5 components making up the remainder. The field contained approximately 2,900 bcm of gas[4], of which, on 01/01/15, about 2,050 bcm have been produced.

The main petroleum engineering uncertainties, beside the volume of gas initially in place, are:

- Late life behaviour of field due to potential pressure support from adjacent formations (i.e. "slow gas initially in place")
  - The Ten Boer connectivity and depletion behaviour is not fully understood.
  - The connectivity and depletion behaviour of the underlying Carboniferous reservoir is also uncertain.
- Depletion behaviour of periphery of the field
  - The history match of the peripheral area is not as high quality as the field average.
  - Subsidence in north-western part of field is overestimated (when compared to measurements).
  - Connectivity between fault blocks.
- Mechanism for aquifer water ingression: Bottom water vs. breakthrough in high-permeability streaks.

4 All volumes are given in norm cubic meters, if not stated otherwise.

3.2. Development History and Performance

The field was discovered in 1959 and first production was in 1963. The development started in the south of the field before the actual northern extent of the field was known. This led to a lag in pressure decline in the north until further production wells were put on production in the north in the 1970s.

In the initial years, the Groningen field, due to its size and reservoir pressure, was capable of supplying the necessary volumes to the market and had the necessary capacity to supply the required swing volumes as the customers requested their gas (Figure 3.1). Until the mid-1970s a peak rate of almost 90 bcm/a was achieved. Since the late 1970s, production from smaller fields was given priority and Groningen became a swing producer for times in which the small fields could not meet demand. The initial reservoir pressure of about 350 bar declined to about 180 bar by 1990, necessitating the introduction of compression on all production clusters (Figure 3.2). With decreasing production capacity from Groningen, the Norg and Grijpskerk fields were added in 1997 as underground gas storage (UGS) to the Groningen system to supply gas for peak demand. The reservoir pressure has meanwhile declined to less than 100 bar.

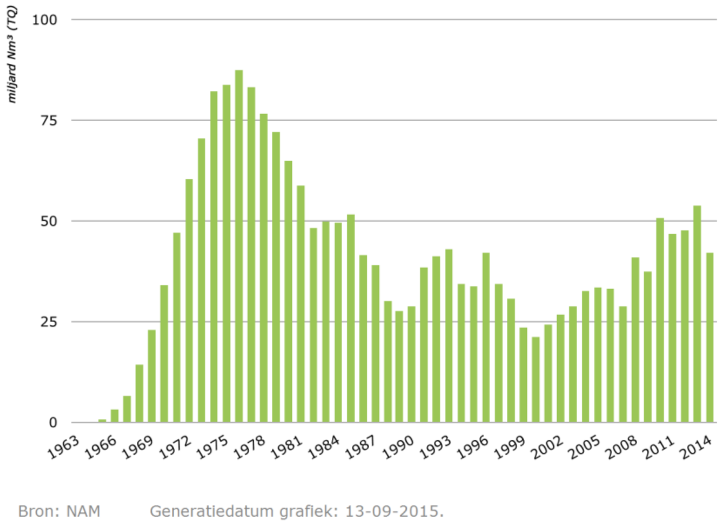


Figure 3.1: Historical gas production from the Groningen field in bcm per year.

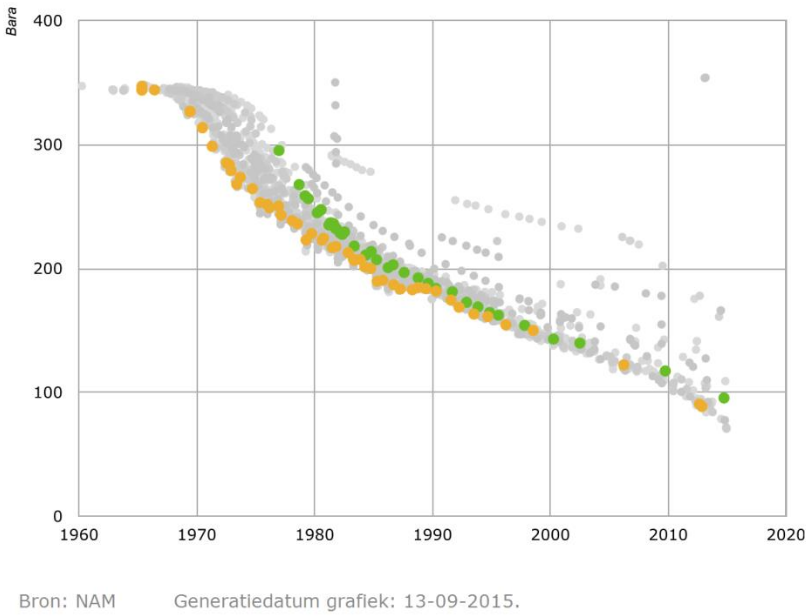


Figure 3.2: Historical reservoir pressures measured at different production clusters. The orange points represent pressures at the southern-most Tuschenklappen cluster and the green points pressures at the northern-most t-Zandt cluster. Due to the later development of the north of the field, the pressures in that area remained higher than the pressures in the south until the late 1980s.

3.3. Existing Infrastructure

The Groningen System includes the Groningen field with 20 production clusters (Figure A1.3), two satellite clusters, and the two UGS sites at Norg and Grijpskerk. Its support facilities include pipeline systems and gas condensate separation and export facilities. There are 258 available production, 22 observation, and three water disposal wells. Additionally, 24 abandoned wells exist in the field.

The 20 production clusters have more or less identical process equipment (Figure 3.3). The only major difference between the clusters is the number of wells feeding into the process equipment. The process equipment consists of liquid knock-out vessels, air coolers, a single-stage depletion compressor, gas/gas heat exchanger, Joule-Thompson valve, and low-temperature separators. Auxiliary processing equipment to recover water and condensate and a glycol circuit are also incorporated in the facility. Each cluster has a single compressor train and dual gas processing trains. The processing facilities primarily serve separate water and condensate from the gas. Since the reservoir pressure is declining due to production, a depletion compressor ensures that the facility remains operating in its operating window and delivering sufficient gas at sales pressure. The current plants have a large overcapacity and the compressors are the system bottlenecks.

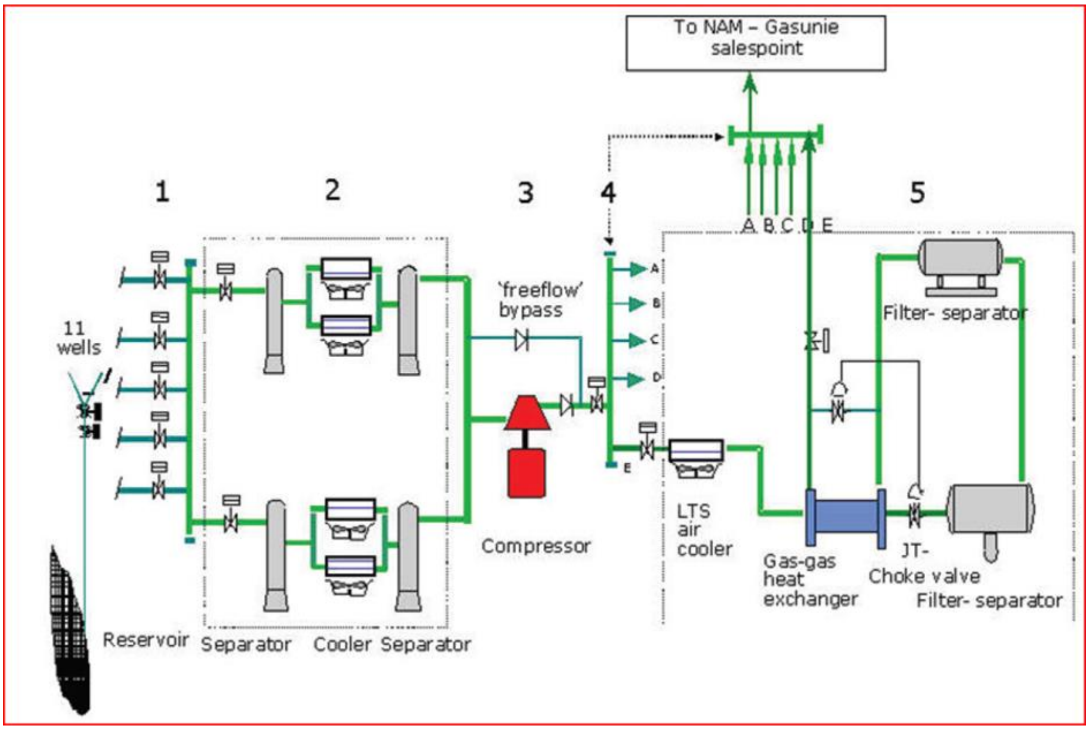


Figure 3.3: Schematic of processing facilities at each of the 20 production clusters.

The condensate and water separated from the gas are transported by pipeline to Delfzijl, where the water is separated and injected into the water leg of the Groningen field at Borgsweer. The gas is delivered from the clusters into the main ring line, which has seven custody transfer stations to deliver the gas into the Dutch grid. The pipeline system is designed in the shape of a large 'figure 8' to increase operational flexibility and reliability. The total system consists of about 162 km of pipe with diameters of 24 to 36 inches. At the custody transfer stations, the gas is contractually obliged to have a pressure between 55 and 65.5 barg and a temperature between 10 and 30 °C.

4. Pressure Management and Recovery under Injection

4.1. Subsurface Concepts

The key decisions for GPM related to the subsurface are

1. the pressure management policy, which consists of
   a. the final equilibrium reservoir pressure at field abandonment
   b. tolerances to pressure increases and decreases over time during GPM
      i. at the regional level
      ii. at the local level, around injection and production wells, and
2. the injection locations.

The regional pressure at the start of GPM depends on the GPM implementation date and on the production scenario to that date. Under production policy with 33 bcm/a, the pressure at the notional start date of GPM (2024) is expected to be approximately 65 bar in the north and approximately 40 bar in the south.

The regions are all interconnected, which means that gas cross-flows between regions. Regions at a higher pressure will have a net outflow, while regions at low pressure will have a net inflow. GPM can be designed to maintain the pressure in a region by injecting a volume that replaces the net outflow from production and crossflow. GPM can also be designed to increase or decrease the pressure in a region by surplus injection or production respectively.

The imbalance in regional pressure can only be sustained by continued injection and production. Ultimately, as a result of the cross-flow between regions, all pressures have to equilibrate to the same field pressure. The choice of the final equilibrium pressure is a key decision for the pressure management policy. The full range is described by four options and the final equilibrium pressure can be:

1) above the highest regional pressure at the start GPM (~65 bar in the north by 2024),
2) at the average field pressure at the start of GPM (~55 bar by 2024),
3) at the lowest regional pressure at the start of GPM (~40 bar in the south by 2024), or
4) at the abandonment pressure for third-stage compression (~10 bar).

A graphical representation of a pressure management policy is shown in Figure 4.1. The four options for the final equilibrium pressure are indicated by dashed lines. The choice of the final equilibrium pressure will depend on the geomechanical realisation. If a pressure increase is considered more hazardous than continued depletion, the pressure should equilibrate towards the low end (“minimum repressurisation” approach, ref. Figure 1.6). If a pressure increase is considered effective in reducing seismic hazard, further depletion should be avoided and pressure should equilibrate towards the high end (“equilibrate” approach, ref. Figure 1.6).

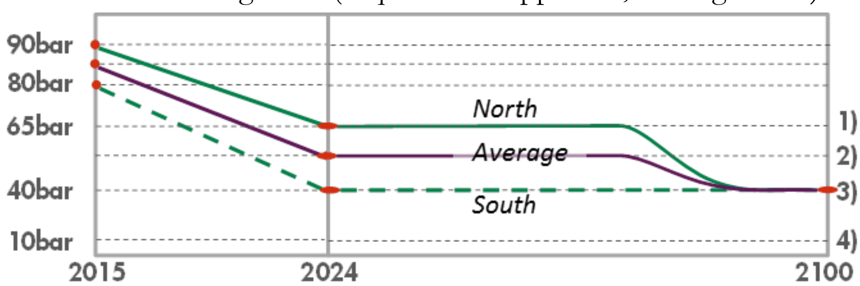


Figure 4.1: Example of a schematic representation of a pressure management policy showing the pressure in the north (solid green) and south (dashed green), as well as the field average pressure (solid purple).

Figure 4.2 shows a range of regional pressure management policies. This matrix of conceptual policies is intended to help developing GPM concepts. The feasibility and attractiveness of the individual policies will depend on future insights on the seismicity risk for depletion and injection and an assessment across all other value drivers. This might render some policies unfeasible or suboptimal.

Rows 1 to 4 show policies with decreasing abandonment pressure. Rows 1 and 2 require confidence in the effectiveness of GPM. The columns depict different classes of pressure management policies:

A. Immediate convergence. Only the top one (A1) would require injection, the others (A2-A4) are cases with depletion production only and no injection.
B. Regional pressures are maintained constant from the start of GPM until they are allowed to equilibrate at the end of field life.
C. Only the northern pressure is maintained constant from the start of GPM, whereas the southern pressure is allowed to decline first before it is maintained constant until at the end of field life, and the pressures are allowed to equilibrate. The further depletion in the south allows higher production rates.
D. Analogous to C, only the southern pressure is maintained constant from the start of GPM, whereas the pressure in the north is first increased before being stabilised to create a larger pressure difference between north and south and thereby allowing higher production rates.
E. Combining C and D, both, the pressure in the south and the pressure in the north are first allowed to move in opposite directions before being kept stable und then allowed to equilibrate. Again, the larger N-S pressure aims at increasing higher production rates under GPM.

Columns C to E show increasing tolerance to regional pressure change to assess the impact on the production rate. Columns D and E are mainly relevant in the context of a north-south (N-S) sweep injection scheme.

The above policies focus mainly on pressure stabilisation or even increase in at least part of the field. Policies with a reduced pressure decline across the field can also be achieved with GPM and could to be assessed later as well (Figure 1.4).

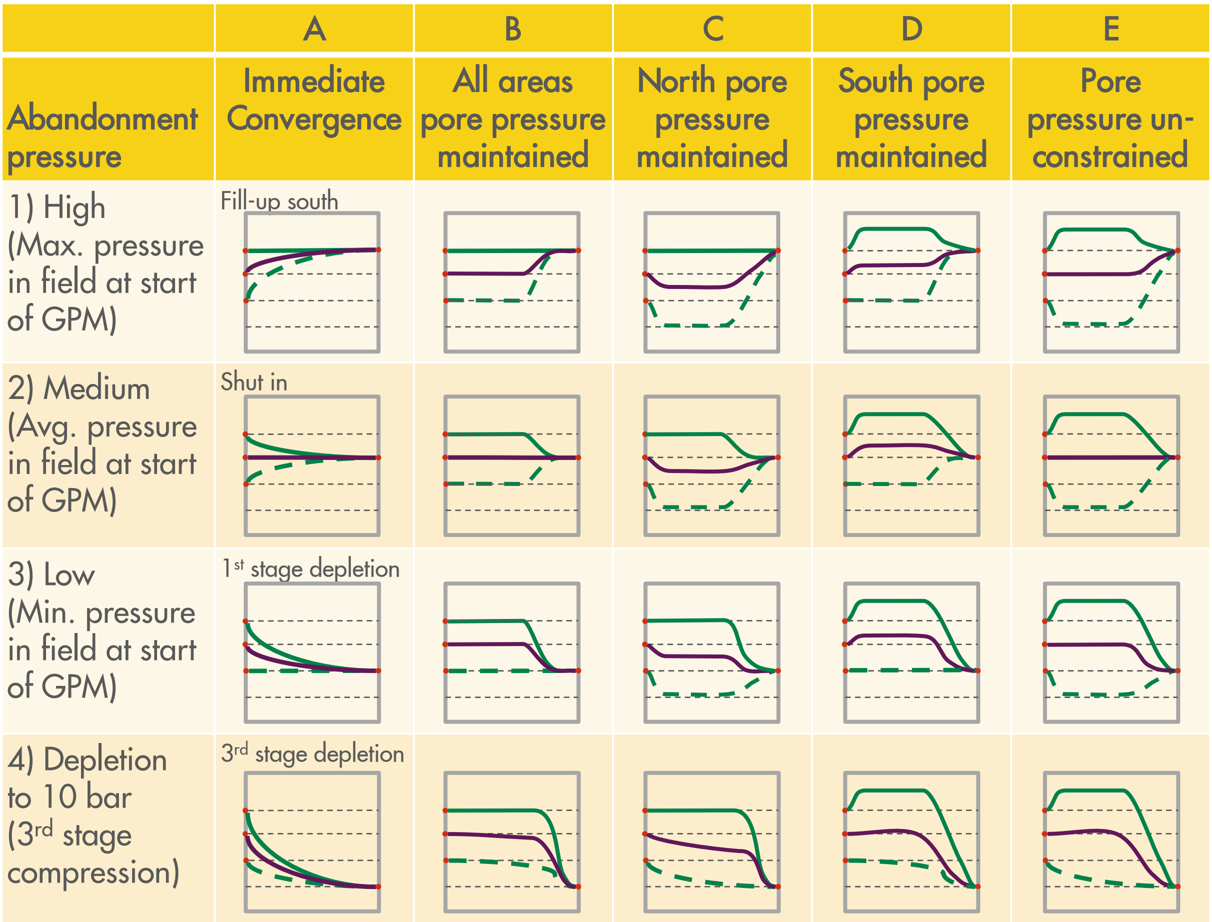


Figure 4.2: **Overview of the range of potential pressure management policies. Each chart shows conceptually the average pressures over time from the start of GPM to the end of field life. Three pressure profiles are drawn: The average pressure in the north (solid green line), the south (dashed green line), and in the entire field (purple line). The pressure management policies are arranged from top to bottom according to decreasing abandonment pressure and from left to right by the increasing tolerance to pressure changes.**

The above pressure management policies apply to the average regional pressures in the reservoir. Injection will however also introduce a local pressure deviation in the near-wellbore area to enable flow from the injection well into the reservoir. This pressure difference is called fall-off and it is the analogue of the drawdown pressure to enable flow from the reservoir towards a production well.

An additional pressure management policy is required for the fall-off at the injection wells. The fall-off pressure is related to the injection rate and the wellbore radius. The area affected by the pressure increase will remain localised due to simultaneous production. Seasonal production variations in the south already give rise to pressure fluctuations of about 5 bar. Higher fall-off pressures would enable a more efficient utilisation of injection wells.

The pressure management policies visualised in Figure 4.2 can be achieved with different injector-producer patterns. The range of injection locations is captured by four archetypes, dispersed, semi-dispersed, central and N-S sweep, as illustrated in Figure 4.3. The dispersed and semi-dispersed concepts are examples of a pattern injection. The dispersed concept has 20-30 wells located between production clusters. The semi-dispersed concept has the same pattern, though without the 10-15 most southern wells to avoid excessive breakthrough of N_2 in the south. The central concept is an example of a local injection scheme, e.g. to temporarily defer a pressure decrease in the Loppersum area. The N-S injection pattern is an example of a line drive scheme. Further optimisation of the selected injection pattern could be done at a later stage, for example to minimise the need of additional wells and maximise the reservoir sweep.

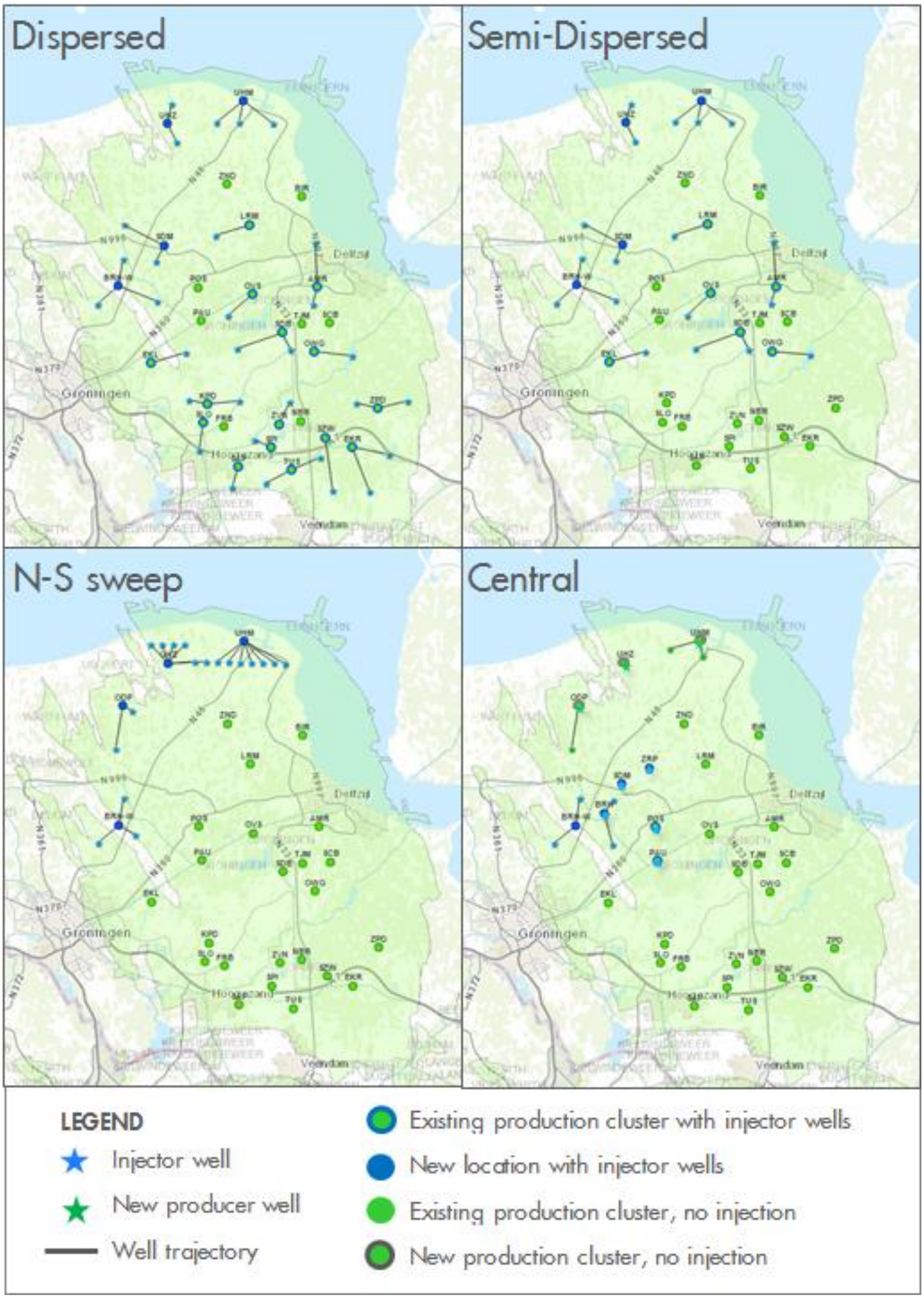


Figure 4.3: **Four archetype injection patterns to implement the GPM pressure management policies. Schematic pictures only, with notional locations and number of injectors. For a small, local injection scheme (bottom, right), additional flank producer wells would have to be drilled, while in all other concepts the existing producer wells would suffice.**

4.2. Modelling Objectives and Approach

4.2.1. Modelling Objectives

The premise of the subsurface work is that the (lifecycle) seismic hazard of a GPM concept depends predominantly on the pressure management policy. Thermal effects have been identified as a possible cause for seismicity [3], but have not been considered here. These effects would have to be managed by controlling the temperature of the injection gas.

The objective of the subsurface modelling work is to identify which pressure management policies are practical and which injection patterns are best suited to implement them, and to estimate the production and injection rates and gas recoveries for the different concepts.

4.2.2. Modelling Approach

For a range of concepts, forecasts are made for the injection rate of N_2 and the production rate of Groningen gas and N_2. The total demand for and back-produced amount of N_2 determines the phasing of the ASUs. In the reservoir, the N_2 fluid is modelled with the same compressibility and viscosity as the Groningen gas. The same approach is taken for CO_2 co-injection. This is deemed an appropriate simplification for the current modelling objectives.

The vantage point for the modelling work is the existing history-matched asset model. Modifications were made to incorporate

- injection wells and N_2 availability,
- pressure management, and
- N_2 migration in the reservoir.

The subsurface uncertainty range relevant to depletion forecasts has been expanded to include heterogeneity in reservoir permeability. Heterogeneity will enhance mixing (dispersion) of the N_2. As a result, the ultimate recovery will improve. In addition, the N_2 front will become more dispersed, resulting in an earlier breakthrough, a slower increase in N_2 concentration (leading to longer time before reaching N_2 cut-off) and therefore more N_2 production.

Furthermore, the uncertainty range of fault transmissibility has been reviewed in the context of N_2 displacing gas. Sealing faults would divert the N_2 sweep and leave pockets of hydrocarbon gas stranded in their shadow. The historic production data, however, provides limited room for such a downside.

A notional 80% N_2 cut-off based on energy considerations is applied to the wells. Once the N_2 concentration in a well reaches that value, the well is shut-in. Otherwise, no economic cut-off is applied to the forecasts.

4.3. Subsurface Concept Examples

4.3.1. Concept Example 1 – Confident in benign effect of pore pressure increase

If it is assumed that pressure increase will have a benign effect on seismicity, a pressure management policy can be adopted that minimises further compaction from depletion in the seismically critical area around Loppersum. With this pressure management policy, all pressures in the field are ultimately increased to match the highest regional pressure at the start of GPM, which is ~65 bar in the north of the field. The pressure management policy (C1) is implemented with a semi-dispersed injection pattern.

For the period prior to GPM implementation, a yearly offtake of 33 bcm is assumed in this example. Injection starts in 2024 and peaks at ~20 bcm/a after completion of the sixth ASU. First breakthrough occurs a few years after the start of injection. Figure 4.4 and Figure 4.5 provide an overview of the pressure change over time and the corresponding injection and production rates that could be achieved for this concept.

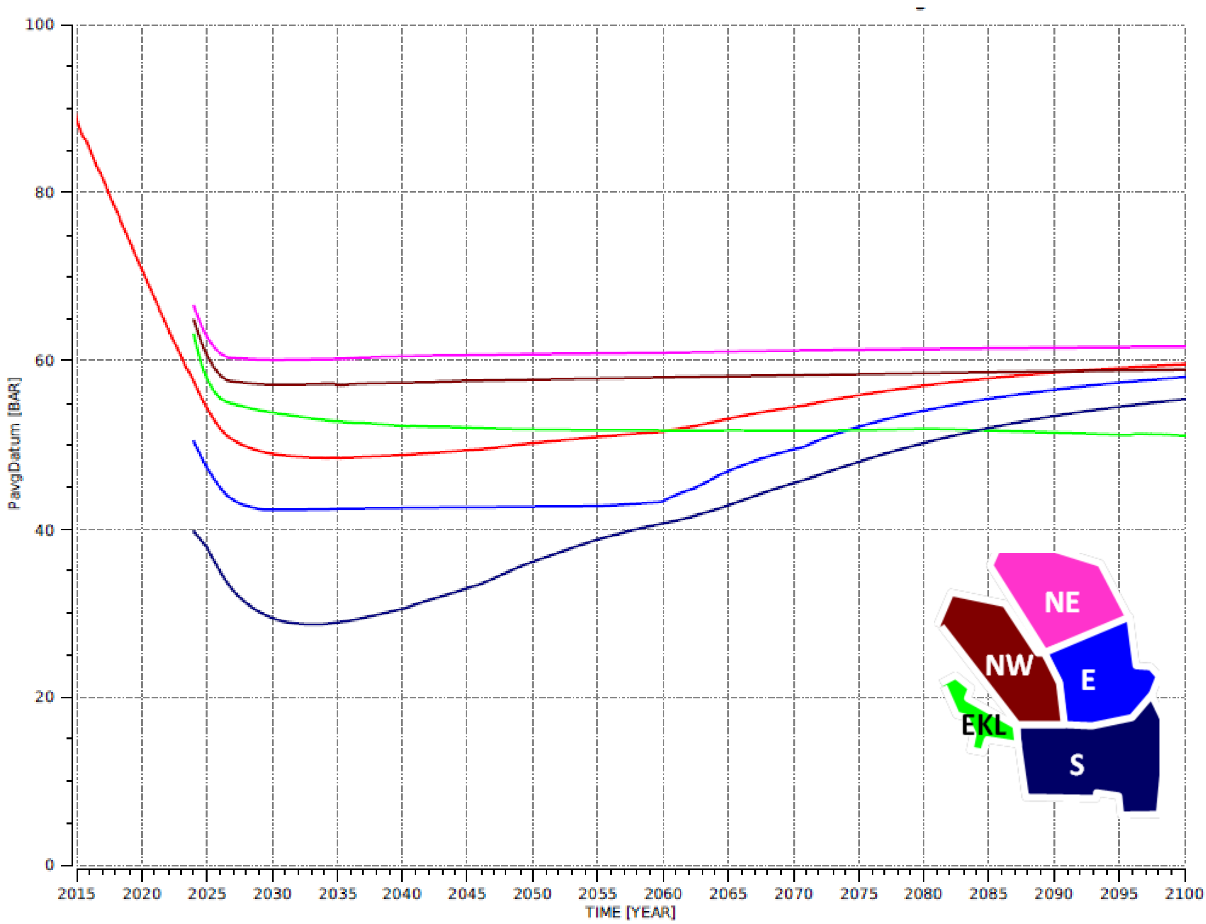


Figure 4.4: Pressure forecasts for GPM concept example 1: The bold red line represents the field average pressure. The 5 remaining lines show the average pressure for different areas in the field.

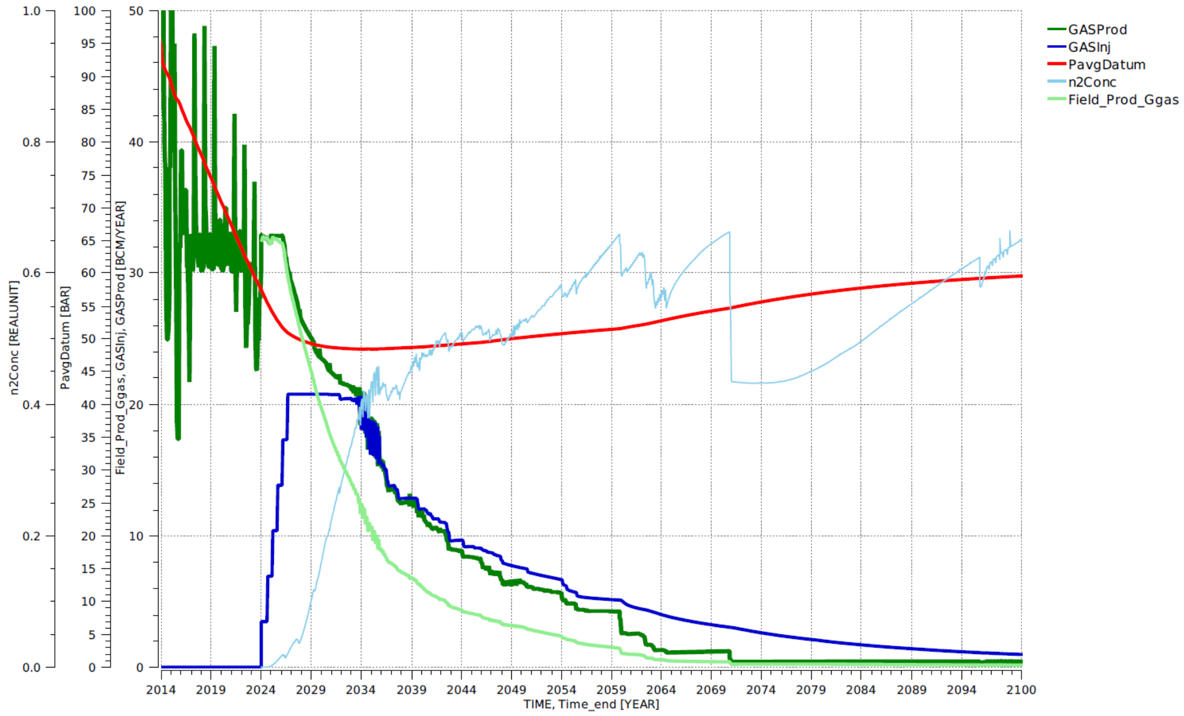


Figure 4.5: **Production and injection forecasts for GPM concept example 1: Total produced gas rate (solid green), Groningen gas production rate (light green), N_2 concentration (light blue), N_2 injection rate (dark blue), and average field pressure (red).**

Figure 4.6: Expected pressure in bar at the start of GPM (left), expected minimum pressure (middle) and maximum pressure increase (right) over the lifetime of GPM example concept 1. Figure 4.6 shows, on the left, the pressure at the start of GPM. The minimal pressure reached over the lifetime of the GPM concept in this example is shown in the middle. This allows an estimate of the compaction-induced seismicity that is still expected from this GPM concept example and the further compaction-induced seismicity that could be avoided. The maximum pore pressure increase over the lifetime of the field is shown on the right. The seismicity induced by pore pressure increase is uncertain.

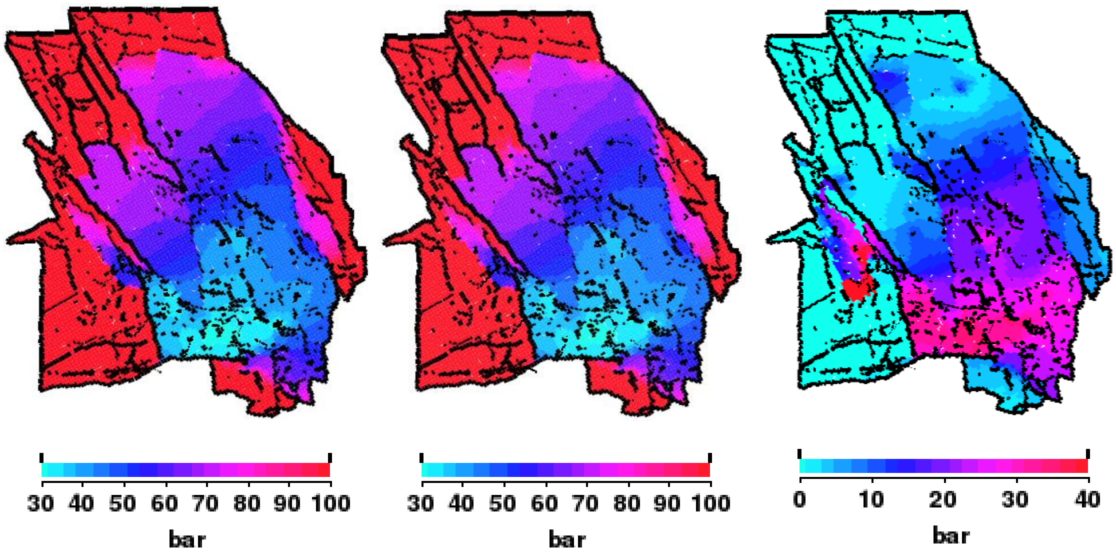


Figure 4.6: Expected pressure in bar at the start of GPM (left), expected minimum pressure (middle) and maximum pressure increase (right) over the lifetime of GPM example concept 1. (Note that the shown repressurisation in the Eemskanaal area, at the western flank of the modelled area is due to a strong aquifer, which is perceived to be a model artefact.)

4.3.2. Concept Example 2 – Minimum Repressurisation Approach

In this example, GPM is implemented cautiously to avoid a pressure increase that could induce additional seismicity. With this pressure management policy, all pressures in the field are decreased to match the lowest regional pressure at the start of GPM, which is 40 bar in the south. The pressure management policy (B3) is implemented with a semi-dispersed injection pattern.

For the period prior to GPM implementation, a yearly offtake of 33 bcm/a is assumed in this example. Injection starts in 2024 and peaks at ~10 bcm/a after completion of the third ASU. First breakthrough occurs a few years after the start of injection. Figure 4.7 and Figure 4.8 provide an overview of the pressure change over time and the corresponding injection and production rates that could be achieved for this concept.

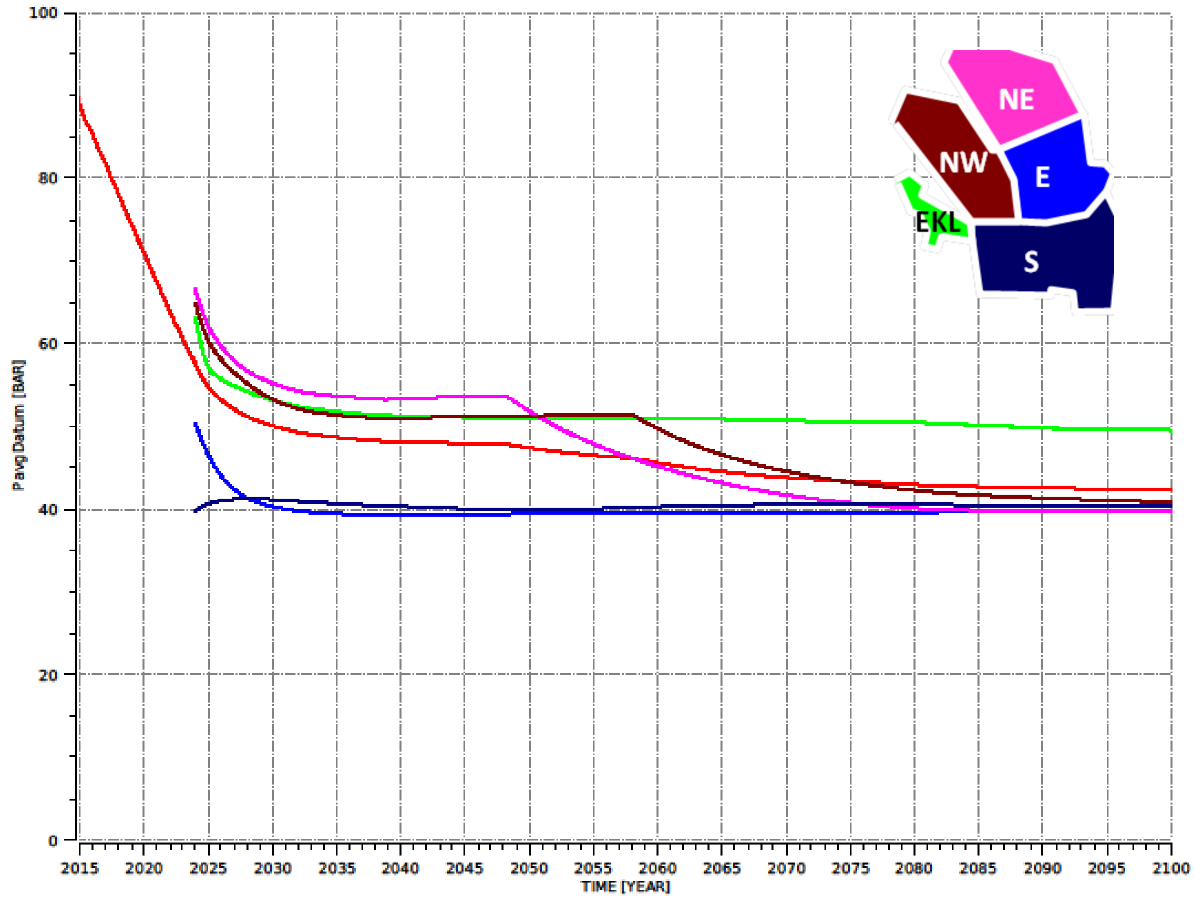


Figure 4.7: **Pressure forecasts for GPM concept example 1: The bold red line represents the field average pressure. The five remaining lines show the average pressure for different areas in the field.**

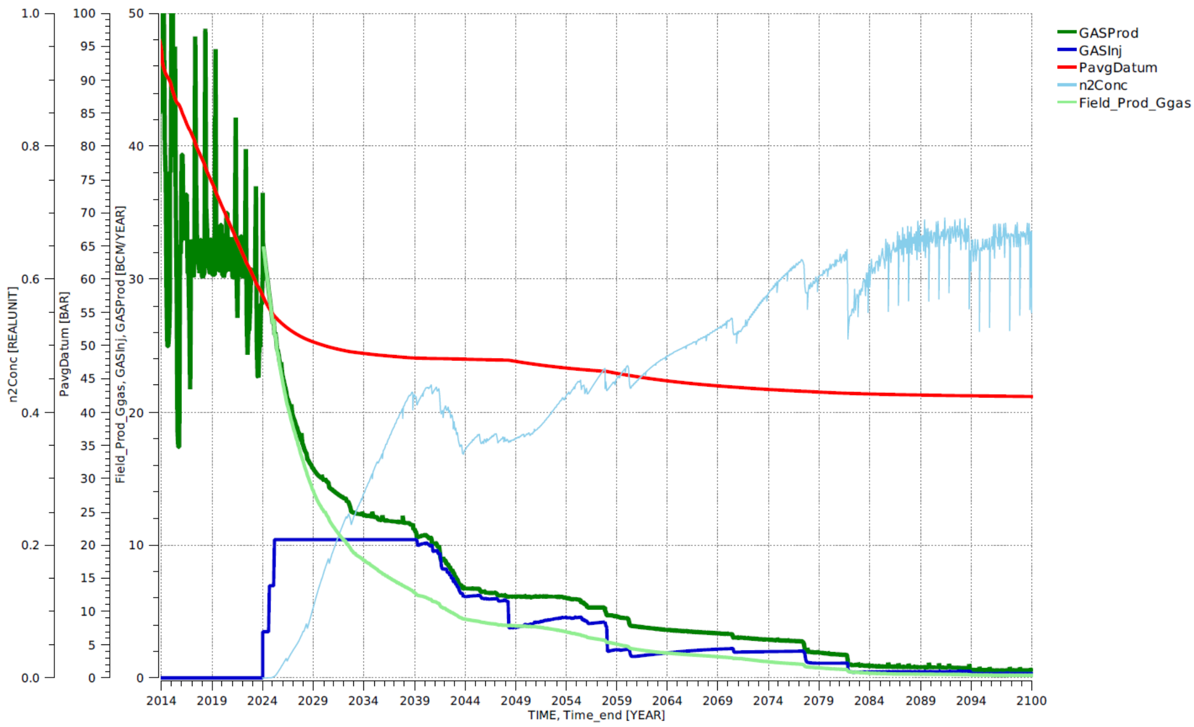
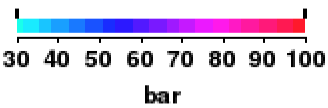


Figure 4.8: **Production and injection forecasts for GPM concept example 1: Total produced gas rate (solid green), Groningen gas production rate (light green), N_2 concentration (light blue), N_2 injection rate (dark blue), and average field pressure (red).**



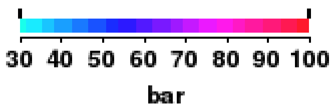
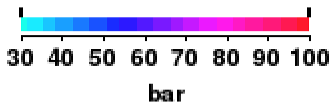
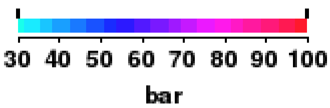
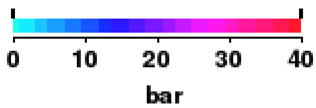


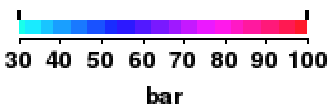
Figure 4.9 shows, on the left, the pressure at the start of GPM. The minimal pressure reached over the lifetime of the GPM concept in this example is shown in the middle. This allows an estimate of the compaction-induced seismicity that is still expected from this GPM concept example and the further compaction-induced seismicity that could be avoided. The maximum pressure increase over the lifetime of the field is shown on the right. The seismicity induced by pore



pressure increase is uncertain. Compared to







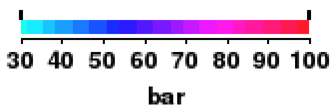


Figure 4.6,

Figure 4.9 shows how this second pressure management policy limits the extent of repressurisation and the associated potential seismicity risk while incurring a larger compaction with associated compaction-induced seismicity.

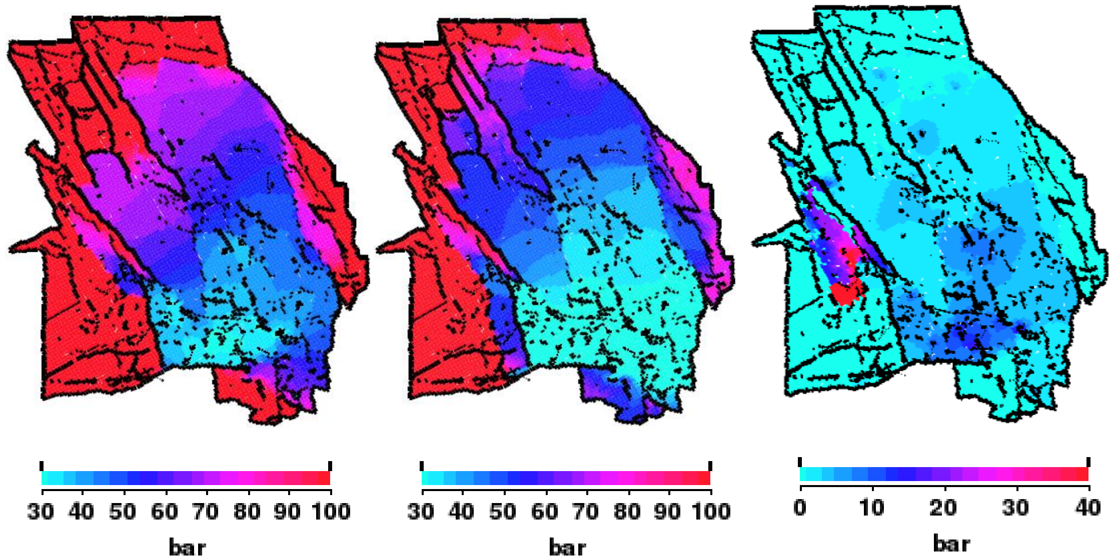


Figure 4.9: Expected pressure in bar at the start of GPM (left), expected minimum pressure (middle) and maximum pressure increase (right) over the lifetime of GPM example concept 1. (Note that the shown repressurisation in the Eemskanaal area, at the western flank of the modelled area is due to a strong aquifer, which is perceived to be a model artefact.)

4.3.3. Ultimate Recovery for Different GPM Concepts

Ultimate recovery depends on two parameters, the final equilibrium pressure and the sweep efficiency. This relation is shown in Figure 4.10, which is similar to a typical gas field P/Z material balance plot. The green markers represent continued production-only behaviour. Injected N_2 will displace part of the hydrocarbon gas. The displaced hydrocarbon gas can be produced without the corresponding drop in average pressure. Incremental production can continue until the N_2 concentration reaches the economic limit. The amount recovered by N_2 displacement is called the sweep efficiency. All subsurface concepts show a sweep efficiency in the range of 50% to 70%. Any implementation of a GPM concept to avoid depletion below ~40 bar will, despite the N_2 sweep, result in a production loss compared to continued depletion to ~10 bar, ranging up to ~100 bcm.

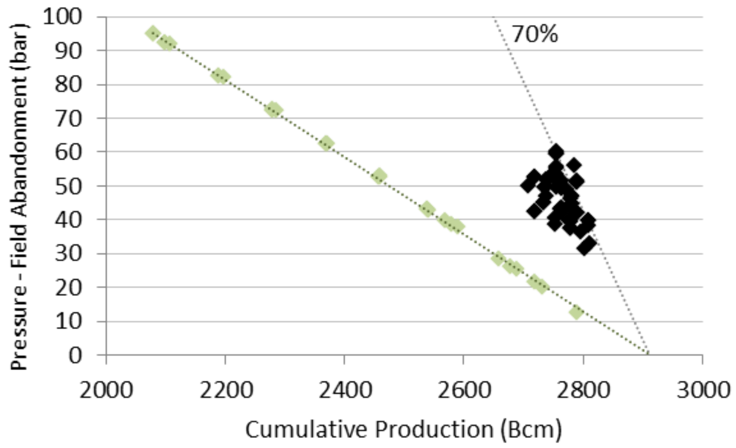


Figure 4.10: **Cumulative production as a function of average field pressure for depletion (green) and for GPM (black).**

Figure 4.11 and Figure 4.12 show the migration of the injected N_2 through the reservoir at different points in time. The first is an example of a good sweep which displaces 70% of the Groningen gas otherwise left behind. The second is an example of a sweep that would require further optimization in well locations as the N_2 sweep only displaces 50% of the Groningen gas.

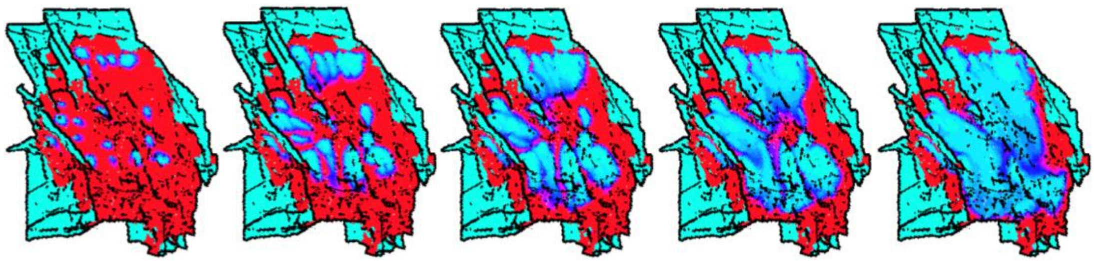


Figure 4.11: **Snapshots in time showing the anticipated position of the nitrogen front in the reservoir in 2027, 2032, 2040, 2050, and 2100 for GPM example concept 1. The Groningen gas (concentration) is shown in red. This is an example of a good sweep.**

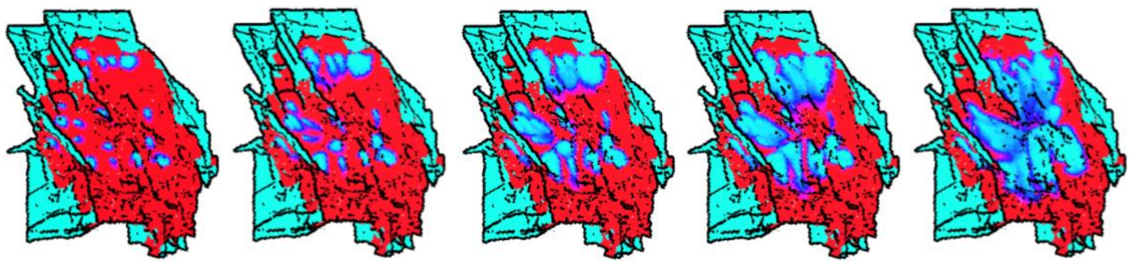


Figure 4.12: **Snapshots in time showing the anticipated position of the nitrogen front in the reservoir in 2027, 2032, 2040, 2050, and 2100 for GPM example concept 2. The Groningen gas (concentration) is shown in red. This is an example of a sweep that requires further optimisation of the well locations.**

4.3.4. Rate for Different GPM Subsurface Concepts

In a pattern injection like dispersed and semi-dispersed, the rate depends on the local pressure difference between injector-producer pairs. The regional pressure is not expected to have a significant impact on the rate.

In the N-S sweep, the bottleneck for the rate is the flux of gas from north to south. This flux depends on the pressure gradient from north to south. Surplus offtake beyond the prevailing flux will result in a further pressure drop in the south. Similarly, surplus injection will result in a pressure increase in the north. Therefore, constraints on the pressure increase in the north or decrease in the south will directly limit the maximum production and injection rates.

These mechanisms are represented schematically in Figure 4.13. The relation between N-S pressure difference and total field injection rate is shown in Figure 4.14.

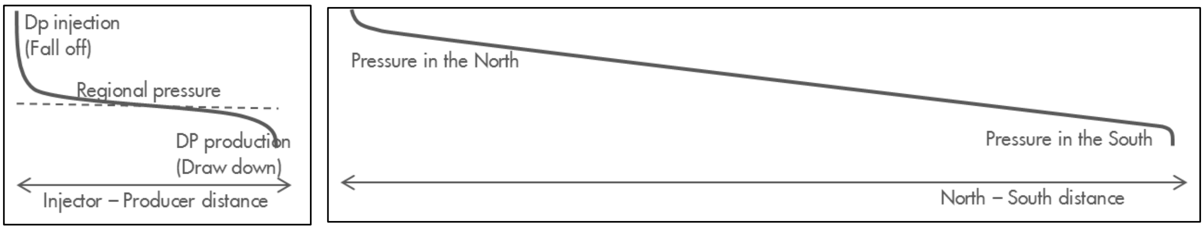


Figure 4.13: Stationary pressure profile between an injector-producer pair under voidage replacement for a pattern injection scheme (left) like dispersed or semi-dispersed and a line drive (right) like N-S sweep.

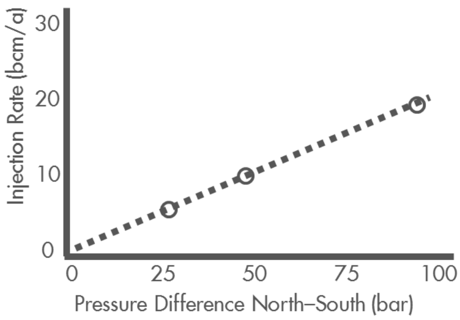


Figure 4.14: Total field production rate in a N-S sweep injection pattern predominantly depends on the regional pressure difference between the north and south.

4.3.5. Breakthrough Time and Cycling

Breakthrough time depends on the injector-producer distance and the rate. Pattern injection schemes like dispersed and semi-dispersed have relatively short injector-producer distances of a few kilometres. This results in early breakthrough of the gas in all the clusters after a few years of production and large volumes of back-produced N_2. In the N-S sweep the N_2 front passes clusters when it moves south. These clusters can be shut in early without impact on the sweep efficiency. As a consequence, the volume of back-produced N_2 is much smaller than for a pattern injection.

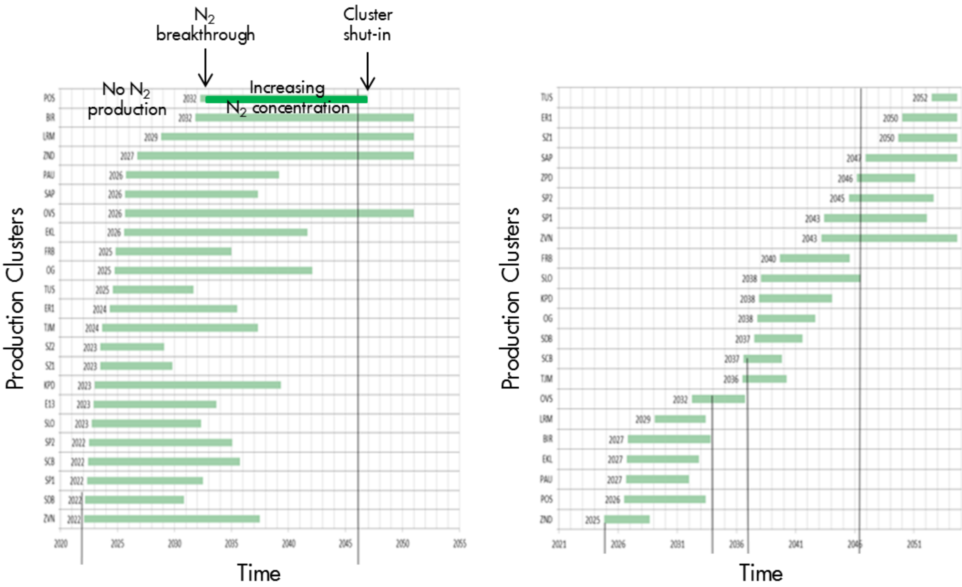


Figure 4.15: **Indicative nitrogen (N_2) breakthrough behaviour for two injection patterns, the dispersed pattern (left) and the N-S sweep pattern (right). The horizontal bars represent for each cluster the timing when N_2 breaks through and the time, when the cluster is shut-in as a result of high N_2 concentration. Given the larger injector-producer distance in the N-S sweep pattern, the N_2 breakthroughs are later than in the dispersed pattern. (Note that the clusters are ordered in each chart by their breakthrough timing).**

5. Appraisal and Testing of Injection

5.1. Introduction

As laid-out in section 2.7, an injection field test might be required to demonstrate the impact (or lack thereof) of (local) injection-induced pore pressure increase on seismicity. Analogues, theoretical rock mechanics, and laboratory tests alone will not provide a conclusive answer to the question if injection will lead to less, more or similar seismicity compared to the current few-bar-per-year depletion of the Groningen field. One or more field tests might be the only option to address this question; however, test outcomes may be inconclusive or contradictory to decide on GPM.

Rather than injecting N_2 gas or any other new injectant in such a field test, there is an option to use existing production wells and compressors to re-inject Groningen gas. This would be a relatively fast and efficient way to locally increase the reservoir pressure. The existing geophone network, possibly augmented with additional geophones, would be used to observe any change in seismicity.

The key success factors for a test are as follows:

1. Appropriate risk mitigation can be put in place for potential exposure to injection-induced seismic hazard. This might require temporarily relocating people from the test area.
2. The test has clear relevance to GPM, which means the conditions at the tested area(s) must be representative or similar to all locations in GPM with a pore pressure increase.
3. The acquired test data needs to be interpretable.
4. Preparing and conducting the test(s) needs to be short enough to provide timely information for a decision on GPM.
5. During a test, the field can continue production to maintain security of supply.

Like GPM, a test would only be implemented if continued production under depletion – with structural upgrading – was deemed unacceptable and only GPM remained. Given the risks associated with a test, a test would only be implemented when continued depletion was deemed unacceptable.

5.2. Test Objectives and Measurement Options

The key objective of an injection test is to prove whether injection-induced pore pressure increase will increase, decrease, or not influence seismicity. Depending on the pressure management policy (section 4.1), different tests at different locations are required. The three incremental test objectives are visualised in Table 5.1.

Table 5.1: Injection test objectives

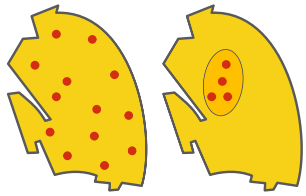
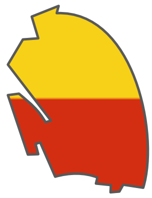
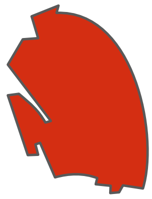
A	To prove for every injector where injection is planned that a near-wellbore pressure increase, representative to GPM injection, has acceptable seismicity risks. This is shown here for a case with injection across the field, and in a small area.	
B	To prove for an entire region of the field that a pore pressure increase from regional pressure equilibration is within acceptable seismic safety limits. This is shown here for the southern half of the field.	
C	To prove that a pore pressure increase anywhere in the field would have a benign effect on seismicity.	

Figure 5.2 shows which test objectives would be required for each of the 20 regional pressure management policies. The first symbol denotes the test objective required prior to implementation of the corresponding GPM policy. The second symbol denotes the test objective that can be postponed to a later date. Such a phased testing could be considered if the early implementation decisions for GPM would not change significantly if we would have known the outcome of the later tests upfront.

As an example, Figure 5.1 shows the regional pressure management policy B1 (Figure 5.2) with pressure equilibrating to the maximum field pressure at the end of GPM. The imminent test objective is to confirm whether a local pressure increase around the injectors is within acceptable safety limits (objective A). The test should be representative to the GPM operating conditions and might be required at every injection location. For pressure management policy B1, only later in field life, further testing must demonstrate that pore pressure increase has acceptable safety risks or is even beneficial everywhere (objective C). More importantly, it must be understood that if the second test cannot demonstrate that field-wide pressure increase is beneficial or at least safe, moving away from case B1 to e.g. B2 or B3 is still a safe alternative.

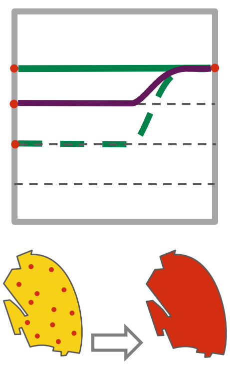


Figure 5.1: Example of a regional pressure policy with imminent (pre-GPM) and later test requirements.

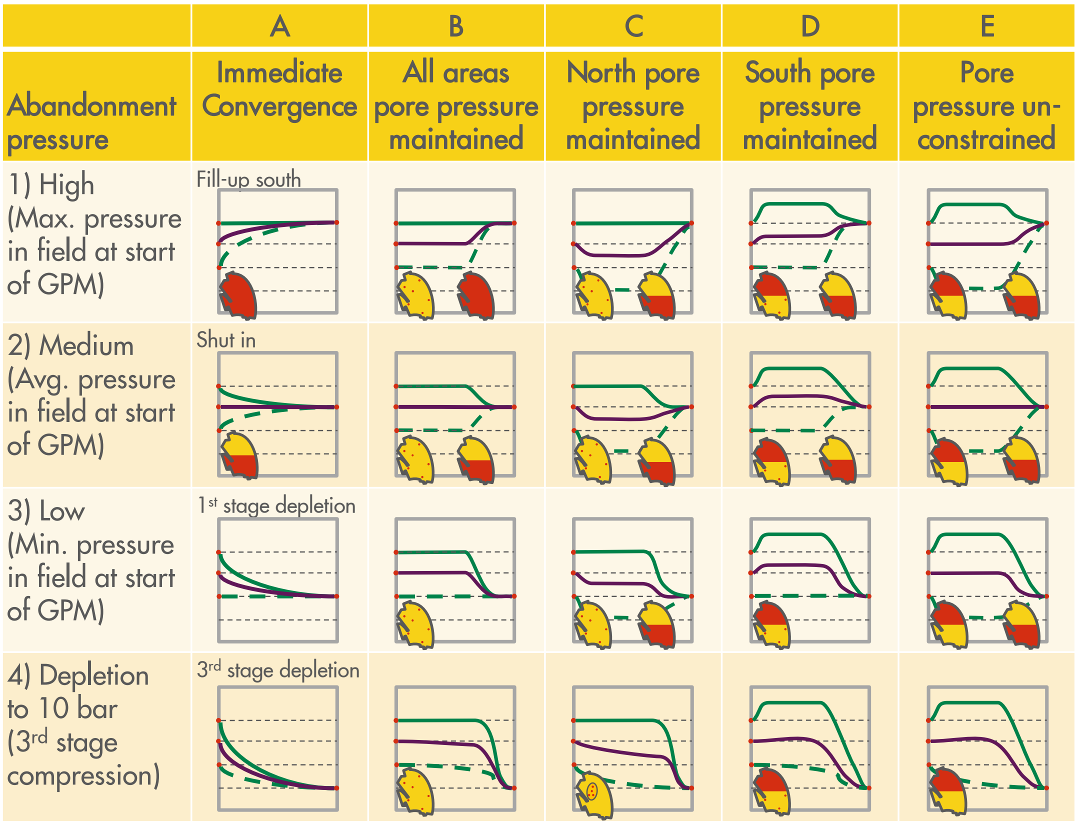


Figure 5.2: **Overview of the range of potential pressure management policies, with indications of required testing for different phases. The three lines in each pressure plot indicate regional pressure over time in the north (solid green), south (dashed green), and on average (purple).**

There are four types of data that should be measured (Table 5.2). As a minimum requirement, the seismicity before and after the test and the pore pressure change needs to be recorded in order to control and calibrate the test. Additionally, the expected associated increase in total horizontal stress should be measured, such that the horizontal stress path coefficient during injection could be estimated (see section 2.4), as well as the vertical extension of the reservoir.

Table 5.2: **Range of measurements as part of an injection test.**

Data	**Method**
1. Direct measurements of seismicity	Existing and possibly additional shallow and deep geophones/fibre optics and accelerometers at surface; note that new deep geophones/fibre optics could be installed in existing production wells (requiring workovers and using gelled kill fluids, causing well impairment when reinstating the well for production) or preferably in dedicated, newly drilled, non-perforated (i.e. observation) wells
2. Pore pressure change	Tubing-head pressure measurements in the injector and adjacent producers/observation wells and possibly complemented through downhole memory or cable-less real-time gauges in adjacent producers/observation wells

Data	Method
3. Increase in total horizontal stress per unit increase in pore pressure (stress path coefficient γ_{hi})	Extended leak-off tests in a dedicated, new well, alternatively a recompletion of existing wells or minifrac tests in existing wells
4. Vertical extension of the reservoir	Distributed strain sensing (DSS) and geodetic techniques (levelling, GPS, InSAR)

5.3. Interpretability, Exclusivity, and Representativeness

For the field test, a Design of Experiment approach is adopted to test pre-specified hypotheses. For example, a hypotheses that corresponds to the test objective A (Table 5.2) is "the local pore pressure increase at the injection well of X bar will result in a significant increase in seismic activity rate". In the Design of Experiment approach, both statistical and geological knowledge are needed.

For any experiment to be successful, the following needs to be considered:

1. Interpretability: It is imperative that there is baseline seismic activity to detect a trend change in the variable(s) of interest over and above the noise random variability that is inherent to the system. The higher the ability to detect such a trend change, the higher the statistical power of the test.
2. Exclusivity: We want to be able to assign the outcome of the experiment, such as a trend change in variable of interest, to the experimental manipulation. Thus, it will be necessary to be able to distinguish with confidence the effect of the experimental manipulation from possible other factors. We refer to these other factors that may, apart from the experimental manipulation, also explain the observed outcomes (or part of the experimental outcomes) as "confounding factors".
3. Representativeness: We want to know to what extent we will be able to generalise the outcomes of the experiment to other locations or parts of the Groningen field. Extrapolation on pure statistical grounds will require a large number of tests. Therefore, extrapolation will require a geological understanding of the mechanisms of seismicity induced by a pore pressure increase.

5.4. Wells and Facilities Concepts

The fastest and simplest way of conducting an injection test is to use Groningen gas from the Groningen ring line and route it through the existing production compressor to existing wells for injection. The modifications would be limited to manifolds, additional piping, and minor control system configuration changes. If wells are in good condition, no additional downhole modifications would be required. The required facilities modifications are shown in Figure 5.3.

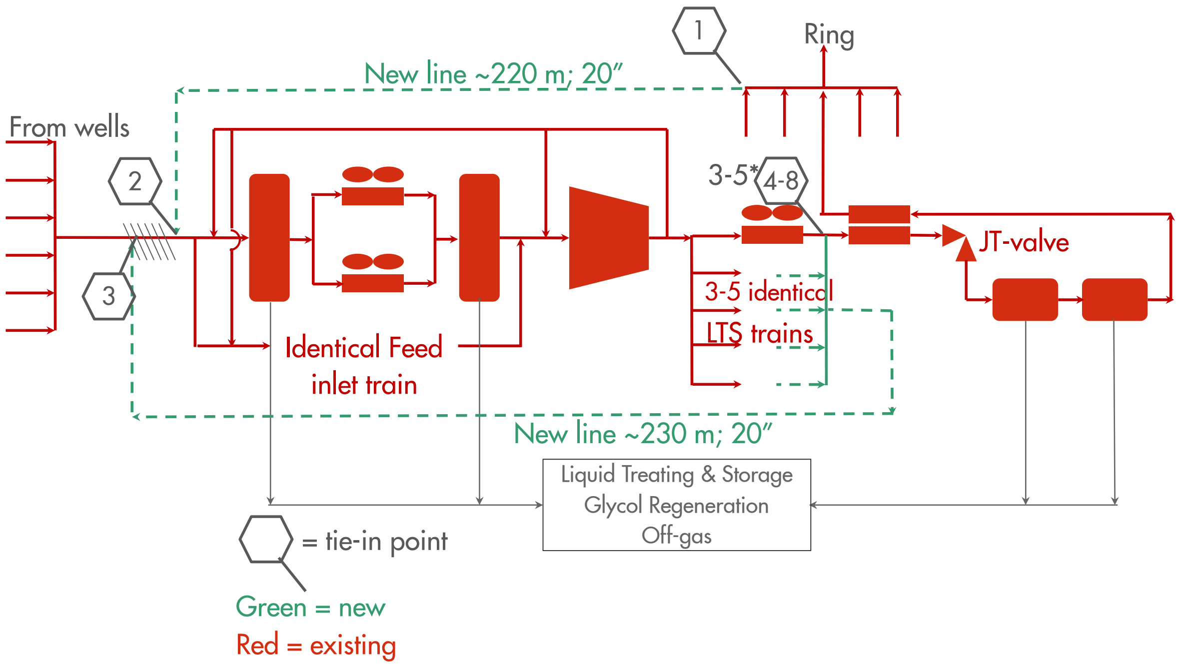


Figure 5.3: Simplified flow diagram of required cluster modifications.

Dry Groningen gas can be taken from the Groningen ring (tie-in 1, ref. Figure 5.3) via a new line to the compressor knock out drums (tie-in 2), which need to be separated from the well inlet manifold (between tie-ins 2 and 3). The compressed hot gas can be directed via the existing lines to the compressor discharge air coolers at each low-temperature separator train; these trains need to be isolated from the compressor discharge system and the Groningen ring. The cooled gas can be sent to the wells' inlet manifold by a new line (from tie-ins 4-8 to tie-in 3). No hardware modifications to equipment outside the cluster are expected to be required.

The existing depletion compressor is at the core of the process. As the process conditions of the suction side of the compressor hardly change (current suction pressure is around 58 bar and ring pressure is around 60 bar), no major changes to the compressor are envisaged. Without changes, the installed compressor driver power limits the flow rate that can be injected into the reservoir. The maximum injection capacity is 6.6 bcm/a, limited by 23 MWe at 90% rotor driver power. Using existing compressor capacity controls, the minimum injection flow is about 2 bcm/a. For lower injection rates, an additional recycle line and flow control from tie-in 3 to tie-in 2 may be required. Minor modifications to the compressor control software and safeguarding may be required to run the cluster in isolation of the Groningen field in this mode of operation.

5.5. Potential Injection Locations, Rates, and Durations

A 20-bar increase over an area of about 10 km^2 can be achieved by injecting for multiple months at a rate of 5 bcm/a in the southern clusters. A 30-bar increase will be challenging, as it requires second-stage compressions and longer injection times. Figure 5.4 shows the maximum pressure increase after injecting 5 or 8 bcm/a, respectively, in a single cluster for an entire year.

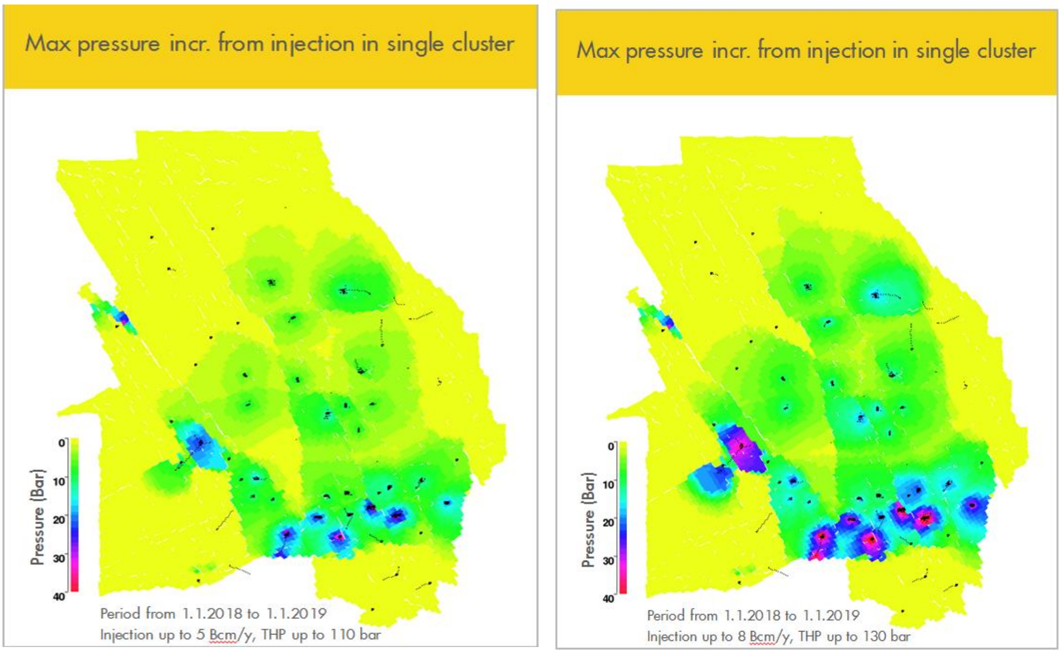


Figure 5.4: Field maps showing an overlay of the simulated pressure increases that can be achieved by injecting 5 bcm/a (left) or 8 bcm/a (right) in each production cluster individually, while all other clusters continue producing. The injection is assumed to last for the entire year 2018. (Note that the maximum technically achievable injection rate for each cluster is only approximately 7 bcm/a.)

5.6. Risks and Mitigation

In the design of an injection test, consideration needs to be given to health, safety and environmental (HSE) risks. The most evident risk related to the injection test is the risk of injection-induced seismic activity potentially leading to nuisance, building damage, and/or injury. This risk can currently not be quantified, given that – as described in chapter 2 – no suitable field data, analogues, or predictive models exist to describe injection-induced seismicity in a strongly depleted field like Groningen.

Consideration should be given to what level of testing is required for which GPM concepts. The risks of a test need to be weighed against the potential benefits of GPM.

The three test objectives described in section 5.2 have different risk levels of induced seismicity. The higher the pressure increase and the larger the area with increased pressure, the higher the risk would be. A potential risk mitigation measure would be a staged testing approach, which starts with the lowest-risk test and only continues with the next-higher-risk tests if the previous test shows no adverse effects.

The simplified “bow tie” in [Figure 5.5] visualises the hazard/threat of injection (left-hand side) that could lead to a top event – in this case increased seismicity – and the potential consequences (right-hand side) such as nuisance, building damage, and injury. The figure also shows, on the left-hand side, possible barriers (1, 2, 3) to reducing the likelihood of the threat causing the top event and, on the right-hand side, the possible barriers to reducing the severity of the potential consequences.

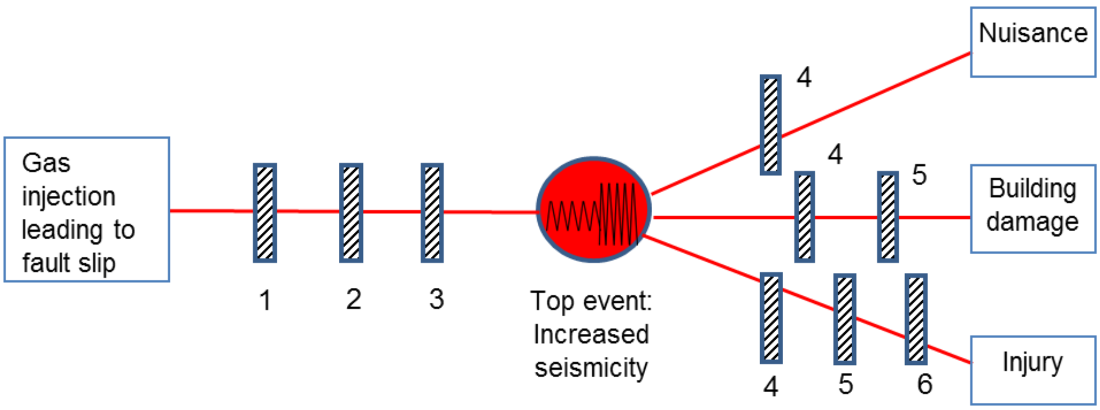


Figure 5.5: **Bow tie for injection-induced seismicity during injection test.**

5.7. Discussion

Further work on the potential field test needs to focus on two key topics, both related to geomechanics: the representativeness of a test in one location to other locations in the field and the additional hazard introduced by a test. The following Table 5.3 provides an overview of the range of possible views. A resolution would require evidence for or against each view.

Table 5.3: **Geomechanical uncertainties reflected in views against and in favour of an injection field test.**

Topic	Against a test	In favour of a test
Representativeness - areal	Geomechanical properties and stress states vary unpredictably over field and extrapolation of test results from any tested location to any other location is not possible. GPM cannot be de-risked other than by implementing GPM step-by-step and testing each injection location.	Geomechanical properties and stress states vary unpredictably over field; however, trends (injection generally causes additional or reduced seismicity) should be consistent over the field and one test thus may provide valuable information.
Representativeness - mechanism	Effect of pore pressure increase is only one of many more possible effects; temperature and other unknown effects could play a role. The field test can only capture “part of the reality”, so its results are unreliable in their own right, and give no insight into the mechanism.	Injection test would mimic the actual GPM parameters (pressures, temperatures). Acoustic and rock mechanics data would increase understanding of the mechanism in reservoir and at faults to the degree that lateral extrapolation is warranted.
Safety: Maximum magnitude of injection-induced seismicity	Faults are critically stressed, they present a highly unstable system that is easily perturbed; therefore, large-magnitude earthquakes from a test cannot be excluded.	Observations in UGS indicate that seismicity under injection is below 1.5 on Richter scale, and only occurs after at least a 60 bar increase in pore pressure. Injection may well increase the total horizontal stress on the faults, making them more (rather than less) stable.

Regarding the risk of injection-induced seismicity, a scientific consensus on its quantification would have to be achieved before implementing an injection test. If the risk of a test triggering unwanted seismicity could be shown to be tolerable, GPM concepts could be envisaged that would include individual, sequential testing at all future injection locations while the project is being implemented. This would circumvent the uncertainty around representativeness. In this step-wise approach, the injection concept would only be fully implemented if all locations have positive test results. Otherwise, if too many locations show negative results, the concept would be left unfinished and only partially operated or completely abandoned. This option of a step-wise implementation is yet to be worked out in more detail.

6. Facilities and Wells Concepts for Injection

6.1. Injectant Choices

Various injection fluids were considered. The most import criteria upon which to judge feasibility are:

- Abundance and availability given the required injection rates of potentially 10-30 bcm/a (30-80 mln m^3/d), depending on injection concept
- Health, safety and environmental considerations related to the injectant composition and the facilities to produce the injectant
- Compatibility with the rock, water, and hydrocarbon gas in the reservoir (geochemistry)
- Compatibility with existing installations (wells, production facilities, and pipes), as the injectant has to be expected to travel from the injectors through the reservoir to the producer wells
- Compatibility with sales gas specifications
- Energy required and cost to manufacture and compress the injectant and – if required – to remove it from the produced gas

For all injectants (except for water), a delivery pressure of 140 barg at the facilities' battery limit has been assumed. Based on their abundant presence and low chemical activity (safety, environmental, geochemistry), only the following injectants have been considered:

1. water
2. air
3. N_2 - from air or flue gas
4. pure CO_2 - from flue gas
5. a combination of the above.

The option of pure N_2 is deemed technically feasible, while water, air, and pure CO_2 have been shown to be unfeasible. The feasibility of generating, injecting, and back-producing combinations of N_2 and CO_2 (either obtained separately from different processes or directly from flue gas) are deemed technically feasible; however, geochemical and geomechanical risks remain, including the capacity of the reservoir to scavenge O_2 and other contaminants and to accommodate CO_2, including the possibility of chemically induced seismicity [3].

6.1.1. Water

Water, although available in abundance, was ultimately deemed technically unfeasible. Firstly, a voidage replacement scheme with water would require a water injection rate of 1-2 mln m^3/d, which if injected under reservoir fracture conditions would need 100-250 wells. From a geomechanical point of view, fracturing is not desirable. Injection at pressures below fracture conditions would need 650-1,300 injection wells, which is about two to four times the number of wells drilled in the Groningen field to date (350 wells) and therefore impractical in view of the surface requirements for drilling locations, rigs required, and water pipelines. Sourcing this amount of fresh water is also not possible and, to prevent souring of the reservoir, utilisation of seawater would require world-scale water treatment facilities. Water that is introduced to the reservoir would be back-produced, which would likely require well interventions to install velocity strings or gas lift to bring the well fluid to surface. Furthermore, as the produced water will be saline, a significant extension of water handling and disposal capacity would be needed on the Groningen clusters.

Secondly, water injection at large scale requires water to be injected close to faults, which very likely increases the risk of earthquakes. Thirdly, given that a water front moving through the reservoir would trap gas at saturations of about 26% (trapped gas saturation), introducing a water injection scheme would be at the cost of at least 26% of the remaining gas, assuming a perfect water flooding of the reservoir (i.e. without bypassing of free gas).

6.1.2. Air

Injection of air was also ultimately deemed technically unfeasible, as it introduces high levels of O_2 into the entire system – the reservoir, the production wells, the surface pipelines, and the facilities. Neither the loss of containment risk due to corrosion of facilities nor the risk of explosive mixtures being present and igniting either on the surface, in wells, or in the reservoir can be adequately managed.

Although the reservoir may have some scavenging potential, this should only be considered for low O_2 content of the injectant (possibly up to several percentages).

6.1.3. Nitrogen

N_2 is available in large quantities and can be sourced from air or from flue gases. N_2 is a miscible gas, which is inert and non-corrosive. Therefore, no special metallurgy measures are required to avoid corrosion of pipelines, wells, and facilities. In fact, N_2 is already present in significant quantities (14%) in the Groningen gas.

As N_2 is less compressible than Groningen gas and other injection gases, it provides a higher volume at reservoir conditions per standard volume of N_2 injected than any of the other injection gases. Therefore, it has the lowest volume requirement for pressure maintenance. After breakthrough of the N_2 in the production wells, it was assumed that the excess N_2 above the in-situ concentration of 14% will need to be removed again to bring the produced gas back to sales specification. N_2 injection for EOR and EGR is being successfully applied commercially.

6.1.4. Pure Carbon Dioxide

Injection of pure CO_2 has been considered as an opportunity to combine pressure maintenance to reduce seismicity and at the same time reduce the Dutch greenhouse gas emissions by ultimately sequestering large amounts of CO_2 in the field. However, the required large amount of CO_2 would have to be sourced from various power stations, and all power stations in Eemshaven (Table 6.1) would only provide sufficient CO_2 for the smallest injection scheme (10 bcm/a natural gas). As well as insufficient availability of CO_2, a pure CO_2 injection scheme is not feasible due to the impact of the returned CO_2 on all of the existing wells and facilities, which are estimated to be able to handle only 16% and 5% CO_2 in the produced gas stream, respectively.

Table 6.1: List of power stations in Eemshaven.

Operator	Name	Fuel	Start-up
RWE/Essent	Eemshaven	Coal	2014
GDF Suez/Electrabel	Eemscentrale	Gas	1996/97
NUON	Magnum	Gas	2013

6.1.5. Combinations (Nitrogen and Carbon Dioxide)

A combination of N_2 and CO_2 (with concentrations of up to 16% in the produced gas stream) is a potentially technically feasible option; however, further work would be required in the areas of long-term containment, operational models, and regulations regarding CO_2 co-injection without repressurising the Groningen field, as would normally be the case in more projects for pure CO_2 storage. There are two ways to create an injectable mix: by direct capture, treatment, and injection of flue gas (removing impurities and excess of O_2) or by production of N_2 by an ASU and spiking in CO_2 captured from flue gas. The power stations in Eemshaven (Table 6.1) could provide the flue gas and/or CO_2. Given the age of the facilities, only the RWE/Essent coal-fired power plant, the Vattenfall/NUON gas-fired power plant, and a hypothetical new purpose-built gas-fired power plant have been considered as flue gas sources. Typical flue gas compositions are shown in Table 6.2.

Table 6.2: Typical flue gas compositions from a gas-fired and a coal-fired power station.

Flue Gas Components	Gas-fired Power Station (NUON)	Coal-fired Power Station (RWE)
N_2	74.82 vol%	76.23 vol%
CO_2	4.11 vol%	16.07 vol%
H_2O	8.15 vol%	4.06 vol%
O_2	12 vol%	2 vol%
Ar	0.92 vol%	0.91 vol%
NOx	10 ppmv	60-200 mg/Nm^3
SOx	None	40-200 mg/Nm^3
Hg	unknown	Unknown
Particulates	None	~ 3 mg/ Nm^3

Direct use of flue gas eliminates the separation of N_2 from air or CO_2 from flue gas; however, this concept lacks the flexibility to control the CO_2 content of the injection stream, as opposed to the option of co-injecting CO_2 captured from flue gas with pure N_2 obtained in an ASU. The flexibility would allow increasing the CO_2 content with time and thereby transitioning to a CO_2 storage scheme when production requirements diminish.

6.2. Process Overview

A conceptual process overview for pressure maintenance is shown in Figure 6.1. On the injection side, as discussed in the previous sections, the feasible or potentially feasible injectants are pure N_2 or a mixture of N_2 and CO_2, with the CO_2 concentration at a level that would still allow using existing wells and facilities. The injectant would be sourced from the air and/or flue gas, air cryogenically separated and optionally CO_2 captured from flue gas to be co-injected with pure N_2 from cryogenic air separation.

In all cases, the injectant would have to be compressed and transported through a new pipeline system to the injection wells. A decentralised injectant generation appears suboptimal (increased plot space and visual impact, operability, more equipment). Instead, a centralised facility at Eemshaven in proximity to the existing power stations or in industrial areas in Delfzijl appears more attractive.

To reduce/mitigate injection-induced cooling effects by injecting at ambient temperature, it is possible to omit (part of) the post-compression cooling of the injectant. To transfer hot injectant, pipelines need to be insulated and underground expansion loops created which will make the construction of pipeline system much more difficult. In such a case, operational procedures need to be applied so that only hot gas is injected at injection start-up.

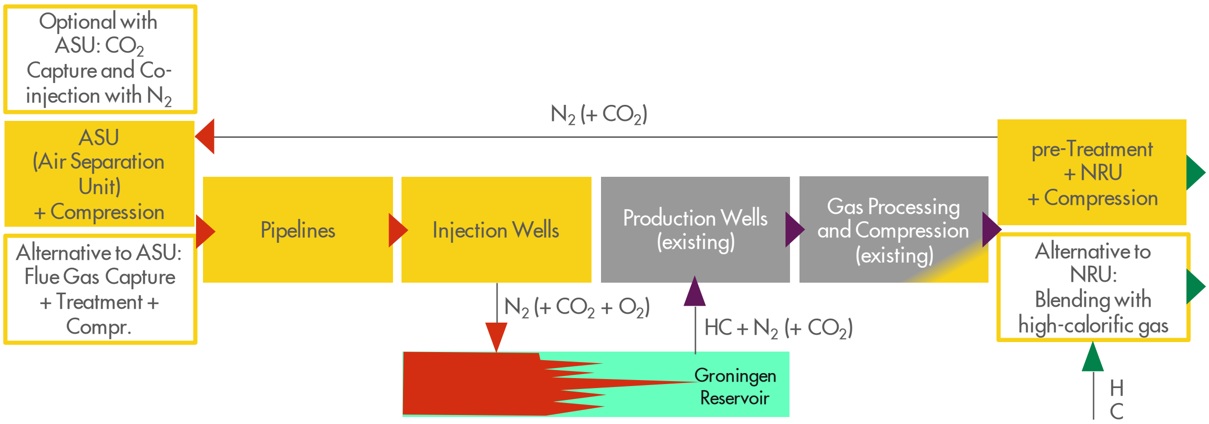


Figure 6.1: Conceptual diagram of a pressure maintenance concept.

Depending on the subsurface concepts (see chapter 4), injection would take place over different numbers and locations of injection wells. As in any injection scheme, the possibility of the injectant reaching the production wells and being produced with the hydrocarbon gas, needs to be taken into account.

On the production side, the aim is to continue using the existing production wells (possibly adding more production wells, depending on the subsurface concept) and to continue using the existing facilities, which serve to knock out liquids and dehydrate and compress the gas for delivery. Some minor modifications to these facilities would be required. Facilities concepts have been developed under the assumption that the field needs to continue delivering Groningen gas quality and therefore, any injection component above the in-situ levels needs to be removed after the current gas processing. Alternatively, if the produced gas only contains elevated levels of N_2 and possibly also elevated levels of CO_2 from CO_2 co-injection (and not other possible contaminants like CO or H_2), then the possibility exists to blend the produced gas with high-calorific gas in the Dutch gas network to obtain the desired Groningen quality. This option is deemed technically feasible and would require minor modifications to the existing infrastructure, but the operational impact would have to be assessed further. However, if the excess N_2 needs to be removed, the additional steps consist of further drying and CO_2 removal before a cryogenic separation of the N_2 in NRUs. Finally, the sales gas is compressed again to export pressure and the recovered injectant(s) are compressed for recycling. Various options exist for siting the NRU, either centrally (for example with the ASU or the flue gas capture facilities) or de-centrally at selected existing production clusters or custody transfer points.

6.3. Injectant Generation

6.3.1. Nitrogen as Base Injectant

If the reservoir scavenging capacity for O_2 was deemed too uncertain to inject traces of O_2 and risk O_2 breakthrough in producing wells and facilities, pure N_2 needs to be generated with O_2 concentration only at ppm levels. In that case, cryogenic air separation is the only viable process. Given the required rates, the air separation would have to take place at the Groningen field and shipping of liquid N_2 from another location would not be feasible). Use of air separation membranes or pressure swing absorption (PSA) have been ruled out. The generation of pure N_2 from flue gas also has been ruled out, as it is far more complex and does not bring significant economic/energetic benefits to offset the complexity.

If a higher O_2 concentration than ppm levels was acceptable in the injection stream (assuming a sufficient scavenging capacity of the reservoir to exclude O_2 breakthrough in the producing wells and facilities), cryogenic air separation is still deemed the best option for N_2generation. Figure 6.2 shows a typical process scheme for an ASU process to deliver high-purity N_2.

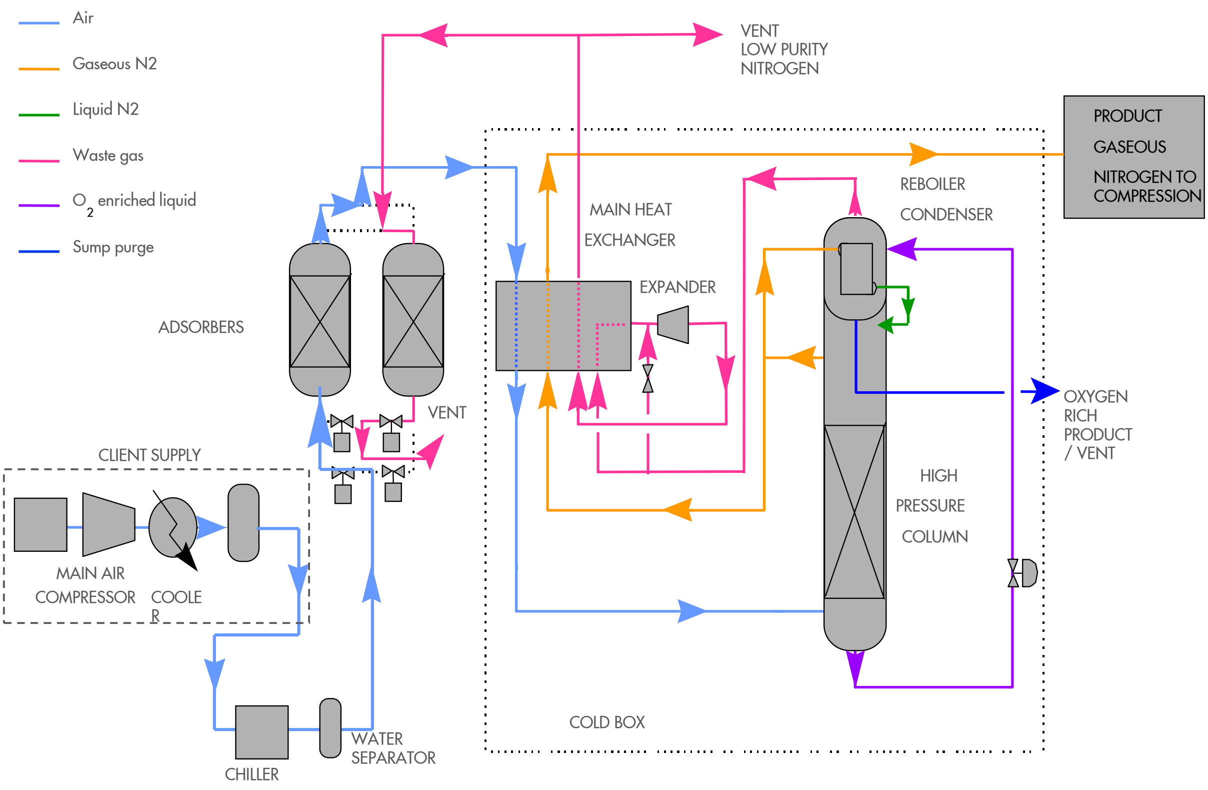


Figure 6.2: **Schematic of a typical ASU.**

6.3.2. Flue Gas as Alternative Source of Injectant

If some level of CO_2 in the injectant is acceptable (in concentrations compatible with the existing production wells and facilities, possibly with some modifications to internals of existing compressors, and some other equipment) and actually desirable (to lower the project's carbon footprint by CO_2 sequestration), the option of using (treated or untreated) flue gas exists. There are several power stations in the vicinity of the field, in Eemshaven (Table 6.2).

As indicated in Figure 6.3, a broad set of potential process technologies to generate clean mixtures of N_2 and CO_2 with (very) low O_2 content have been reviewed.

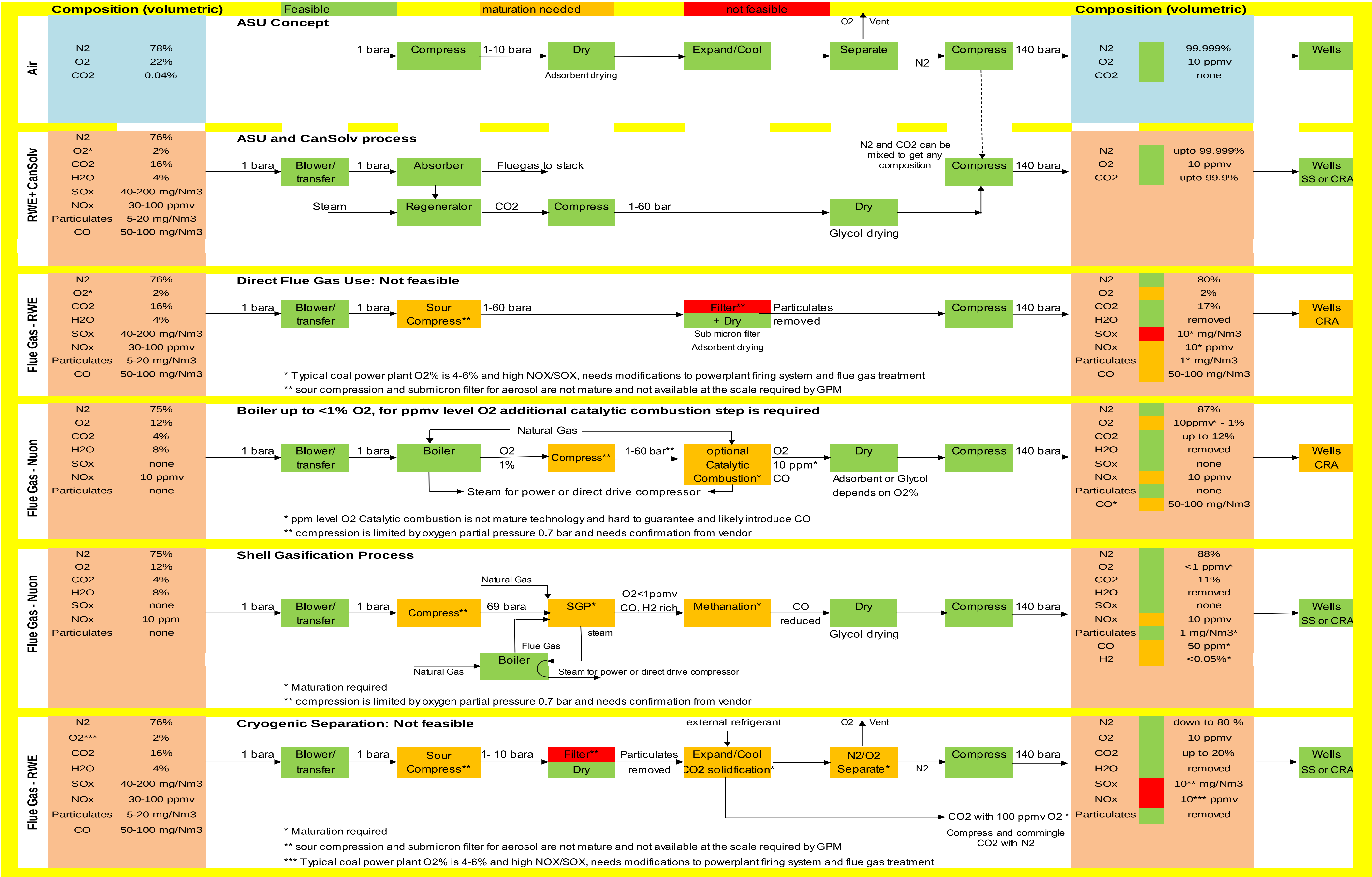


Figure 6.3: Examples for injectant generation processes.

6.3.2.1. CO_2 Capture and Mixing with N_2 from ASUs

Pure CO_2 from a capture process could be mixed with N_2 from ASUs and injected in the Groningen field. This would require one or two fewer ASUs and reduce the greenhouse gas footprint, but it would add a large CO_2 capture plant with its energy consumption to the GPM scope.

In a post-combustion process, CO_2 absorption from flue gas is done by using amines, for example using Shell's Cansolv technology, which is being deployed at commercial scale in the carbon capture and sequestration (CCS) project at Boundary Dam, Canada, and was planned for the Peterhead/Goldeneye CCS project in the UK. As the CO_2 absorption takes place at low pressure, the plot space required for a Cansolv unit is large. An example of a Cansolv unit is shown in Figure 6.4. For GPM, two to four of these units would be required.

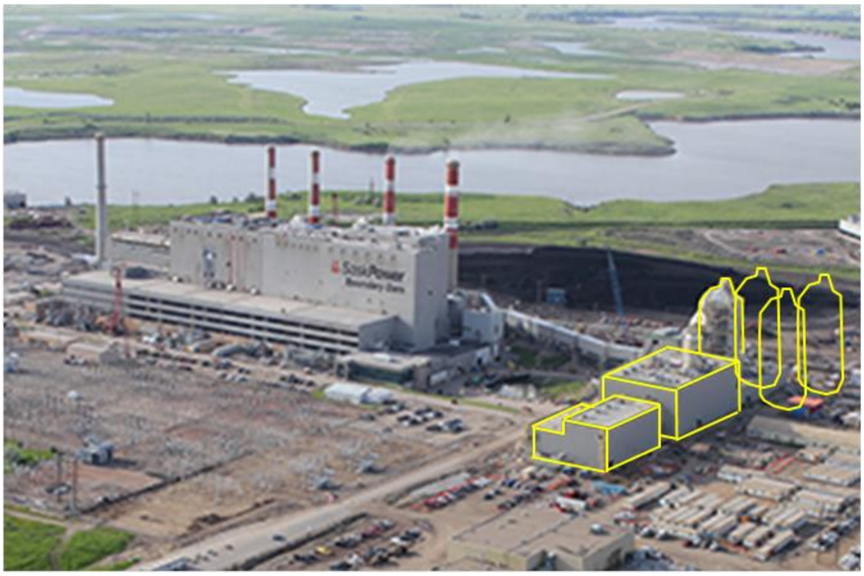


Figure 6.4: Cansolv CO_2 capture plant (outlined) at the Boundary dam power station, Canada. For GPM, additional absorber towers would be required.

To reduce CO_2 capture cost, a synergy could be established between an oxy-firing power plant (modified RWE or Magnum Phase 2) and the ASUs, which can provide the required O_2 for pre-combustion CO_2 capture. However, this would require at least one or more of the ASUs to operate in later field life at full capacity to provide O_2, even when N_2 is no longer required for GPM. Thus, the synergy would be only temporary.

6.3.2.2. Direct Injection of Flue Gas

Flue gas taken from the stack of a gas-fired power plant still contains an O_2 content of about 12-15%. Similar to air injection, which was discarded before, direct injection of flue gas is not feasible as the risk of O_2 breakthrough is not acceptable. In contrast, the low CO_2 content of the flue gas in the order of 4% would be tolerable in existing wells and facilities.

Regarding its O_2 content of only a few percent, flue gas from a coal-fired power plant could be used directly for injection. Also the higher CO_2 content compared to flue gas from a gas-fired power station would be acceptable at levels of about 16%, provided upgrades of the internals of the existing production compressors and other equipment can be made. However, the remaining submicron fly-ash would cause injection well impairment. Furthermore, the SO_x in the flue gas from combustion of coal is very hygroscopic and forms microscopic aerosols with high dew point. Investigations showed that there are no mature and commercial-scale technologies that can guarantee against severe corrosion in wells and transfer lines at 140 barg unless exotic material (e.g. tantalum or tantaline) is chosen. Additionally, the compatibility of other impurities, e.g. NO_x and heavy metals, with the reservoir would have to be assessed as well.

In conclusion, flue gas, whether from gas- or coal-fired power stations, cannot be used directly for injection.

6.3.2.3. Flue Gas from Gas-fired Power Plant - Additional Combustion to Remove O_2

For the flue gas from a gas-fired power station, the higher level of O_2 would have to be reduced, which could be achieved by further combustion in a new boiler. This appears the least complex option with flue gas use. An example of an analogue boiler as required for bringing the O_2 in the NUON flue gas to less than 1-2% is shown in Figure 6.5. The option of building one or more new gas-fired power plants with low O_2 in the flue gas would enable district heating if these power plants could be placed close enough to the heat users, but it should be noted that the local heat demand is low and does not significantly make GPM more efficient.

Catalytic combustion to reduce O_2 from 15% to 1-2% is considered less attractive because the large heat generated in this process will lead to temperatures that are too high for the catalyst, requiring multiple reactor beds with intermediate cooling; the heat removed would require boilers again (for steam and power generation). Catalytic combustion, however, could be considered as to further bring down the O_2 concentration from 1-2% to ppmv level. However, this technology is considered not feasible for coal flue gas due its sensitivity on impurities (SO_x and heavy metals). Furthermore, 5-10 years maturation is estimated as necessary to demonstrate its reliability on low O_2 and CO concentration and operability.

Figure 6.5: Analogue of boiler as would be required to generate 20 bcm/a of flue gas with low oxygen content from the Nuon power plant.

6.3.2.4. Flue Gas from Gas-fired Power Plant Followed by Gasification

In a gasification process, flue gas from a gas-fired power plant can be used for the substoichiometric combustion of natural gas. This will yield virtually O_2 -free injectant gas. This technology is relative complex and has CO as a by-product, which will need to be removed in an additional methanation reaction step. For this specific application, the proprietary Shell Gasification Process (SGP) could be applied but it would require extensive testing and maturation for the use of flue gas as "combustion air". To demonstrate reliability and operability of this technology, three to five years are expected to be required.

6.3.2.5. Flue Gas from Coal-fired Power Plant by Cryogenic Separation

If a lower O_2 content was required for flue gas from a coal-fired power plant, a cryogenic separation process could in theory be employed to separate N_2, O_2, and CO_2 to achieve the required injectant specification. This technology is considered not feasible for GPM because it would need further maturation and would require extensive pre-treatment to remove contaminants and corrosive agents (e.g. SO_3).

The catalytic de-oxygenation described above for flue gas from a gas-fired power station is not feasible for flue gas from a coal-fired power station due to the heavy metals leading to poisoning of the catalyst.

6.3.3. Comparison of Injectant Generation Options

Table 6.3 shows the robustness of various processes for the removal of contaminants to levels acceptable by the Dutch gas specification and for the existing producer wells and facilities.

Table 6.3: Injectant generation options with their ability to achieve desired contaminant concentrations and selection of concepts to keep as an option for GPM.

		Robustness against:				Continue with concept?
		O2	SOx	CO	Operability	
ASU -only	Feasible					Yes
RWE - direct compression	Likely unfeasible, submicronal dust and SOx aerosol removal technologies are immature					No
RWE+ CanSolv+ASU's	Feasible					Yes
NUON+CanSolv+ASU's	very inefficient due to low CO2 in fluegas					No
NUON+Boiler+CanSolv	It is more logical to apply CanSolv to RWE					No
NUON+Boiler	Feasible					Yes
In-field fluegas generation	As NUON+Boiler and enables potential for District Heating					Yes
NUON+Gasification	Feasible but requires further maturation, parked until need for alternative O2 free injectant	O2 free				No
NUON+Boiler+Catalytic Combustion	Not infeasible but requires further maturation, parked until need for alternative O2 free injectant	O2 free				No
Cryogenic separation	Infeasible; confirmed by Air Products					No

It can be concluded that the technically feasible options for the injectant gas are limited to:

- N_2 produced by ASUs
- Flue gas from the Nuon power plant or from purposely built gas-fired power plants; this is the only technically feasible option for the direct use of flue gas
- N_2 mixed with CO_2 captured by a solvent process from a coal-fired power plant.

Gasification and catalytic combustion processes can provide O_2-free injectant but require further maturation and are sensitive to operational up-sets.

For all flue gas processes, it should be noted that:

- The processes that rely on the scavenging of O_2 in the reservoir come with a significant risk of loss in recovery in case O_2 is not sufficiently scavenged when the injectant breaks through to the production wells (see section 6.7).

- These processes have not yet been proven at the scale required for Groningen and would require further maturation of technologies to world-scale size.
- Handling of catalysts/chemicals used and waste (fly-ash, removed contaminants, waste water, chemicals used) need to be considered.

If practically O_2 -free N_2 is required, the least complex process is cryogenic air separation. If CO_2 needs to be co-injected, a combination of cryogenic air separation with a separate solvent process to capture CO_2 from flue gas from a coal-fired power station is less complex than gasification of flue gas from a gas-fired power station.

The advantage of having ASUs and a separate capture of CO_2 is the flexibility to start CO_2 capture after N_2 injection has started, and to vary the CO_2 concentration in the injectant for Groningen but also to dispose of some or all CO_2 at different storage sites.

The hazards and risks related to the various identified injectant generation options are described in section 7.2. In Table 6.4, the health, safety and environmental issues for the different injectant generation options are compared.

Table 6.4: Comparison of health, safety and environmental issues for the different injectant generation options. Colour coding: Dark green - very favourable, Green - favourable, Yellow - less favourable, Orange - not favourable.

	Lowest O_2 (ppm level)				**1-2% O_2**		**> 4% O_2**
Issues	ASU only	ASU + CO2 Capture (RWE)	Nuon + Boiler + Catalytic Combustion	Nuon + Gasification (SGP)	Own Boiler, District Heating	Nuon + Boiler	RWE Direct
Local content for contracting and procurement		as base case	as base case	as base case	potentially more local content due to common equipment boiler, district heating and many small sites	potentially more local content due to common equipment boiler	as base case
Noise	location Eemshaven, noise not expected an issue	location Eemshaven, noise not expected an issue	location Eemshaven, noise not expected an issue	location Eemshaven, noise not expected an issue	may be difficult, especially for compression	location Eemshaven, noise not expected an issue	location Eemshaven, noise not expected an issue
Road transport during maintenance/ operation	low transport during operation, only mole sieves, industrial area, low nuisance from transport, potential for marine transport	fresh amine transport required; requires slightly more transport than in base case	slightly more than base case, but still industrial area, low nuisance from transport, potential for marine transport	as base case (ASU)	transport of chemicals for water treatment, fresh amine, glycol; longer distance for transport through the province	as base case	fine dust filtered out, potential transport of filter cartridges (unless treated on site)
Internal safety (Major Accidents Hazards)	asphyxiation and high O_2 % (fire risk)	CO_2 toxicity + base case	runaway reaction, asphyxiation, potential high CO concentration during upsets	runaway reaction, asphyxiation, potential high CO concentration during upsets	in case of misoperation, potential CO concentration, asphyxiation , boiler explosion	in case of misoperation, potential CO concentration, asphyxiation, boiler explosion	asphyxiation, health hazard exposure to fine dust during filter change-out
External safety (Major Accidents Hazards)	high pressure N2 pipeline, refer De Wijk	as base case + CO_2 pipeline, risk contour around ASU and RWE cansolv+compression	Expected effects are infence, potential for reactor explosion and resulting widespread catalyst dust	Expected effects are infence, potential for reactor explosion and resulting widespread catalyst dust	like base case	like base case	like base case + potential for dust emissions during filter cartridge change-out
Landscape impact: appearance and height of facilities	height > 60m	height > 60m	expected height < 30 m	expected height < 30 m	expected height < 30 m	expected height < 30 m	lower than RWE
Water use - thermal and chemical impact for cooling water, use of fresh water for process	base case	thermal load cooling water higher than base case fresh water required for BFW	thermal load cooling water higher than base case, fresh water required for BFW	thermal load cooling water higher than base case, fresh water required for BFW	thermal load cooling water higher than base case, fresh water required for BFW	thermal load cooling water higher than base case, fresh water required for BFW	thermal load cooling water higher than base case
CO_2 emissions, CCS readiness, CCS implementation, greenhouse gas emissions intensity	Highest; no CO_2 mitigation	lower than base case		negative CO_2 emission	lower than base case	lower than base case	negative CO2 emission

6.3.4. Greenhouse Gas Management

All GPM concepts have a very large power demand, with power requirements of about 700-1300 (MWe) depending on the total injection rate. This is mainly for compression of the injectant gas and produced gas. Generating this power comes with large indirect greenhouse gas (mainly CO_2) emissions.

Without GPM, the ongoing depletion of the reservoir will also require significant electrical power in the range of 300 MWe for second- and third-stage compression, which may be avoided in a GPM case.

Figure 6.6 shows the additional, significant, power requirements of GPM compared to ongoing depletion.

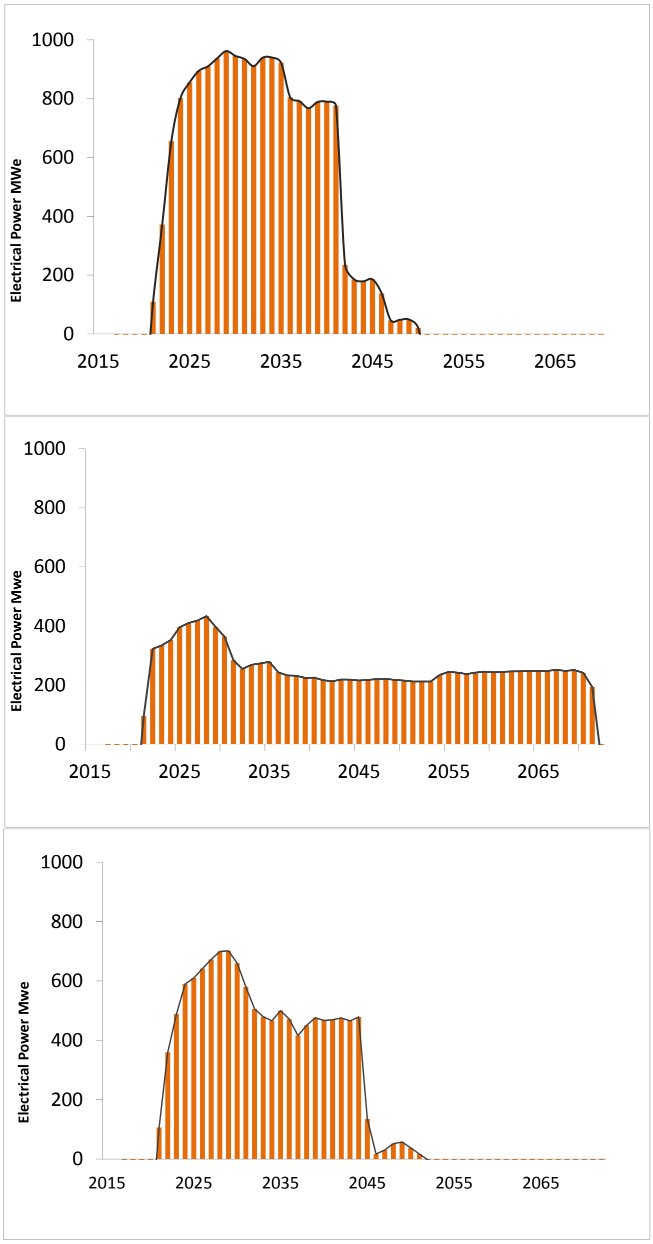


Figure 6.6: Additional power requirements for three typical GPM concepts above the ongoing depletion case. From top to bottom: Dispersed (30 bcm/a injection), Central (10 bcm/a injection) and N-S sweep (20 bcm/a injection).

To manage the greenhouse gas footprint associated with GPM electrical power consumption, the following options have been considered:

- Do nothing: Accept increase of CO_2 emissions for continued production from Groningen under GPM. Use pure N_2 as injectant and minimise risk of corrosion in injection and production facilities.
- Co-inject CO_2 with the N_2 into the Groningen field: Depending on the injectant rate and future injection/production strategy, the GPM emissions can be significantly reduced. In this option, the CO_2 concentration that can be injected is limited to the materials of the producing wells, which allow a maximum 16% CO_2 at 70 barg. Breakthrough of CO_2 requires upgrading of the depletion compressors and upgrading of other equipment (e.g. diethylene glycol (DEG) drying) at the clusters.
- Inject CO_2 into other field(s): In this option, pure N_2 would be injected into the Groningen field, while the CO_2 captured from a power plant would be injected in a nearby field, either onshore or offshore. This option decouples the CO_2 storage from the Groningen production system and is also independent of the Groningen production profiles, allowing a CO_2 capture of the entire power plants' CO_2 emissions also when GPM needs less power. However, offshore CO_2 storage is likely not feasible because of economics and onshore CO_2 storage in the Netherlands is currently not permitted. If onshore storage would be allowed, then long-term containment has to be proven and injection-related seismicity has to be excluded as an issue.

6.3.5. Injection Generation Location

For the ASU location, two large industrial areas above the Groningen field are considered: Eemshaven and Delfzijl. Both locations are considered feasible; however, visual impact, logistics, noise, etc., will have to be considered before a site selection and also exact plot spaces identified. In terms of power supply, Eemshaven is preferred.

For concepts using CO_2 or flue gas, the Eemshaven power plants are the only nearby flue gas or CO_2 sources and CO_2 capture facilities and any flue gas treatment facilities should be built adjacent to the power plant sites. The Nuon Magnum power plant had plot space reserved for an additional coal gasification unit (Magnum phase 2) that is unlikely to go ahead. That space close to the power plants could be available for a new boiler, CO_2 capture, and compression for GPM.

6.4. Wells Infrastructure

The majority of the new wells (injection wells, possibly new observation wells and – for some concepts only – new production wells) will be located on existing wells sites (mostly producing well sites and some observation well sites without production). A few observation wells sites may need to be extended, depending on the concept selected. Most of the identified wells sites are considered as feasible drilling locations. For sites that may anticipate potential permitting issues, alternative sites have been identified. For the new sites and sites where extension is required, the acquisition of additional lands would have to be assessed in further project phases.

In the south of the field, there are multiple production locations which are large enough to accommodate multiple numbers of additional wells. Typically, the distribution of these locations is such that subsurface targets can be drilled from multiple surface locations.

In the north and north-western parts of the field, the existing well and production locations are more sparsely distributed. An initial survey to assess which outstep would be required in the north to access all potential subsurface targets from existing locations showed that a maximum outstep of 3 km would be sufficient.

Table 6.5 shows which completions sizes are feasible for a range of outsteps.

Table 6.5: Well completion evaluation for Groningen reservoir conditions.

Completion Size	"OK to Drill"	"Challenging"	"Technical Limit"
9 ⅝" (big bore)		Vertical	1 km outstep
7"	Vertical or up to 2 km outstep	3 km outstep	4 km outstep
5"	Vertical or up to 3 km outstep	4 km outstep	5 km outstep

A big bore well design (9 ⅝") is technically challenging for a vertical well, considering the possibility of over-pressured sand lenses in the Zechstein formation and drilling through a depleted reservoir with associated hole stability problems. Already with a limited outstep of 1 km, a big bore well design would be at the limit of what is technically feasible.

A smaller 7" completion can handle about 1 bcm/a and can reach all drilling targets within a 3-km outstep. Accepting a challenging completion choice, the 7" well can meet both: the geographic coverage required plus the injections rates with a limited number of wells. On this basis, 7" completion design has been recommended as the base case well for GPM.

A 5" completion can be executed with a larger outstep, yet would require an increased number of wells. A 5" completion design should only be considered for wells with outstep bigger than 3 km.

The proposed well design is illustrated in Figure 6.7.

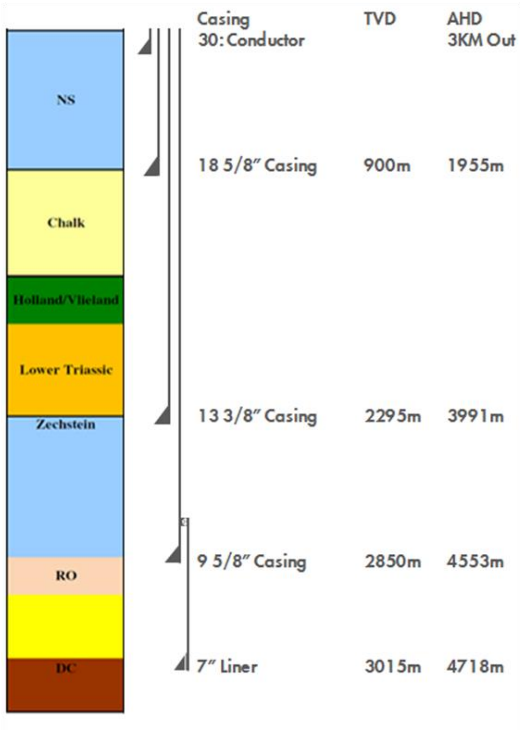


Figure 6.7: Potential injector well design.

For N_2 injection, no special material selection is required and the standard 13Cr material could be used. In the case of co-injection of pure CO_2 with N_2 or in the case of flue gas use, corrosion risks must be considered and managed during operational upsets. During normal operation, the injection gas will be dry; however, during upsets, backflow may occur and therefore, the well completions shown in Figure 6.8 are proposed.

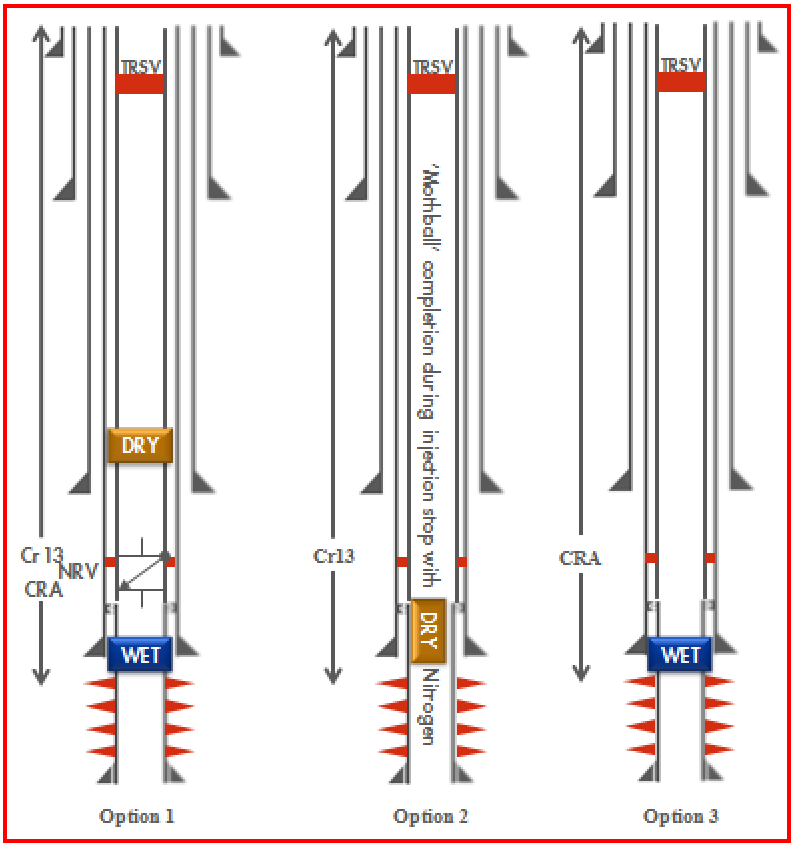


Figure 6.8: Injection well completion options for flue gas and pure N_2 with co-injected CO_2. The injectant is dry; however, during stop of injection, the well completion can be exposed to moisture from reservoir. This requires corrosion-resistant materials. Possible options range from installing (1) non-return valve to minimise the CRA part of the completion, (2) operational measures "mothballing" with nitrogen, or (3) full-length CRA tubulars.

6.5. Gas Production and Treatment

6.5.1. Gas Treatment and Injectant Removal

In case that the amount of N_2 produced with the Groningen hydrocarbon gas with GPM is too high, such that it cannot be blended with high-calorific gas to give the required Groningen gas quality (either because there is not enough high-calorific gas available or the amount of Groningen gas generated through blending is higher than the demand), the produced gas needs to be treated through a N_2 removal facility. The most effective means of removing N_2 from a natural gas stream is by cryogenic separation as this gives the purest separated N_2 stream. The concepts studied envisage recycling the recovered N_2 for injection. The concentration of hydrocarbon gas left in this separated N_2 has a direct effect on ultimate reservoir recovery and therefore should be reduced as far as possible.

Figure 6.9 shows a potential block-flow diagram for a processing facility. The gas treated in the NRUs has an N_2 content of 4% and therefore, some contaminated gas is left untreated and bypasses the NRU to be combined with the treated steam, to give a stream of Groningen gas quality with 14% N_2. The separation of N_2 is achieved by liquefying the hydrocarbon components at pressures of 16-34 barg and cryogenic conditions (-140±5 °C). The N_2 remains primarily gaseous at these conditions and is separated. Both fractions are re-heated to ambient conditions and pressurised to the required pressure level. Upon heating, the hydrocarbon product fraction revaporises. The operation under cryogenic conditions requires the removal of components, which would freeze out and thereby impede with the operation of the unit (blockage, increase of heat-transfer resistance). These components are CO_2 and water.

CO_2 removal is achieved by an amine wash step (acid gas removal, AGRU). Water removal is achieved with a mole sieve de-hydration unit (DHU). Due to utilisation of aluminium equipment in the cryogenic part of the plant, mercury needs to be removed from the gas to prevent corrosion of the aluminium.

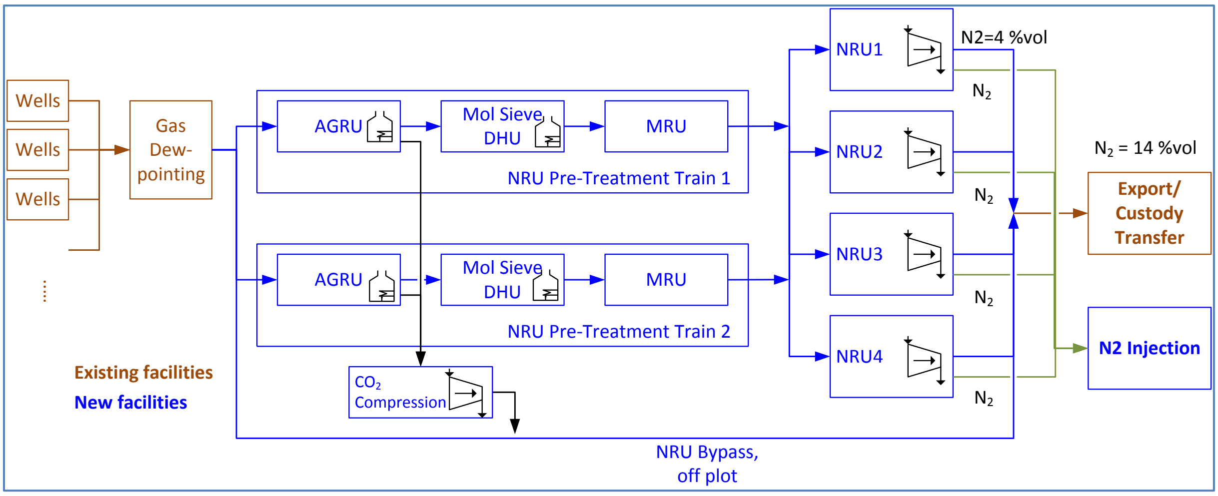


Figure 6.9: **Block-flow diagram for a four-train nitrogen (N_2) rejection unit with two pre-treatment trains.**

The delay between injection and breakthrough depends on the subsurface concept and ranges from 2 to 4 years for a dispersed injection pattern to 5 to 25 years for a N-S sweep pattern. Upon breakthrough, the concentrations of nitrogen will quickly ramp up.

Besides this established technology, upcoming and novel concepts have been evaluated for their potential benefits, namely the application of membranes and the concept of CO_2 freeze-out, resulting in elimination of the pre-treating requirements (CO_2 and water removal). However, the lack of technological maturity of the novel solutions renders these options unfeasible.

Alternatively, to NRUs, it has been investigated whether the produced gas can be blended with import gas to meet the overall Dutch domestic gas specifications. This potentially can avoid the installation of large NRUs and make overall GPM concept more efficient. The Dutch future gas demand requires the amount of N_2 as shown in

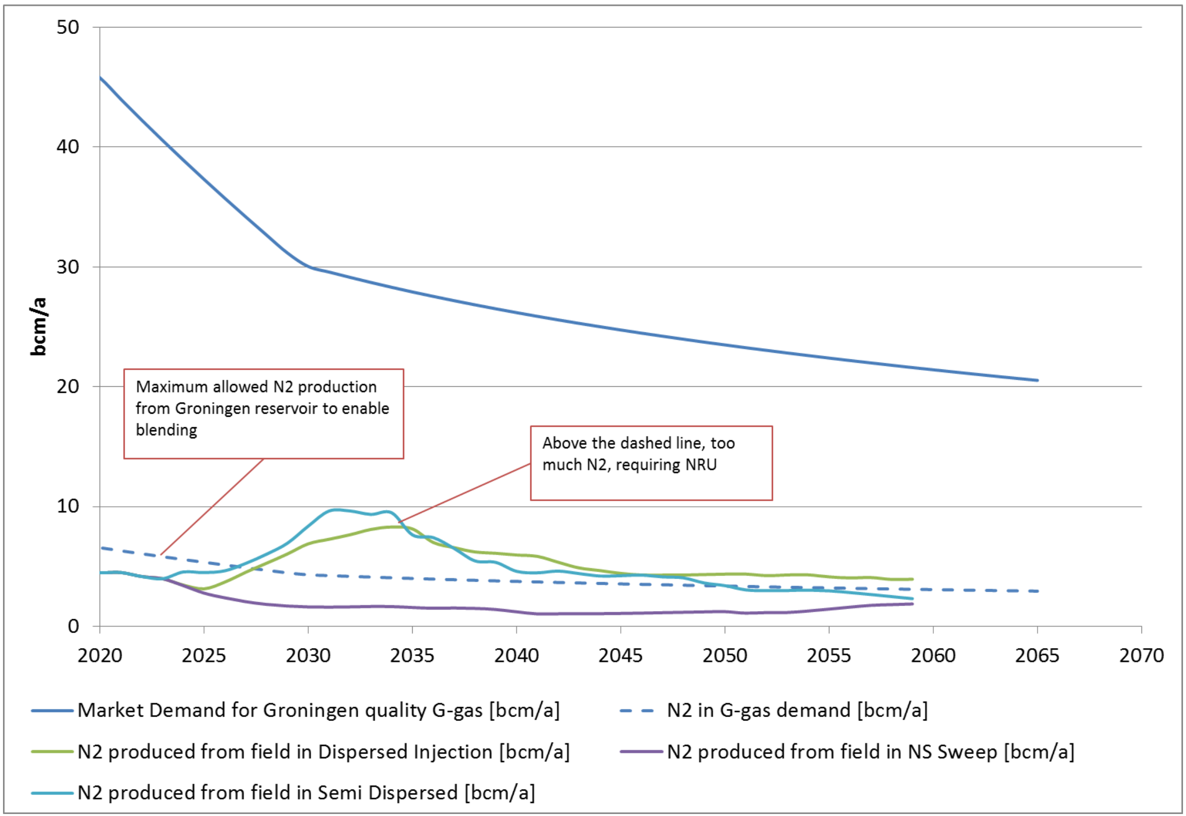


Figure 6.10.

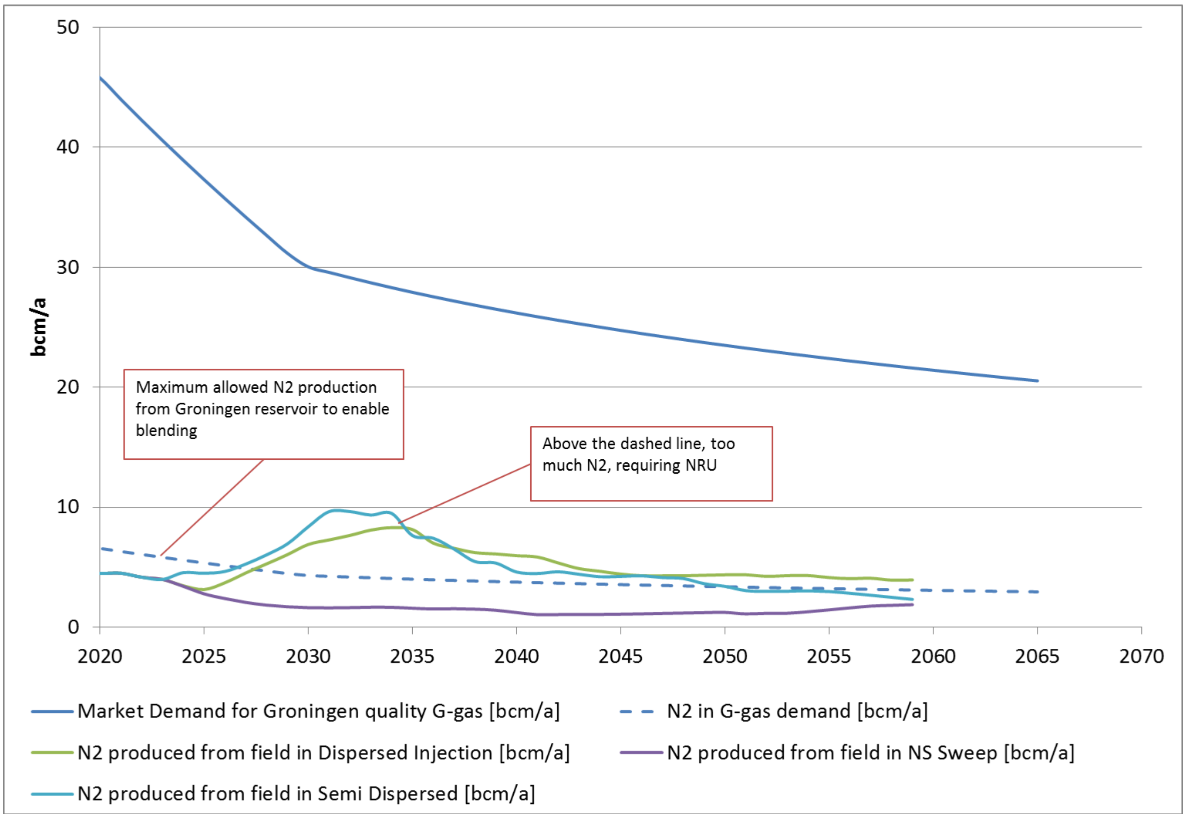


Figure 6.10: Nitrogen (N_2) demand forecast for Dutch low calorific gas compared with N_2 produced in simulated GPM schemes. The maximum allowed N_2 production is

directly related to the Groningen gas demand, which over time decreases. Once N_2 produced from the field exceeds demand, an NRU is required.

Whether blending can be applied depends on the subsurface concept, i.e. the injection and production rates and the injection well pattern and according N_2 breakthrough behaviour, as shown for some sample schemes in

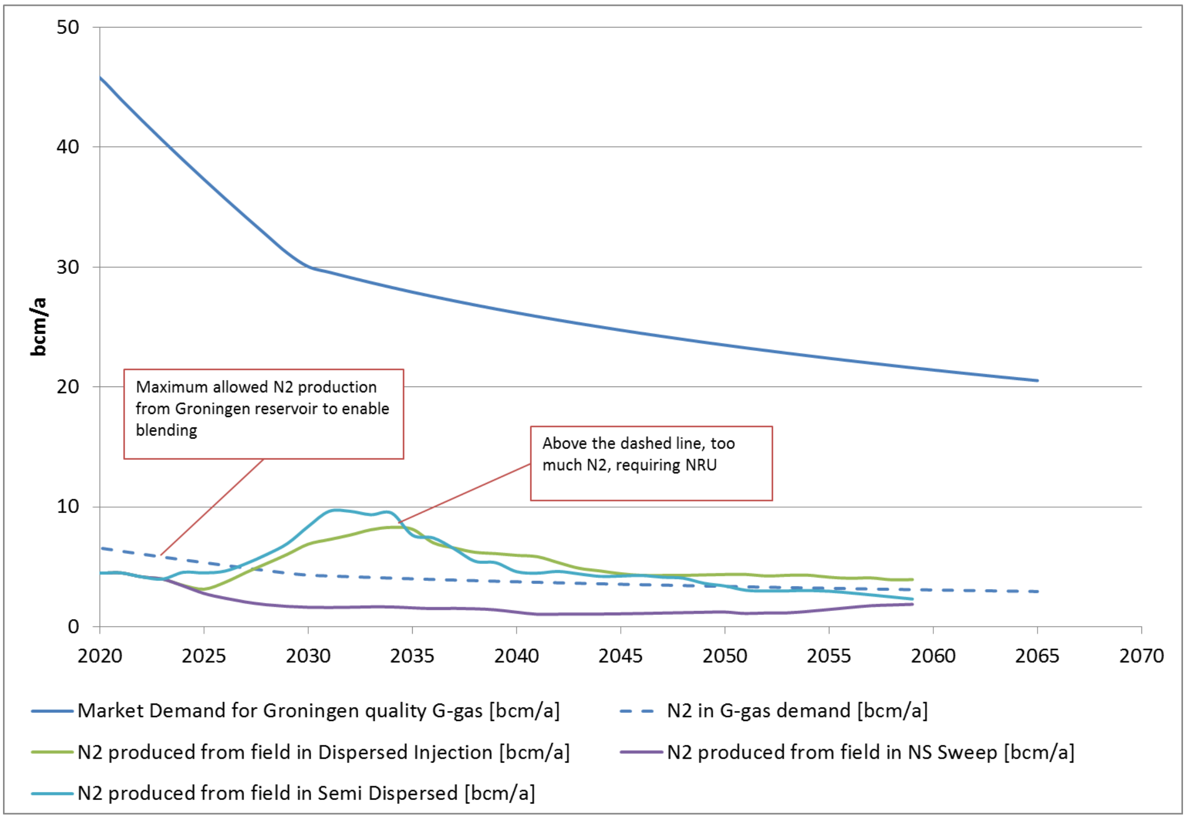


Figure 6.10. As long as the Groningen field produces less N_2 than the demands in the Groningen gas market, it is possible to blend. However, other limiting factors for this option are the CO_2 specification for the gas transport system and the CO specification in case of direct use of flue gas. As dispersed injection patterns have a fast breakthrough of N_2 and accordingly high amounts of N_2 production, blending is not feasible in those types of concepts. Only the N-S sweep and central injection pattern at low rates can provide opportunity to significantly reduce the required NRU capacity by blending. It should be noted that the blended N_2 is not recycled to injection wells anymore and accordingly, more ASU capacity is required to obtain the same injectant rates. The additional N_2 from the Groningen production would replace some of GasTerra's ASU capacity that is provided on a Dutch national level for blending with imported high-calorific gas.

In a GPM scheme, the potential benefits of blending versus ASU+NRU capacity can be optimised, including initial blending up to maximum tolerable limits and later additional NRUs can be installed.

6.5.2. Produced Gas Treatment Locations

To minimise the land use, the visual impact and the noise impact of the additional produced gas treatment facilities, it would be preferable to have one (or two) large, central NRUs instead of smaller NRUs at every existing production cluster as previously indicated in the 2013 Winningsplan GPM concept.

For the NRU, the following potential location options have been identified:

- Eemshaven (industrial area)

- Delfzijl (industrial area)
- Zuidbroek (currently farmland but close to Zuidbroek industrial area and GTS ASU and blending station Heiligerlee)
- Groningen south-East (industrial area)

Eemshaven and Delfzijl are considered feasible locations (see section 6.3.5). Other locations, if needed, would need to be confirmed in later stages of the project. From an integration point of view, grouping ASUs and NRUs in Eemshaven seems a logical choice.

As increasing amounts of produced gas get more and more contaminated with breakthrough N_2 over time, the increasingly more produced gas needs to be routed to the NRUs. For this, new pipelines from the Groningen ring to the NRUs are required. Depending on the injection scheme, the Groningen ring line can be segregated in a non-contaminated and contaminated system thus minimising the total gas flow to the NRUs. This segregation of the ring can be done in phases following the breakthrough pattern.

6.6. Pipelines

For four main injection patterns, detailed pipeline routes have been developed making the best use of existing infrastructure where possible, and the best use of existing pipeline corridors. Figure 6.11 and Table 6.6 show the pipeline scope for all of the concepts. It can be seen that the dispersed injection case has a significant pipeline scope, as does the central injection case despite the limited injection rate.

Table 6.6: Estimate pipeline scope for example injection patterns.

	Injection Pattern			
Pipeline Length (km)	Dispersed (max injection 30 bcm/a)	Central (max injection 10 bcm/a)	N-S sweep (max injection 20 bcm/a)	Semi Dispersed (max injection 20 bcm/a)
Line Diameter < 24"	50	27	0	53
Line Diameter >= 24"	110	57	54	56
Total	160	84	54	109

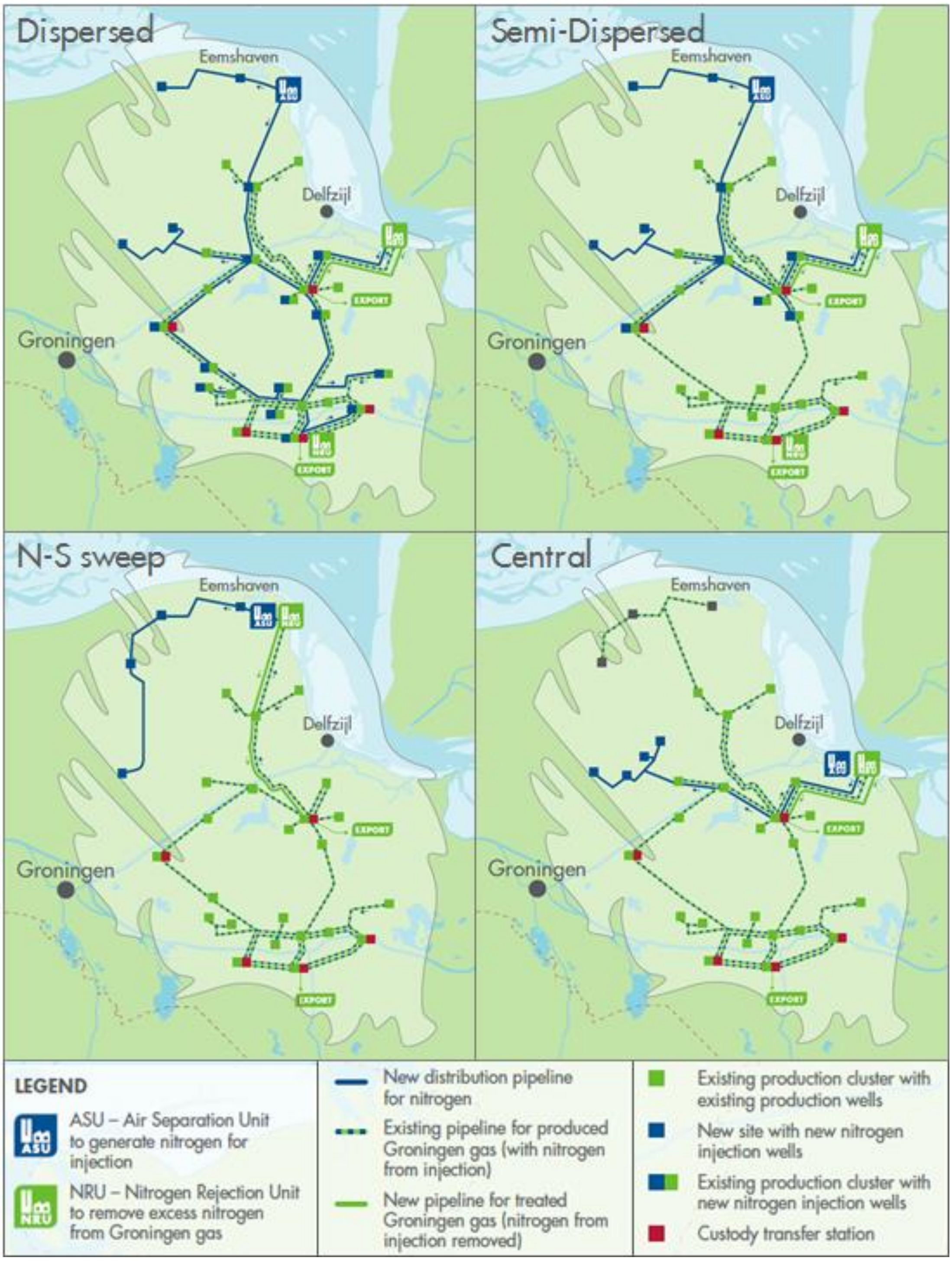


Figure 6.11: Notional pipeline routes for four injection patterns .

The injection pipeline system would be completely new-build and operates at 140 barg and the routing confined to existing pipeline corridors as far as possible. The above schemes are considered archetypes covering a range of potential injection schemes. Based on final optimisation of the required injection rates/locations, other schemes are possible; however, the conclusions will not be significantly different from the above-indicated range of injection schemes.

6.7. Surface Concept Overviews

6.7.1. Injectant Selection as Function of Injection Pattern

The surface facilities concepts are defined by a) the required injection rate, b) the injection pattern and c) the final field abandonment pressure. These parameters determine ultimate recovery and breakthrough of injectant, which determines which injectant can or cannot be used.

For injectants containing contaminants like O_2, CO, NO_x, SO_x the main threat is breakthrough of O_2. It is expected that O_2 gets scavenged in the reservoir but that is uncertain, and will remain uncertain even with extensive testing programmes. If O_2 breaks through, the producing wells need to be shut-in, which would significantly impact ultimate recovery. Figure 6.12 shows the maximum potential loss in UR for three injection patterns in case O_2 breaks through and the facilities would have to be shut-in immediately.

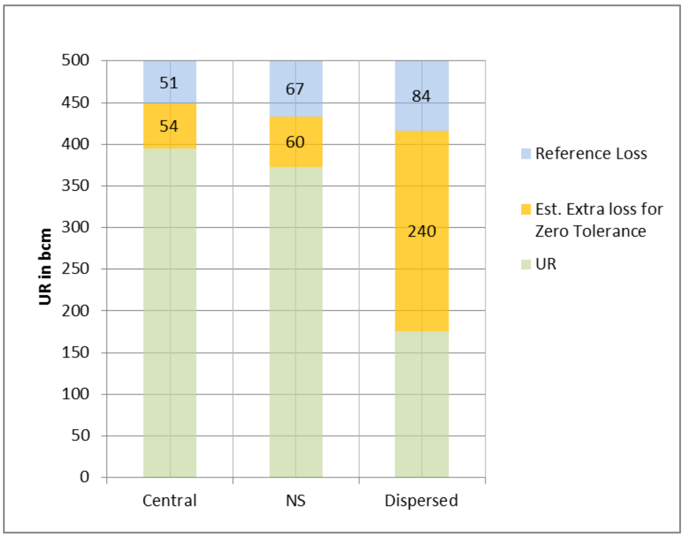


Figure 6.12: Risk of maximum ultimate recovery (UR) loss in case O_2 breaks through and facilities have to be closed-in immediately. The total height of the bars indicates the remaining UR under continued depletion, the light blue sections indicate the UR loss in GPM schemes without O_2 in the injectant, caused by shut-in of producers at elevated N_2 cuts (energetic cut-off), the orange sections indicate the hypothetical UR loss if the producers had to be closed-in immediately at injectant breakthrough, which would be the case if the breakthrough injectant contained O_2 that had not been scavenged while travelling through the reservoir.

From this figure, it can be concluded that, in case of O_2 breakthrough, the UR loss doubles compared to cases without O_2 in the injectant. For a dispersed-type scenario, the risk on UR is clearly unacceptable; this means direct flue gas injection cannot be used in a dispersed-type concept which is in general the scheme which best manages pressure in the reservoir.

6.7.2. Comparing Scope for Flue Gas and ASU Concepts

The main items in GPM are:

1. Compression: For comparable injection rates, there is little to no difference in compression requirements between concepts with different injectants, as gas with roughly the same molecular weight needs to be compressed from atmospheric pressure to about 140 bar.
2. Injectant production (air separation and/or flue gas treatment): Flue gas capture and processing (combustion, catalytic combustion, gasification, or CO_2 extraction) require more capital than air separation alone as more processing units and equipment are required. Further-

more, flue gas concepts will require corrosion-resistant materials for the processing equipment.

3. Wells: For comparable injection rates, the well count is independent of the injectant used. Specific flue gas cases exist in which contaminants will require higher-grade materials. The potential presence of O_2 in particular will require the injection wells to be fitted with high-grade materials completions.
4. Pipelines: For comparable injection rates, the pipeline system is independent of the injectant used. A specific flue gas cases exist in which the potential presence of contaminants like SOx (in RWE flue gas) will require high-grade materials.
5. Produced gas treatment (N_2 and CO_2 removal): Concepts with CO_2 co-injection require more CO_2 to be removed at the NRU, which is not significantly offset by a reduction in NRU size. Additionally, increasing CO_2 concentration in the produced gas will require modifications to the existing depletion compressor and some of the existing gas treatment equipment (e.g. DEG drying).

As flue gas concepts are more expensive than ASU concepts, this higher CAPEX will need to be offset by benefits from efficiency and/or CO_2 stored. With compression energy being roughly the same and produced gas treatment and CO_2 capture requiring more energy, the only real efficiency gain is in the difference in power generation efficiency for a new boiler or the gasification process, which are not higher than commercial power plants. As CO_2 capture from a power plant requires a significant amount of energy, this option is expected to be the least energy efficient.

As there are no obvious benefits for use of direct flue gas, given the additional risks (e.g. UR loss, HSSE) and operational complexity, the GPM work will focus for now on

a) N_2 from ASUs and
b) N_2 from ASUs with CO_2 captured at a coal-fired power plant.

However, the option of flue gas use from a gas-fired power plant remains a potentially feasible option and could be further worked once the injection patterns and rates are defined.

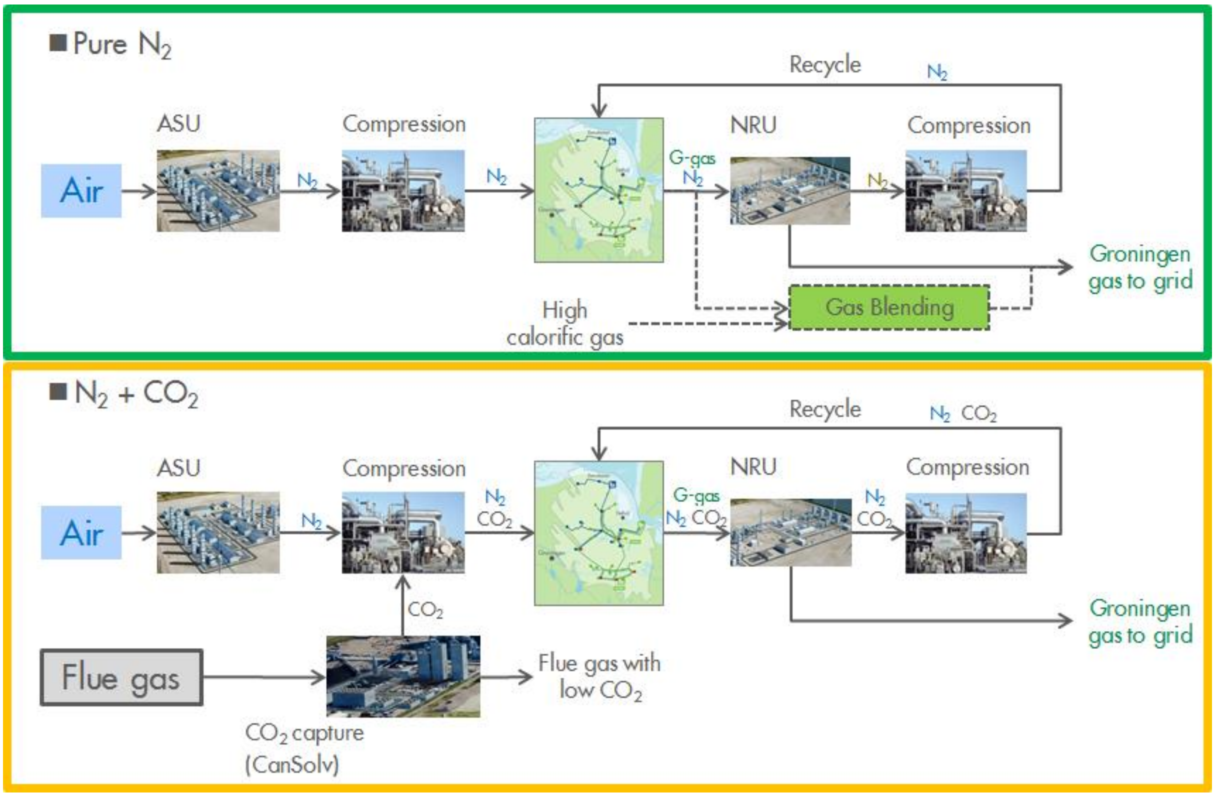


Figure 6.13: The two surface concepts that are expected to be feasible are for pure nitrogen (N_2) and for N_2 with CO_2 co-injection.

6.7.3. Comparing Scope of Continued Depletion and GPM

Under continued depletion, the Groningen field will also require modifications to continue production. As the field further depletes, the clusters will need to be equipped with second- and third-stage depletion compressors. Under GPM, these additional depletion compression stages may not be required, which can reduce the total scope for GPM.

7. Operation of an Injection Scheme

7.1. Well, Reservoir, and Facilities Management (WRFM)

7.1.1. Operations of the Groningen Asset

The existing Well, Reservoir, and Facilities Management plans would have to be updated to take into account the increased operational complexity and increased number of variables to ensure reliable operation, acceptable safety risks and optimised recovery. Manning levels for operations and maintenance may need to be increased to support the operations of new world-scale facilities.

Injection rates, pressures, and temperatures need to be monitored at all injector wells. The current practice of monitoring reservoir pressure from producing and observation wells will have to be continued and intensified and the use of permanent downhole gauges should be considered. Given the required level control of the reservoir pressures around injection, dense and frequent monitoring will be required.

The overall GPM facility design infrastructure would be of a world-scale size and complexity, especially the integration with power plants in the event of implementing flue gas and CO_2 capture concepts.

Currently, seismicity is measured with two deep observation wells and 70 or so shallow geophones and accelerometers at surface. Potentially, this monitoring network might have to be made denser, in particular given the uncertainties around injection-induced seismicity. Subsidence is measured by inSAR satellite, levelling, and GPS stations and compaction by radioactive bullets in observation wells and distributed strain sensing in two new observation wells. Further subsidence and compaction measurements might be required under GPM.

During the GPM injection scheme, injected and produced gas quality will require analysis.

For all injectants, the target O_2 content will have to be closely monitored and in case of CO_2 co-injection, the ratios of N_2 and CO_2 controlled.

Monitoring of composition at well and cluster level to detect injectant breakthrough (gas chromatography - mass spectroscopy) will be necessary. Furthermore, for more detailed reservoir understanding, tracers could be injected into selected injectors and their transport through the reservoir monitored.

Following breakthrough of injectant with O_2 and/or CO_2, the level of well integrity testing would have to be increased.

Once contaminated (N_2-rich) gas breaks through, the gas composition to the Dutch grid (GasTerra) will need to be managed. For example, there may be an opportunity to separate contaminated and non-contaminated gas into two separate rings. If blending of Groningen gas with elevated N_2 content with high-calorific gas is considered, the produced gas rates and quality at cluster and system level will have to be monitored closely.

The Groningen field is used to balance the gap between the demand and the production of the small fields. Therefore, the gas production of the Groningen field varies over time; however, over the recent years the seasonal swing has decreased due to flexibility delivered by the UGSs and the decline in field capacity.

7.2. Health and Safety Risks and Environmental Impact

7.2.1. Introduction

As for any large-scale industrial project, GPM included the potential impact on health and safety of people living near or working at the facilities and the potential impact on the environment needs to be assessed. Identified risks need to be minimised to an acceptable level. Safeguarding and integrity of wells, pipelines, and facilities is paramount. This means ensuring the facilities are well-designed; safely operated; and properly inspected and maintained and – at the end of field life – abandoned to prevent process safety incidents that could place people, the environment, and the facilities at risk.

Specific health, safety and environmental (HSE) risks for GPM facilities/wells have been identified and it can be concluded that the identified risks are manageable and GPM facilities/wells have the means of being operated responsibly.

7.2.2. Surface Facilities Health Risks

The key health issues and risks of the GPM surface facilities are the following:

- Potential health impact on people working or living near facilities, e.g. noise, road transport, light, sleep deprivation, leaks, ultra-low-frequency noise, traffic disruptions
- Additional exposures for people operating and maintaining the facilities: N_2 from leaks, cryogenic burns, O_2 over-exposure, CO_2 from leaks, noise and vibration from compressors, naturally occurring radioactive material (NORM), chemical exposure and handling

These hazards would be managed through the health risk assessment process and adherence to existing laws, regulations, permit (conditions), standards, and guidelines for the design of the new facilities and during operations, including human factors engineering. For example, the existing medical emergency response plan would have to be updated with focussed attention for specific first aid, e.g. asphyxiation, cryogenic burns, compliance with incident classification, and requirements and communication with local emergency services and health care providers.

As for ongoing operations, fatigue risk management and road journey management (shift work and commuting) would have to be considered in particular, given the more extensive spread of facilities across the field.

7.2.3. Surface Facilities Process Safety and External Safety

Process safety hazards of the GPM surface facilities were identified in the Hazard Identification (HAZID) study, including the potential major accident hazards (MAH) listed in Table 7.1. The HAZID technique is a means of identifying and describing health, safety, environmental and social hazards and threats at the earliest practicable stage of a development or venture. In a meeting with an experienced multi-disciplinary team, the hazards are identified using a structured brainstorming technique, based on a checklist of potential HSE issues.

The identified hazards would be taken into account in a future concept ALARP demonstration (“as low as reasonably practicable”) and the Hazards and Effects Management Process (HEMP) would be followed to reduce the risk associated with these hazards to ALARP.

The well sites considered for GPM have been reviewed for potential external safety bottlenecks, using the quantitative risk assessment (QRA) reports for the existing production clusters and the QRA report for the De Wijk EGR project. The gas injection wells would be located mostly on existing production clusters and some existing observation well sites (section 6.4). Based on the external safety/QRA review, it is expected that the contours for a location-specific individual risk greater than 10^{-6}/a for the injection wells sites will not cover houses and/or other sensitive destinations. The injectant generation plant and NRUs for GPM would be located on an industrial area like Eemshaven or Delfzijl; hence the external safety contours are not expected to be an issue for these facilities.

Process safety studies have been identified for possible future study phases to mitigate the major accident hazards risks, e.g. physical effects modelling, QRA, facility siting, hazard and operability analysis (HAZOP), hazard and effects management process (HEMP), and layers of protection analysis (LOPA).

The work so far does not indicate any risks that could not be managed through design and procedures.

Table 7.1: Potential major accident hazards for GPM concepts related to surface facilities and injectants.

Nitrogen-only Injection (ASU)	
• (Hydro)carbons in ASU air intake, leading to explosion • Liquid Nitrogen (LIN): Loss of containment (LOC) of liquid nitrogen leading to O_2 deficient atmosphere, potentially leading to fatalities • LNG (liquefied natural gas): Loss of containment of LNG from NRU, explosive gas cloud leading to fire or explosion, potential multiple fatalities	• Mercury breakthrough from absorber vessels, entering aluminium cold box heat exchangers, leading to corrosion and loss of containment of N_2 and LNG/natural gas. Fire, explosion. • Nitrogen off spec (high O_2 percentage), O_2 in injectant pipeline, injected into reservoir, leading to corrosion of processing equipment; extensive asset damage. • Oxygen rich waste stream from ASU: increased fire risk
Flue Gas Injection and CO_2 Co-injection	
• For cleaning of flue gas from coal-fired power plant; dust from flue gas collected in filters may give rise to dust explosion during handling like shutdowns, filter replacement, loss of containment etc. • For cryogenic separation option: LOC of liquid nitrogen leading to O_2 deficient atmosphere and asphyxiation of people in the hazard zone, potentially leading to fatalities. This risk is similar to the ASU Reference case. • CO_2 is slightly toxic, so upon release of CO_2 effects (like dizziness or even unconsciousness) can occur before O_2 concentration falls to a level where asphyxiation effects occur. • For gasification option: Hydrogen induced corrosion/cracking, leading to LOC leading to fire (invisible flame), explosion. • For gasification option and Boiler option: potential for elevated CO levels in flue gas (toxic levels, above MAC) in case of process upset. • Corrosion issues in flue gas cleaning and injection facilities, including wells, due to O_2, SO_3 (very hygroscopic, forming sulphuric acid; rapid corrosion), SO_2, CO_2 in injectant (in presence of water).	• Unforeseen chemical reactions in reservoir resulting in contaminants in produced gas e.g. lowering of the pH by CO_2 injection and the effects on contaminants. Given the conditions in the reservoir it is very unlikely that H_2S formation by sulphur-reducing bacteria would occur in the reservoir. The heavy metal concentration in the flue gas from a coal fired power plant is significantly lower than the background level concentration of heavy metals (Hg) in the reservoir, so is not expected to influence the composition of the produced gas. • For all concepts with O_2 in the injectant: Water ingress (from the formation) during injection suspension which can lead to corrosion in the lower part of the completion. Potential loss of well, and/or eventually LOC

The qualitative comparison of the hazards for different injectant generation processes shown in Table 6.4 do not allow discarding or preferring any injectant generation concepts based on safety considerations alone.

7.2.4. GPM Subsurface and Wells Risks

Additionally to the hazards identified in the previous section pertaining to facilities and injectants, the nature of the GPM also brings particular subsurface hazards that were also identified in a HAZID and a separate Geomechanical risk assessment exercise.

A particular risk for GPM is injection-induced seismicity. The underlying hazards are:

- Reactivation of existing faults through injection. Risk mitigation is to inject away from known faults and to minimise the pore pressure increase around injectors. The Well, Reservoir, and Facilities Management plan will therefore include injection pressure monitoring.
- Thermal effects in injection scheme. There is a potential risk of thermal effects during injection leading to contraction of rock, which may result in seismic activity. Given that thermal effects appear to be a significant factor in the risk of seismicity (ref. [3]), risk mitigation can be achieved by controlling the temperature of injected gas by heating the gas at surface or control of the rate of injection. Technical implications of controlling the injection gas temperature would have to be evaluated.

Figure 7.1 shows a safety "bow tie", visualising the hazards/threats, related to injection (left-hand side), which lead to a top event – in this case increased seismicity – and the potential consequences (right-hand side). The figure also shows possible barriers to reduce the likelihood of the threats causing the top event.

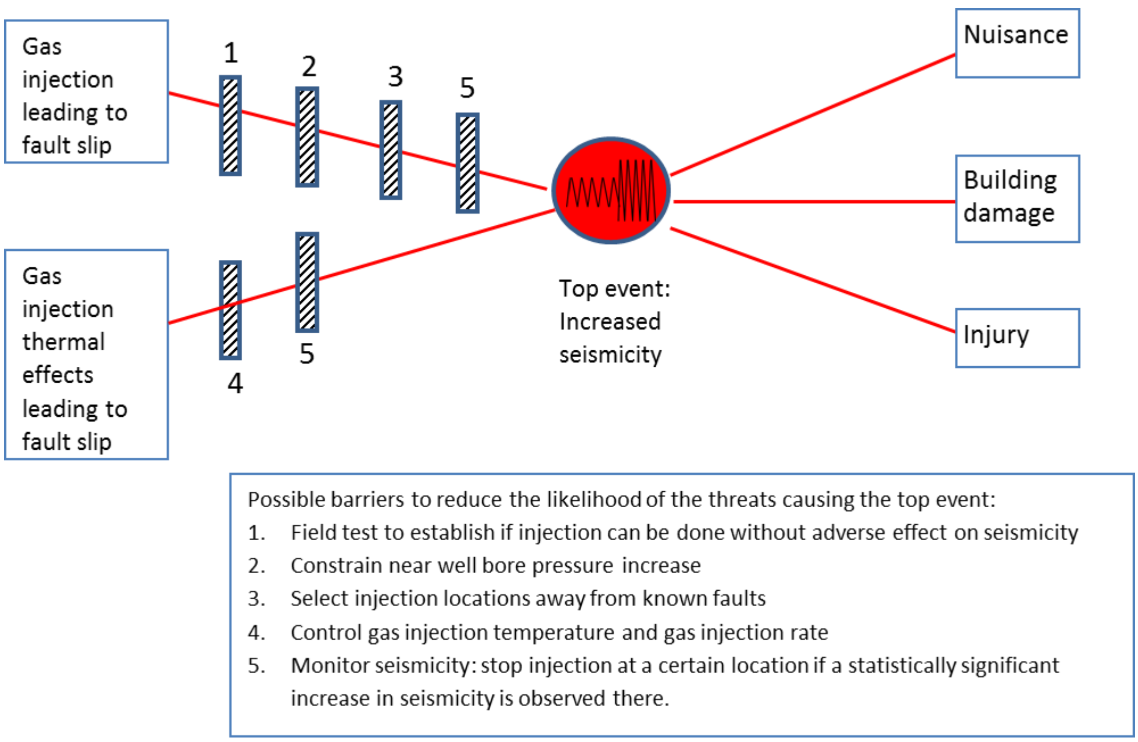


Figure 7.1: Bow tie for injection-induced seismicity.

Other subsurface risks only relevant for concepts with flue gas or CO_2 injection are:

- Leakage in abandoned wells: Five out of 33 abandoned wells have not been abandoned at the reservoir cap rock level. Damage to cement or casing may create a leak path over time. Injection of CO_2 or other reactive flue gas components will speed up the degradation of cement and casing. The risk mitigation possibilities are:

- The Zechstein salts would squeeze against the casings or even close the borehole over time. Furthermore, any water- or hydrocarbon-bearing sands within the Zechstein are at higher pressures and if leaking would occur, flow would be into rather than out of the depleted Groningen reservoir.
- Monitor pressures in wells adjacent to the incompletely abandoned wells to detect communication and leak paths into the monitored wells.

- Failure of producing wells: Mechanical failure of tubular or cement that limits or prevents well operations. The current assumption is the existing wells can already handle up to 18% of CO_2 in the produced stream. However, there is a risk of overestimating the integrity of existing well stock with respect to potential CO_2 corrosion. Risk mitigation possibilities are:
  - Monitor the gas composition of producing wells.
  - More frequent well interventions on wells with detected and elevated CO_2 levels. Shut-in, workover, and replace the producing string and a packer as required.

Onshore CO_2 storage in the Netherlands is currently not permitted, however, for lowering the carbon footprint of GPM, the option of pure CO_2 injection in the Annerveen field has also been reviewed. As for the Groningen field, the Annerveen field also has the Zechstein as cap rock, which is a proven seal. However, the field also has similar subsurface hazards as described above for the Groningen field. Seismicity from depletion has also been experienced in Annerveen. Although the seismicity levels were lower than in Groningen, the risk of seismicity during injection is not necessarily lower than for the Groningen field. The Annerveen field could be repressurised to near virgin pressure (280 barg) for the purpose of CCS, whereas the Groningen field would not go above 80 barg. The higher the pressure increase, the higher the probability of fault slip and seismicity.

7.2.5. Environment

The environment in the Groningen area consists of rural area, small villages, a coastline with the Waddenzee and the estuary of the Eems-Dollard and industrial areas in Eemshaven and Delfzijl. The province of Groningen has areas of protected nature, but all currently producing 20 Groningen cluster locations are located in rural areas, although a couple of these locations have neighbours living within 300 m. A few locations (e.g. Bierum) are near the Waddenzee and the Eems-Dollard, which belongs to the Natura 2000 network of vulnerable habitats in the EU and are classified as IUCN category IV areas.

Table 7.2 shows the environmental issues and risks and a range of mitigation measures that have been identified for the GPM project. Issues related to biodiversity are not expected. The area is well-known and potential project impact on biodiversity/endangered species is anticipated to be manageable based on NAM's project experience (e.g. bird nesting periods' impact on construction timing).

Due consideration was given to the environmental risks and the possibilities to minimise them in the concept development and site identification.

Table 7.2: Environmental issues and risk for GPM and range of mitigation measures.

Environmental Issues and Risks	Mitigation Measures
• **Energy use** (power and heat) and associated greenhouse gas emissions: For the larger injection schemes (20-30 bcm/a), the power consumption is around 1 GW. This would be a significant increase in power consumption and CO_2 emissions on a national level. The carbon intensity of the Groningen gas will significantly increase.	• **Flue gas injection, CO_2 co-injection, and/or CCS** in other fields have been identified as potential options to reduce the carbon footprint of the project (see section 6.3.4)
• **Cooling water** access in the northern part of Groningen has been limited already for the newer industries like IT data centres;	• **Air cooling** is an alternative option if necessary.
• **Noise** exposure around ASU and NRU installation(s) for neighbouring buildings. The compressors – required for compressing the injection and produced gas – are expected to be the main contributor to the noise emission. Another source of noise is air coolers, which are expected to be required if (sufficient) cooling water is not available. • **Visual impact** of the newly built ASU and NRU, especially if located in a rural area with no, or very limited, industrial activity. • **Incidental gaseous releases** (for example CO_2, N_2 and natural gas). • **Light disturbance** at night from the newly built installations.	• **Re-use of existing sites**: The injection wells can be located on existing production clusters or observation sites to minimise land use and visual impact. A few new well sites may be required, depending on the selected injection well pattern. • **Centralised ASU and NRU:** The injectant generation is also centralised at Eemshaven or Delfzijl (in the case of flue gas use: only Eemshaven is possible). The number of NRU installations is limited to one or two, depending on the selected concept. Also these industrial facilities will preferably be located in industrial areas, like Eemshaven or Delfzijl, where they have minimal incremental visual impact, noise and light disturbance. In these industrial areas, land is available for industrial activities.

If it is decided to implement GPM, a formal impact assessment (IA) would have to be carried out as part of the permitting process. Therefore, the impact assessment will follow the formal application process, including the start note “Notitie Reikwijdte en Detailniveau” and formally mandated engagement sessions.

In the design of the facilities, further consideration would have to be given to the environmental aspects like visual impact, noise emissions, and water use, including any additional aspects identified during the EIA process.

7.2.6. End of Field Life Abandonment

The GPM injection wells and facilities do not contain elements that require special abandonment considerations compared to other NAM onshore facilities. At the end of field life, the surface facilities and wells, at the field level, will require to be abandoned in compliance with the Dutch governing body. The abandonment scope will however significantly increase as the number of wells and facilities would have increased due to the GPM project and the reservoir will have a higher abandonment pressure.

8. Development and Implementation of an Injection Scheme

As mentioned in section 1.2, the feasibility of GPM is being studied, but no firm plans exist currently to test or implement such a concept. The following conditions are a prerequisite for GPM to be implemented:

1. Continued production under depletion was deemed unacceptable.
2. The concept of pressure maintenance was proven to be within acceptable safety limits and effective in reducing the earthquakes.
3. One or more field trials to demonstrate the effectiveness and acceptable safety risks has/have been conducted successfully.
4. The remaining gas volumes in the field justified the significant investment.
5. Society and the regulator support this large-scale project.
6. GPM has acceptable economics and is proportional to other alternative risk mitigation options.

Hypothetical schedules have been developed as part of the GPM feasibility study. Estimating the durations for testing, designing, procuring, constructing, and starting-up GPM concepts, helps to establish from which points in time, GPM could be available as a measure to reduce seismicity.

Given the required effort to prove potential feasibility and to execute a GPM project, a start-up of such scheme cannot be expected before the mid-2020s.

Figure 8.1 shows a hypothetical schedule of an implementation of GPM for injection of N_2 from ASUs. This schedule is largely influenced by the following uncertainties:

- pace of technical and scientific progress to better understand the seismicity in Groningen, whether injection is a potential option, and whether an injection test could be designed to safely and reliably inform whether GPM would work
- required time for injection testing – in particular the number of locations that would have to be tested
- decision-making and permitting process – also for an injection test alone – involving many stakeholders, including the public.

The hypothetical schedule makes the following assumptions:

- No wait periods – the implementation is assumed to be continuous, aiming for the fastest possible start-up of GPM. Wait periods could be envisaged if there was no need for a fastest possible implementation and GPM would still be studied and progressed as an “insurance policy” with actual construction and implementation at a far later date.
- Injection testing with hydrocarbons (see section 5.4) – no infrastructure needs to be built to provide large quantities of N_2 for testing.
- Positive outcome from the injection test expected with little impact on selected full-field concept – the frontend engineering and design (FEED) work for the full-field concept already starts during the injection test period; a negative test would bring that work to a hold or require a review of the concept assumptions, leading to a recycling of work.
- Best practical project execution.
- No external constraints.

Given the project size and complexity, a start-up of such scheme cannot be expected before the mid-2020s. For any concept evaluation so far, a first N_2 injection date in 2024 has been assumed. However, it can easily be envisaged that this date gets deferred if the feasibility of GPM and the injection test cannot be demonstrated convincingly in time, the injection test scope becomes much larger (several test sites, longer tests) and typical risks for projects of that size materialise, resulting in delays.

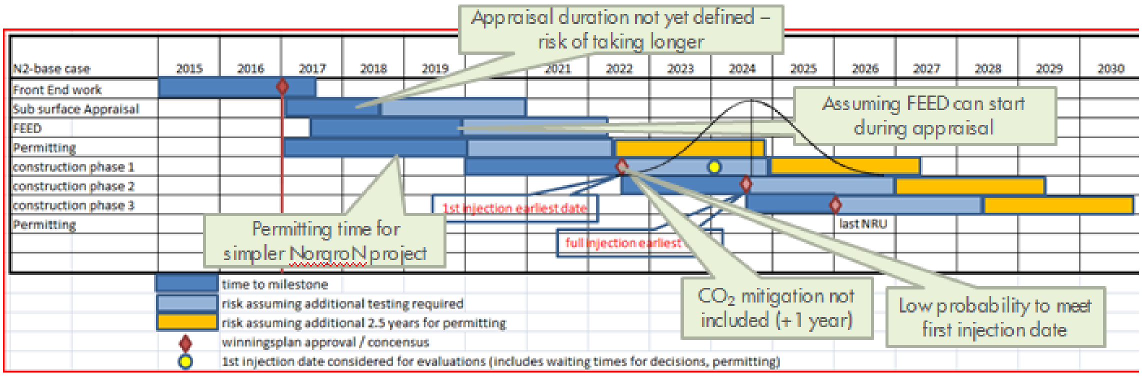


Figure 8.1: Hypothetical project implementation schedule assuming one injection test, showing that first nitrogen (N_2) injection before the mid-2020s is not realistic. Additional time for testing and permitting delays can bring the first injection date easily to 2027.

GPM would be a major project with drilling and construction activities over several years across various sites in the Groningen field. One or two drilling rigs would drill the new injection wells – mainly from existing production clusters. In Eemshaven, several ASUs to generate N_2 from the air would have to be built – or alternatively, a flue gas capture plant linked to the Nuon power plant with further facilities to treat the flue gas (additional boiler and possibly reactors for catalytic deoxygenation). Pipelines would have to be laid across the province, mainly in existing pipeline corridors, linking up the new Eemshaven injectant generation plant with the injection wells. It is also likely that new facilities will be required to remove the injected gas again from the produced Groningen gas. Those facilities would either be built near one or two of the custody transfer points, Tusschenklappen (Zuidbroek location option) and Tjuchem (Delfzijl location option), or at Eemshaven next to the injectant plant. The GPM project will come with logistical issues, which will not vary much for each concept. There are not unsurmountable issues, but there are some considerations to be tackled in the following situations:

- Required logistics for big modules on the least accessible areas (mainly in Zuidbroek, potential NRU location for the disperse case) which have a few more constraints (access, noise, communities) than the other locations
- Road transports for well sites and pipelines will face difficulties, due to narrow roads that will be crossed and villages that will be encountered. Route plans are an important part of the measures to avoid project-traffic clashing and to minimise impact with neighbours and public in general.
- Logistics for NRU and ASU to confirm sea transport options for Delfzijl and Eemshaven locations.

Because of the size of the project, the execution of the project will also come with drilling and construction hazards that need to be managed. These hazards are not different from those of other major oil and gas projects; however, the scale of the project makes this a key element in project planning in order to minimise risk and nuisance to neighbours and workers.

Additional GPM implementation scenarios can be envisaged that consider phased implementation, including "test-as-you-build" of injection wells.

9. Feasibility Assessment of GPM Concepts

As already indicated in section 1.3, an overall GPM concept consists of a number of (technical) elements:

- Pressure management policy defined by reservoir abandonment pressure and tolerances to regional pressure increases and decreases during GPM)
- Injection and production pattern and rates
- Testing/appraisal of GPM before a full-field implementation
- Injection medium
- Type of facilities for a) injection medium sourcing/generation and processing and b) produced gas treatment and/or blending with high-calorific gas
- Project execution planning and phasing.

All of these elements have been discussed in the foregoing chapters. Combining the findings for these elements, preliminary concepts of logical combinations of the pressure management policies, injection and production patterns and testing requirements can be built.

Any given pressure management policy from Figure 4.2 can be achieved with various injection well patterns, for which archetypes were shown in Figure 4.3, that could be further optimised. Assuming that the seismic risk is governed by the pressure management policy, concepts with similar pressure management policies can be compared on other key drivers, like public acceptance, environmental and implementation footprint, gas recovery, schedule, and required project scope.

Depending on the type of pressure management policy – whether pressure increases are acceptable or not – certain injection patterns appear preferable: For cases, in which repressurisation is allowed, the N/S sweep and semi-dispersed patterns appear suitable, while cases, in which repressurisation needs to be avoided, the fully and semi-dispersed patterns appear more suitable. A local injection pattern would only allow low injection rates and therefore, only be suitable to either temporarily stabilise pressures locally or result in a low-rate full-field GPM scheme.

Further optimisation of the GPM cases is possible. Also, other GPM cases with, for example, a continued but slower pressure decrease across the field down to certain abandonment pressures could be assessed.

N_2 injection and N_2 with CO_2 co-injection were both assessed to be technically feasible. The injection medium selection was found to be relatively independent from the applied subsurface concept, except for limitations to blending and different expectations of injection medium breakthrough.

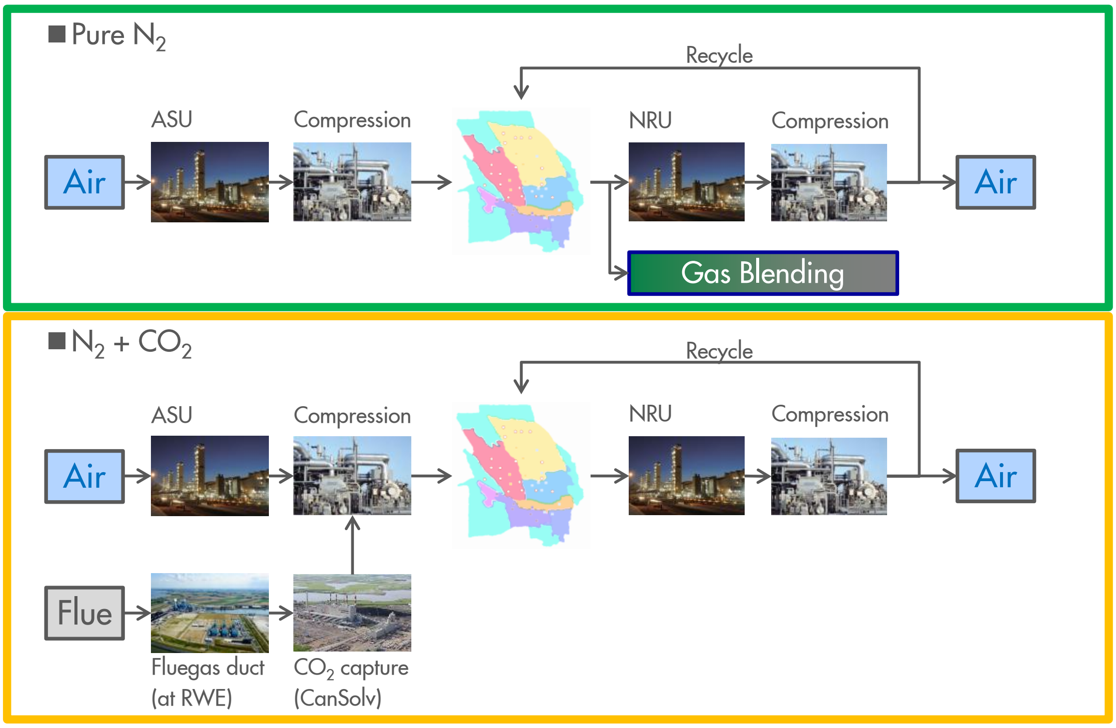


Figure 9.1: The two surface concepts that are expected to be feasible are for pure nitrogen and for nitrogen with CO_2 co-injection.

As indicated in chapter 8, different GPM concepts have similar start dates, given the common scope (wells, compressors, pipelines) and testing and permitting durations. The extent of the injection testing before implementing the full-field concept would influence the schedule. Currently it is assumed that all concepts are impacted in the same way by the testing, but this needs to be assessed further. The currently assumed GPM start date is in the mid-2020s.

Overall, implementation of GPM seems technically feasible, but whether the desired seismic risk reduction can be achieved is yet unclear. Local testing seems technically feasible, but whether appropriate testing can be done to obtain the required assurance that GPM is effective for all the different pressure management policies, and whether testing can be executed with acceptable safety risks, still remains uncertain. Given the issue of possibly low representativeness of injection field-tests, concepts with a step-wise approach would have to be considered, in which appraisal and implementation of the full-field scheme are progressed in parallel ("test-as-you-build" concepts).

Ultimately, to establish feasibility for GPM and injection field-testing, a scientific consensus on how to quantitatively estimate the risk of injection-induced seismicity would be required as well as a cost benefit analysis versus other options to manage seismic risk.

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The reports in this references list prepared by TNO can also be obtained using the following TNO-link:

http://nlog.nl/nl/hazards/subsidence.html (NL) and

http://nlog.nl/en/hazards/subsidence.html (EN).

Appendix 1. Groningen Field

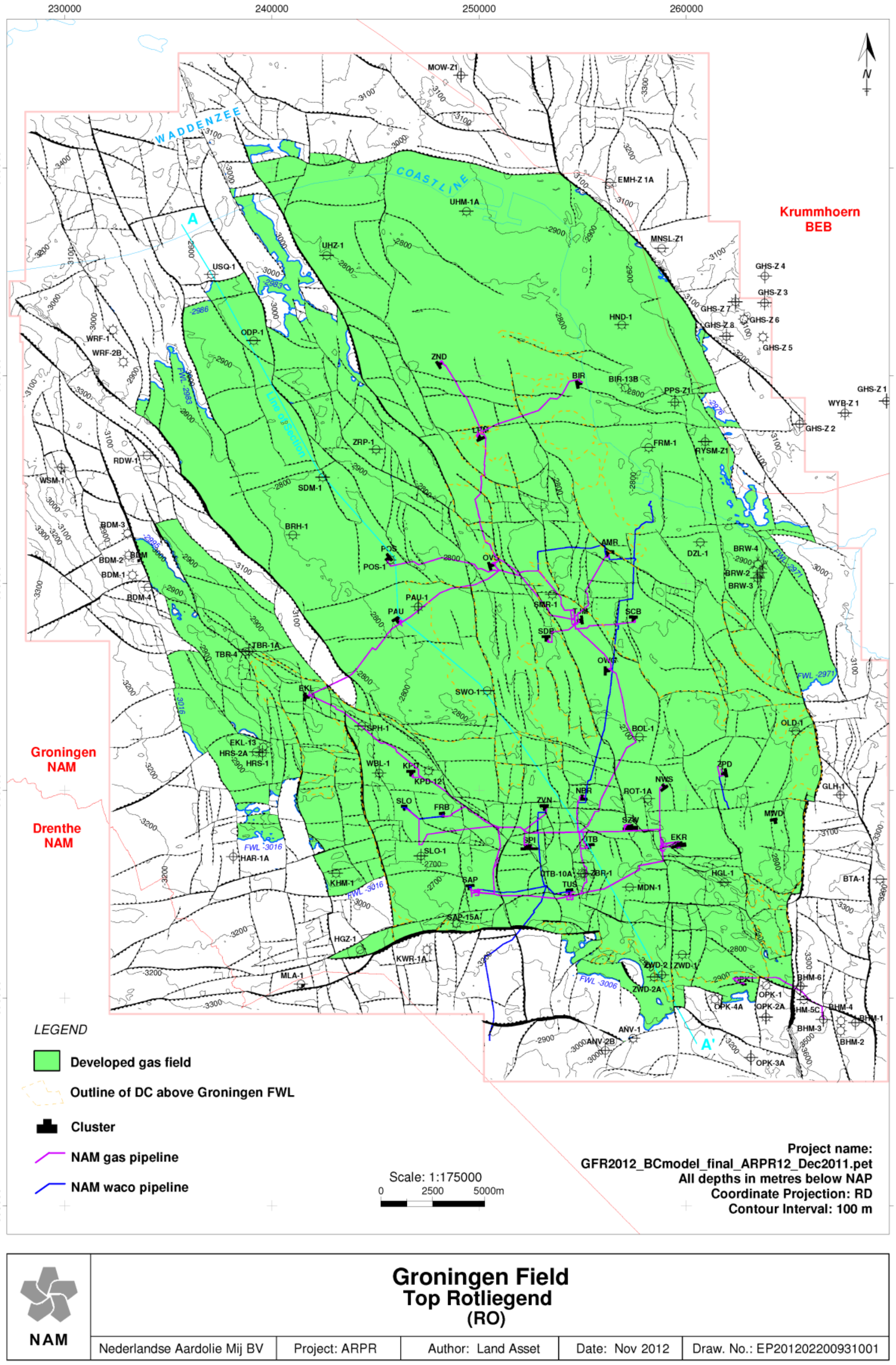

Figure A1.1: Groningen field Rotliegend top structure map.

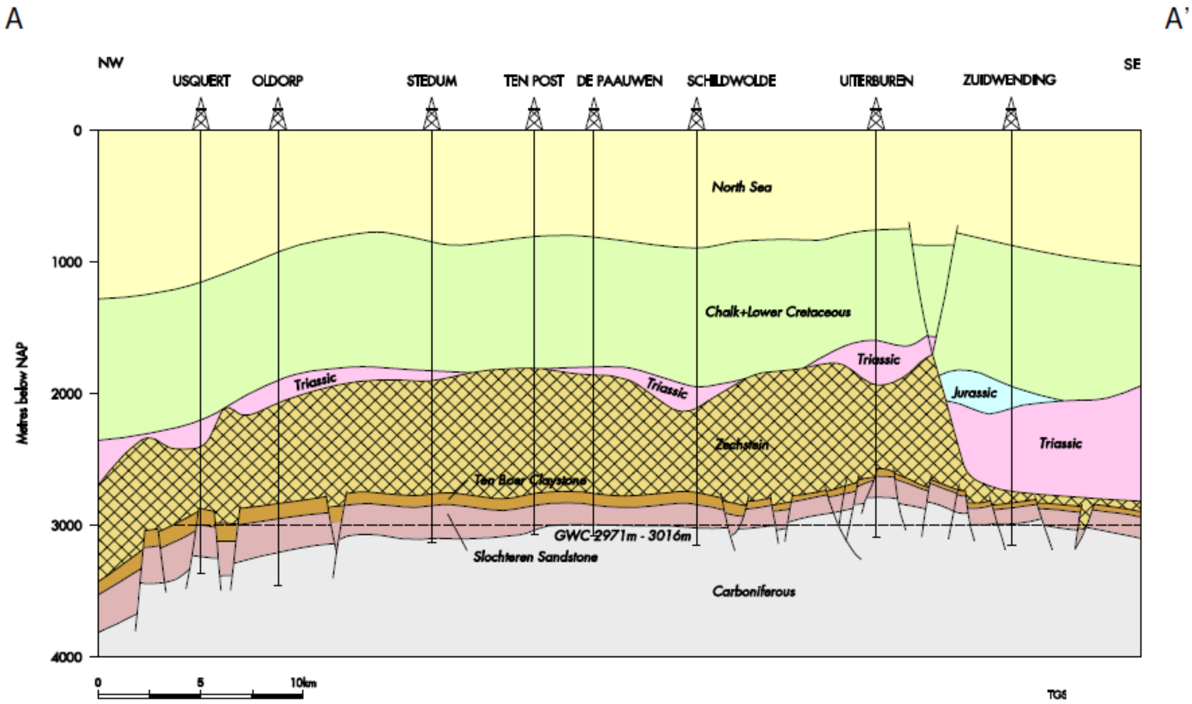

Figure A1.2: **Groningen field NW-SE cross-section (see Figure A1.1; approximately 7 times vertically exaggerated).**

Figure A1.3: **Field map showing the outline of the Groningen field with locations of production clusters, major pipelines, and locations of major towns and villages. Production from the Loppersum clusters has been constrained to 3 bcm/a.**

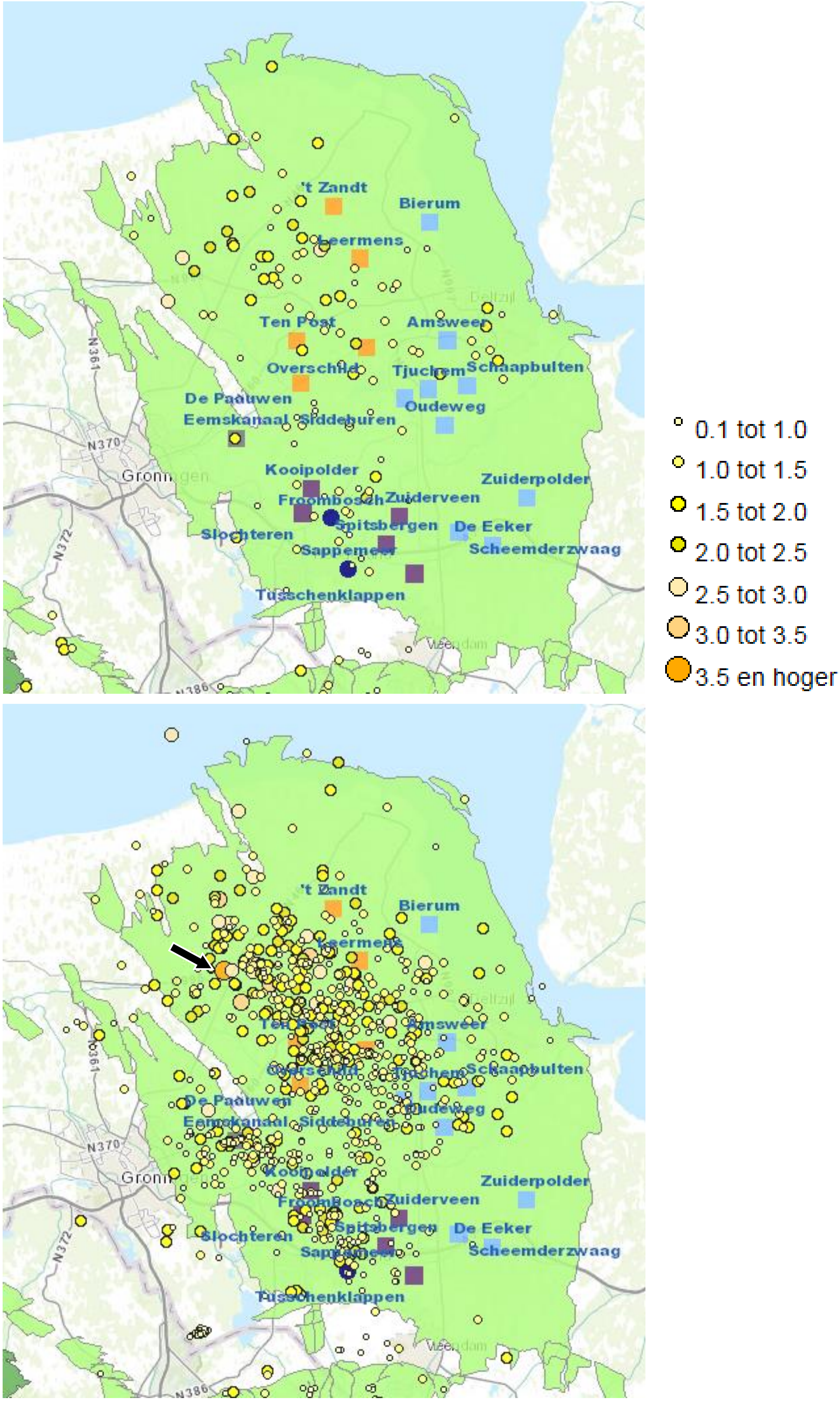

Figure A1.4: **Topographical map with outline of the Groningen field, locations of production clusters (ref. Figure A1.3) and epicentres of earthquakes measured between 1986 and 2000 (top) and measured from 2000 until mid-2015 (bottom). The colour and size of the circles indicating the epicentres correspond to the earthquake magnitude. The location of the 2012 Huizinge earthquake (M 3.6) is marked with an arrow in the lower map.**