Geological Analysis and Resource Assessment of selected Hydrocarbon systems

Deliverable

GARAH WP2:
3D Pilot Study - Conventionals

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GENERAL INTRODUCTION

This report summarises the work carried out to assess conventional hydrocarbon (HC) resources with a 3D basin and petroleum system model (BPSM) in a cross-border pilot study area as part of the Geo-ERA GARAH WP2: Assessment of North Sea Resources project. The assessment of conventional and unconventional resource in the whole North Sea area is made with thin eth GARAH project through the GARAH Deliveries 2.1 2.2. and 2.3. For this regional assessment, the results of the pilot study area provide insights and much better constrains on the Geological development.

In close cooperation the GARAH and 3DGEO-EU project's participants delineated the area of interest (AOI) and the stratigraphic framework for the 3D basin and petroleum system modelling study using the PetroMod software (v2019). The AOI comprises the cross-border area of the Danish, German, and Dutch Central Graben in the central North Sea. This area has been selected based on the geological, stratigraphical and geophysical data compilation, showing reasonable cross-border coverages as well as several potential and proven petroleum source rocks.

The construction of a single model of the pilot study area will in a comparable uniform way highlight the different interpretation and stratigraphic concepts of each country.

The 3D basin and petroleum systems model of the pilot study area allows for a comprehensive understanding of the petroleum systems in the area and enables the calculation of generated petroleum amounts and can be used for calculating and comparing various output parameters in the cross border area, e.g. maturity of source rocks, transformation ratio and migration and trapping of hydrocarbons.

The unconventional resources were assessed in a previous report (GARAH Deliverable report, 2.4 (Lutz et.al. (2021)). Conventional petroleum resources of the most important source rocks, i.e. the Jurassic Posidonia Fm, Bryne Fm and Farsund Fm, in the North Sea Central Graben will be assessed in this report.

GARAH deliveries related to hydrocarbon assessment in the North Sea.

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1 RATIONALE AND AIMS

The overall aim of the GARAH WP2 project is to assess cross-border conventional and unconventional hydrocarbon resources in the North Sea, Europe's most prolific oil and natural gas basin. As part of this overall objective of the GARAH project, a regional 3D basin and petroleum system model (BPSM) covering the Danish, German, and Dutch Central Graben area was constructed estimating petroleum resources (Figure 1).

The 3D BPSM model is a pilot study to reconstruct the thermal history, maturity and petroleum generation of potential and proven source rocks. As a first step we modelled the unconventional resources, meaning the shale source rocks. This has been assessed in a previous report (GARAH Deliverable report, 2.4 (Lutz et.al. (2021)). The conventional resources were assessed here and are reported as part of delivery D2.5.

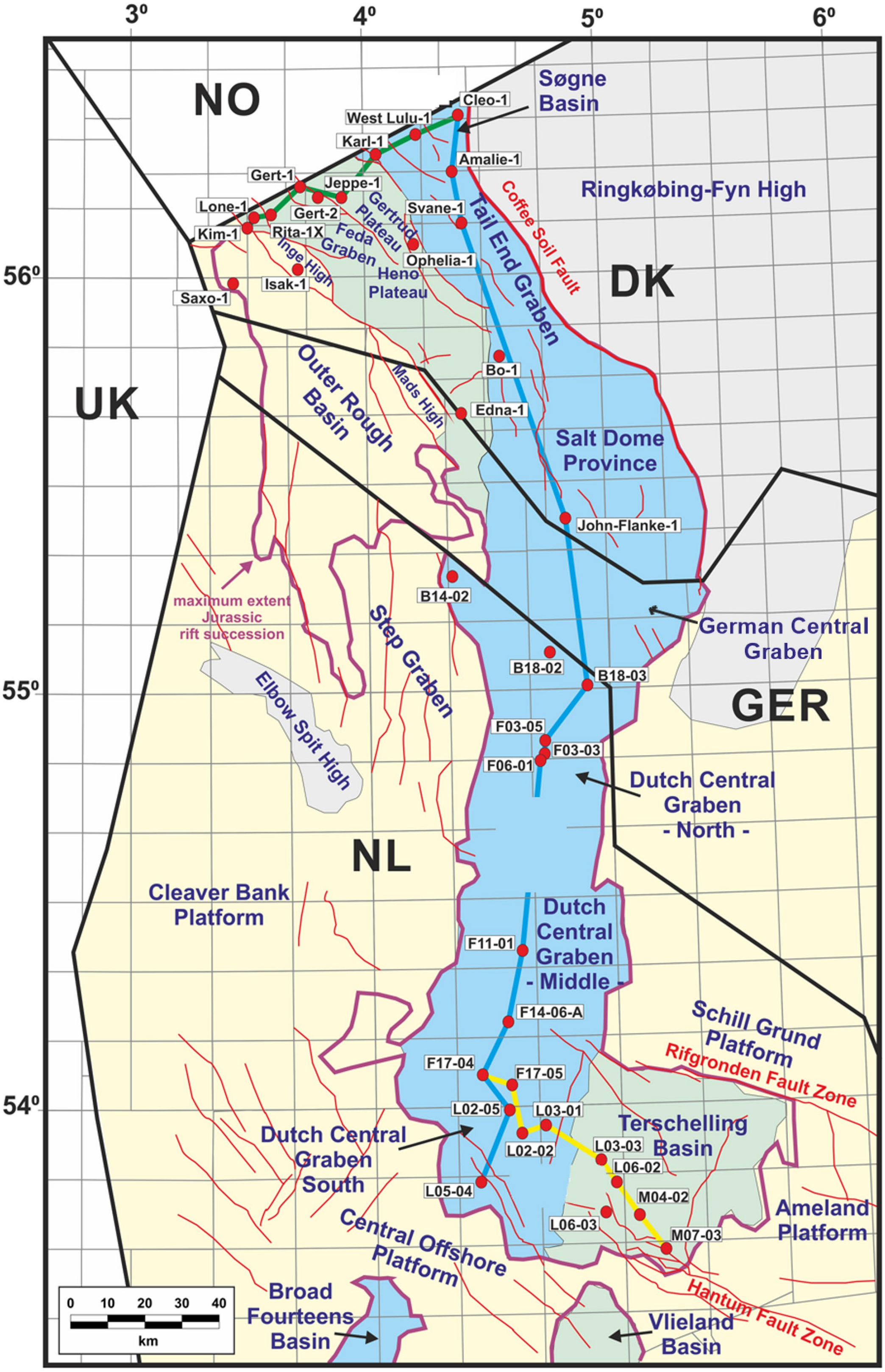

Figure 1: Geological structural elements of the study area. The Central Graben is the most prominent one, extending across the three countries (map modified from Verreussel et al., 2018)

2 CONSTRUCTING THE 3D PETROLEUM SYSTEM MODEL

2.1 Introduction

Basin and petroleum systems modelling combines seismic, geological and organic geochemical information to model the regional structural and thermal basin evolution. Based on a conceptual model, which includes all available information about the geological evolution of the study area such as petrophysical and organic geochemical data, a discretised numerical model is developed. Discretisation is performed by defining vertical grid lines and horizontal event lines. For each cell, numerical input data include thickness, age at upper and lower boundary, lithological properties and heat flow. For each source rock layer, input data such as total organic carbon (TOC) content, Hydrogen Index (HI) value and a kinetic data set for petroleum generation are further required (e.g. Schovsbo et al., 2020; Ponsaing et al, 2020; Lutz et al., 2004). The model provides information on timing, quantifies petroleum generation and migration and directs focus towards the parameters that affect simulation results the most (Peters et al., 2012). The 3D conceptual model is a deterministic forward model, which reconstructs the burial history and all related processes from time of deposition towards present day, e.g. sedimentation, erosion, compaction, radiogenic heat production, petroleum generation, migration and accumulation. Details on the theoretical and numerical background is given in Hantschel and Kauerauf (2009).

The 3D BPSM pilot study utilizes structural and stratigraphic subsurface models, which have been developed and improved within GeoERA 3DGEO-EU project (see 3DGEO-EU Deliverable report, 3.5 (Thöle et.al. (2020) and 3DGEO-EU Deliverable report, 3.6 (Thöle et.al. (2021). Relevant parameter layers for petroleum system modelling and source rock formations in the pilot study area, have been compiled and provided by the project partners. During construction of the 3D BPSM these layers have been combined, aggregated and incorporated.

A subset of these layers has been provided to the Information Platform of GeoERA.

2.2 Area of Interest

In close cooperation the GARAH and 3DGEO-EU project's participants delineated the area of interest and the stratigraphic framework (see GARAH Appraisal Report, 2.1 and Thöle at al., 2019) for the 3D basin and petroleum system modelling study (Figure 2). This area comprises the cross-border area of the Danish, German, and Dutch Central Graben in the central North Sea. This area has been selected based on the geological, stratigraphical and geophysical data compilation, showing reasonable cross-border coverages as well as several potential petroleum source rocks.

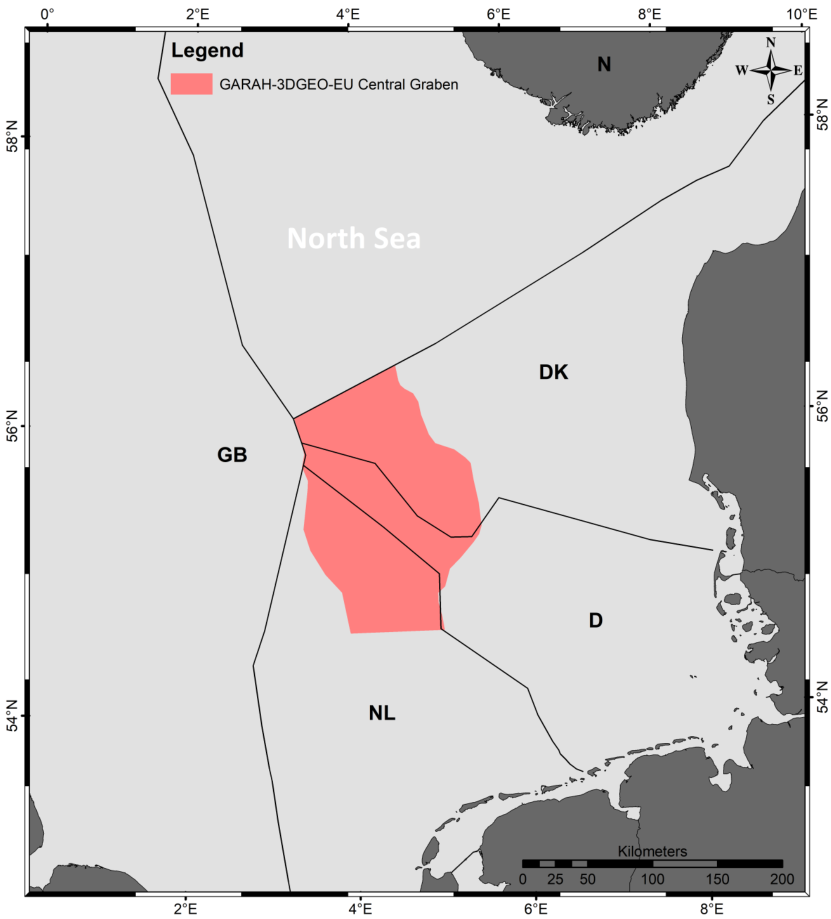

Figure 2 Location map of the central North Sea with outlines of the maritime borders. The 3D pilot study area is shown in red. It comprises the "Entenschnabel" in the German sector and adjacent Dutch and Danish offshore areas.

2.3 Stratigraphic Framework

Nine key horizons have been selected for building the stratigraphic framework of the 3D basin model in the central North Sea (Figure 3). These are:

0. Sea floor
1. MMU – Mid Miocene Unconformity
2. Near base Tertiary
3. Base Upper Cretaceous
4. Near base Lower Cretaceous
5. Posidonia Shale / Toarcian
6. Near Base Lower Jurassic
7. Near base Middle Triassic
8. Top Zechstein
9. Base Zechstein

For building the key horizon grids a workflow has been agreed upon by the project partners. Each horizon and its corresponding grid or point data in time domain, whichever is available, is merged to a time grid covering the pilot study area. These are cross-checked and corrected for obvious geological inconsistencies (e.g. such as cross-cutting layers). These time grids are then depth converted using the TNO procedure and algorithms for depth conversion (Doomenbal et al., 2019; Pluymaekers et al. 2017). Resolution of the grids is 250 m x 250 m and coordinates are given in UTM 31 N (WGS 84). More details on the 3D model can be found in GARAH Deliverable report, 2.4 (Lutz et.al., 2021).

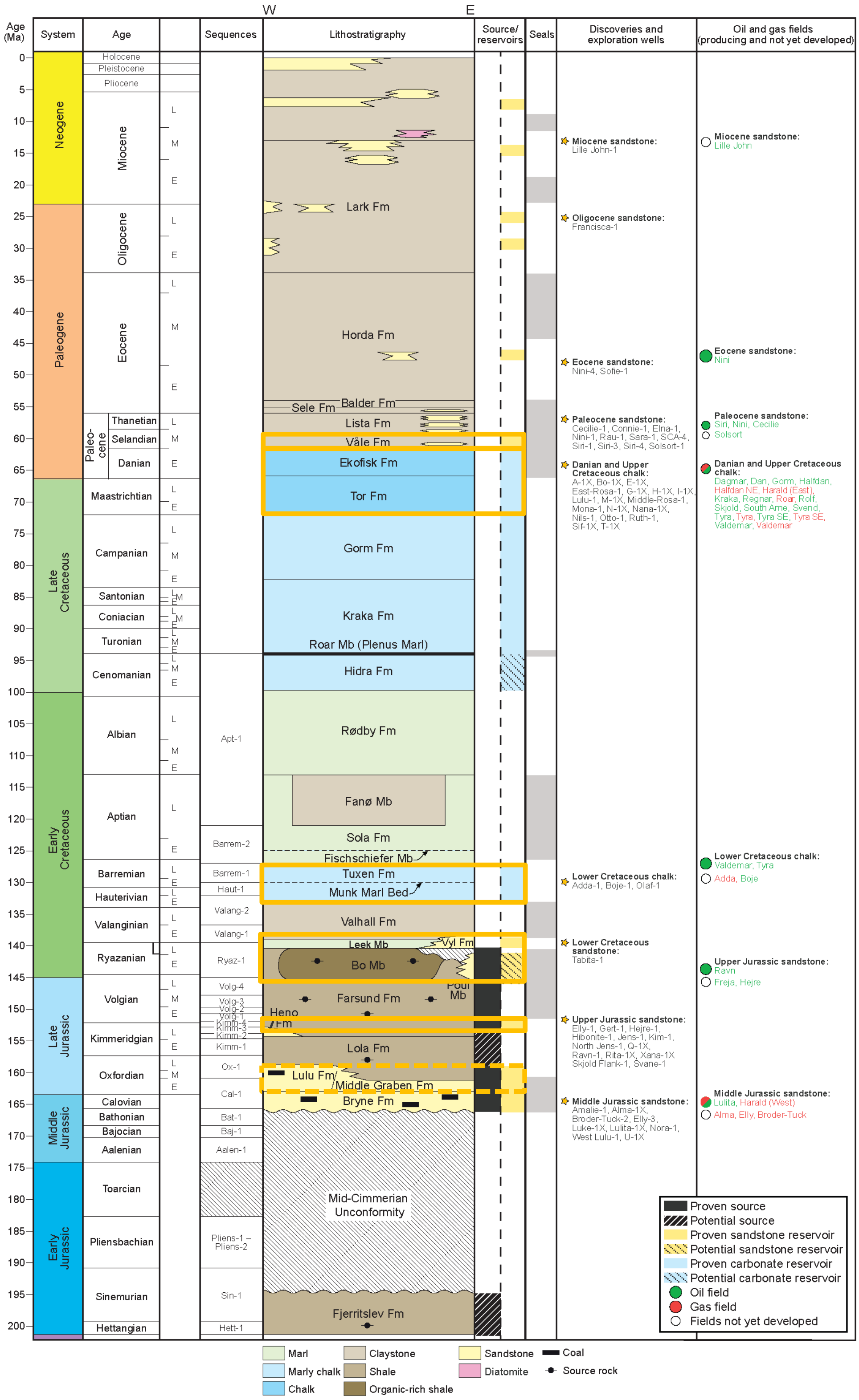

Figure 3. Stratigraphic framework after Schovsbo et al., 2020 with lithostratigraphy, Oil and Gas fields and discoveries, and potential Reservoir (orange rectangles) which were used for construction of the 3D basin model.

2.4 Methods and data base

3D petroleum system modelling was carried out with the software PetroMod 2019.1. Based on identification of key potential source rock intervals and reservoir formations, the combined 3D model was populated with the source and reservoir rocks identified within the project as possible target for accumulations of hydrocarbons. Furthermore, all layers received petro physical properties and for the source rocks, reliable and consistent organic-geochemical properties. Events of deposition, non-deposition and erosion were defined, and the basin evolution was reconstructed.

A set of attributes and parameters have been defined, which are necessary for building the model:

1. Present-day input
    - Absolute ages of horizons
    - Lithology
    - Facies maps

2. Paleo Geometry
    - Erosion events
    - Erosion maps - Paleo thicknesses of eroded formations
    - Salt maps, initial salt thicknesses, salt activity during basin evolution

3. Boundary conditions
    - Sediment Water Interface Temperature (SWIT)
    - Heat flow data
    - Paleo water depths

4. Calibration data
    - Vitrinite reflectance data
    - T_{max}
    - Temperature

5. Source rocks and their properties
    - Upper Jurassic (Farsund Fm, Bo Member)
    - Middle Jurassic (Bryne Fm)
    - Lower Jurassic (Posidonia Shale Fm)

6. Reservoir intervals
    - Upper Cretaceous (Ekofisk & Tor Fms)
    - Lower Cretaceous (Tuxen & Sola Fms)
    - Upper Jurassic reservoir intervals (see Schematic Figures 3 and 6)

For the calculation of vitrinite reflectance from temperature histories, the EASY%Ro algorithm of Sweeney & Burnham (1990) is used. This calculation method follows a kinetic reaction scheme and is valid for calculated reflectance values between 0.3 and 4.5 % vitrinite reflectance (VR).

2.4.1 Time – Depth Conversion

The present-day stratigraphic and structural framework of the model from the base Zechstein to Present is provided by using structural depth maps with a resolution of 250 x 250 m cell size or a low-resolution-version of 500 x 500 m cell size to reduce calculation time. Depth conversion was done using a velocity model. The purpose of this velocity model is the time depth conversion of the seismic interpreted time-grids to depth (Doomenbal et al., 2019).

To optimize the 3D model to calculate reasonable conventional resources, experiences from a 3D detailed unpublished in-house PetroMod BPSM including detailed overburden maps (Rasmussen et al., 2005) was used as guidance for the work here.

Well information from 63 wells covering the study area were available and 48 of the wells had vitrinite data available for calibration (Figure 4).

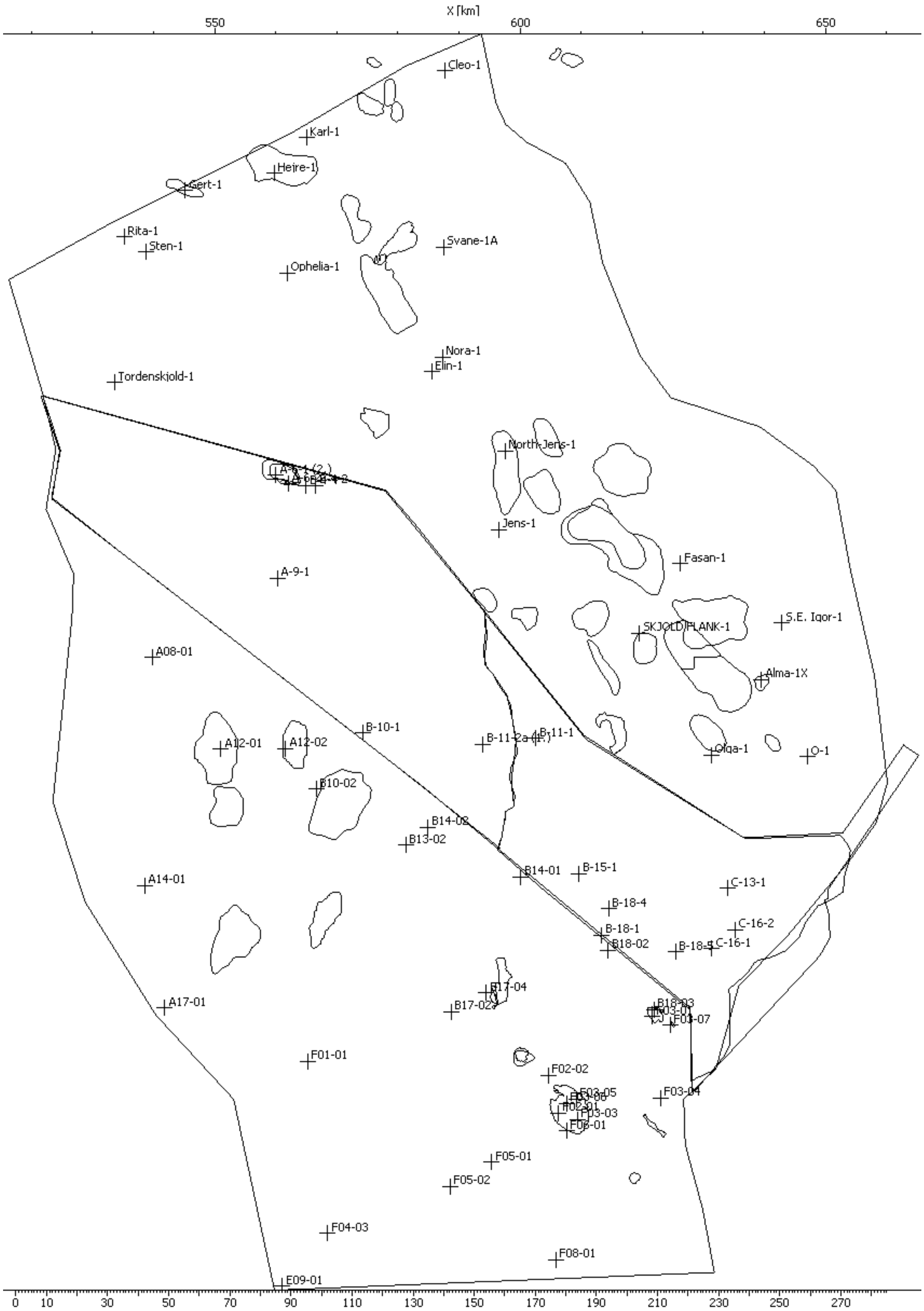

Figure 4: Location of wells integrated into the 3D BPSM. Crosses show well locations, small polygons indicate oil or gas fields, large outer polygon outline the study area. Notice that the oil and gas fields in Danish area has been updated with the latest field outlines (DEA field map, 2018; Schovsbo et al., 2020). The large polygon in the middle is the German Entenschnabel area.

2.5 Geological Model

The input model consists of ten model layers covering a time interval from the Zechstein to the present. A sedimentary basement of 2000 m thickness for the pre-Zechstein formations was added to extend the 3D model below the Upper Permian.

In this study, an initial thickness of 700 m is assumed for the Zechstein layer (Ten Veen et al. 2012) before halokinesis ultimately formed salt diapirs (Figure 5).

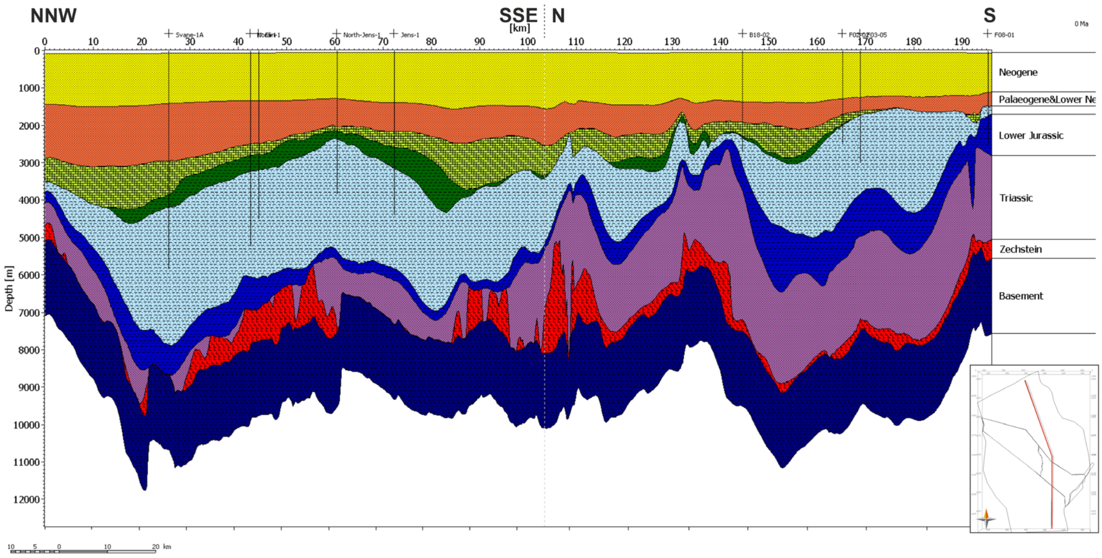

Figure 5: 2D cross section across the 3D model showing the sedimentary layers and the salt diapirs (red). Red line in inset map shows profile line.

Four erosional phases are included in the basin model: the Mid-Cimmerian (Mid-Jurassic), the Late Cimmerian (Early Cretaceous), the Subhercynian inversion (Late Cretaceous), and a final one during Mid Miocene time (Figure 6).

The domal uplift during the Mid Cimmmerian phase resulted in a widespread erosion in large parts of the study area. The intensity and amount of erosion varied in the area, depending on the structural elements (basin, high, platform). The erosion event began during the Bathonian (165 Ma) and ended in the Oxfordian (158 Ma). Layers that were affected by this erosional phase include Triassic and Lower to Middle Jurassic sediments. The Late Cimmerian erosion phase (from 122 Ma to 98.9 Ma) affected the Dutch and Danish North Sea area and eroded Upper Jurassic sediments.

	Age [Ma]	Horizon	-	Depth Map	Erosion Map	Layer
1	0.00	Horizon_0		Seafloor		
2						Neogene
3	11.20	MMU				
4						Erosion_17
5	15.97	Horizon_1		MMU_DE_NL_DK	MMU_30m	
6						Palaeogene&Lower Neogene
7	59.05	Palaeocene_RES		Palaeocene_RES_01		
8						Palaeocene_RES
9	61.60	Horizon_2		Base_Tertiary_DE_NL_DK		
10						Upper Cretaceous
11	83.50	Sub-Hercynian				
12						Erosion_65
13	98.90	Horizon_3		Upper_Cretaceous_DE_NL_DK	SubHercyn_plus_LateCimm_D	
14						Lower Cretaceous
15	122.00	Late-Cimmerian		Late-Cimmerian	Late_Cimm_Erosion_NL_DK_Non_Erosion_D	
16						Late-Cimmerian
17	142.00	Horizon_4		Base_Cretaceous_DE_NL_DK	Late_Cimm_Upper Jurassic_LCretDK_Erosion_NL_D_DK_142	
18						UppJura_VylPoulRES
19	143.18	Upper Jurassic		Upper Jurassic_02		
20						Upper Jurassic
21	157.69	UppJura_HenoRES		UppJura_HenoRES		
22						UppJura_HenoRES
23	158.00	Mid-Cimmerian				
24						Erosion_32
25	165.50	Horizon_5		Upper_Jurassic_DE_NL_DK	Lower_Middle_Jurassic_Erosion_MidCimm_NL_D_DK_165.5	
26						Lower Jurassic
27	201.30	Horizon_6		Base_Jurassic_DE_NL_DK	Triassic_Erosion_MidCimm_NL_D_DK_201.3	
28						Triassic
29	251.00	Horizon_7		Base_Lower_Triassic_no_diapir		
30						Zechstein
31	258.00	Horizon_8		Base_Zechstein_DE_NL_DK		
32						Basement
33	380.00	Horizon_18		Basement		

Figure 6: Stratigraphic succession of the 3D model and assigned ages to the individual sedimentation and erosion events. Light green rows indicate erosion. The Late Cimmerian event is characterized by deposition in Germany and erosion in Denmark and the Netherlands. Notice the position of the Upper Jurassic reservoir layers (i.e. Palaeocene_RES, UppJura_VylPoulRES and Upp_Jura_HenoRES.

A major Late Cretaceous inversion phase in the North Sea basin resulted in uplift and erosion of the sedimentary fill in different pulses and is called the Subhercynian erosional event. Partly, Upper Jurassic, Lower Cretaceous and Upper Cretaceous sediments were eroded in the central and north-western part of the study area. Here, erosion during the Late Cretaceous was active between 98.9–83.5 Ma. The final erosion during the Mid-Miocene with a duration of ~5 Ma (from 15.97 Ma to 11.2 Ma) is included with an erosion thickness of 30 m (Figure 6). Assigned lithology for each of the model layers is based on generalised well descriptions within the study area.

Paleo thickness values are estimated and based on Arfai and Lutz (2017) and seismic interpretation results covering basin and graben formations for the German North Sea. Eroded thicknesses for Denmark and the Netherlands were provided by GEUS and TNO, respectively.

The two most important source rocks of the North Sea are the Upper Jurassic Bo Member of the Farsund Fm and the Lower Jurassic Posidonia Shale Fm. The Bo Member is the main source rock for the oil fields in Denmark and likely extends partly into Germany. The Posidonia Shale Fm is an important oil source rock in the Netherlands and also extends into Germany. The Bryne Fm includes coals in the Middle Jurassic in Denmark only.

The Posidonia Shale source rock is characterised with an average TOC content of 5 wt% in Germany and a TOC map for the Netherlands with values ranging between 3.55 and 4.96 wt%, and an HI value of 500 mg HC/g TOC. The Farsund Fm (Bo Mb) source rock is defined with a TOC content of 5 wt% and an HI value of 400 mg HC/g TOC. The Bryne Fm coals has a TOC content of 70 wt% and an HI value of 300 mg HC/g TOC.

Hydrocarbon generation of the Posidonia Shale Fm and Farsund Fm (Bo Mb) was calculated using the kinetic data set of Pepper & Corvi (1995) type TII(B) and the Bryne Fm was assigned the reaction kinetic Pepper & Corvi (1995) type TIIIH(DE). A 3D view of the model is shown in Figure 7.

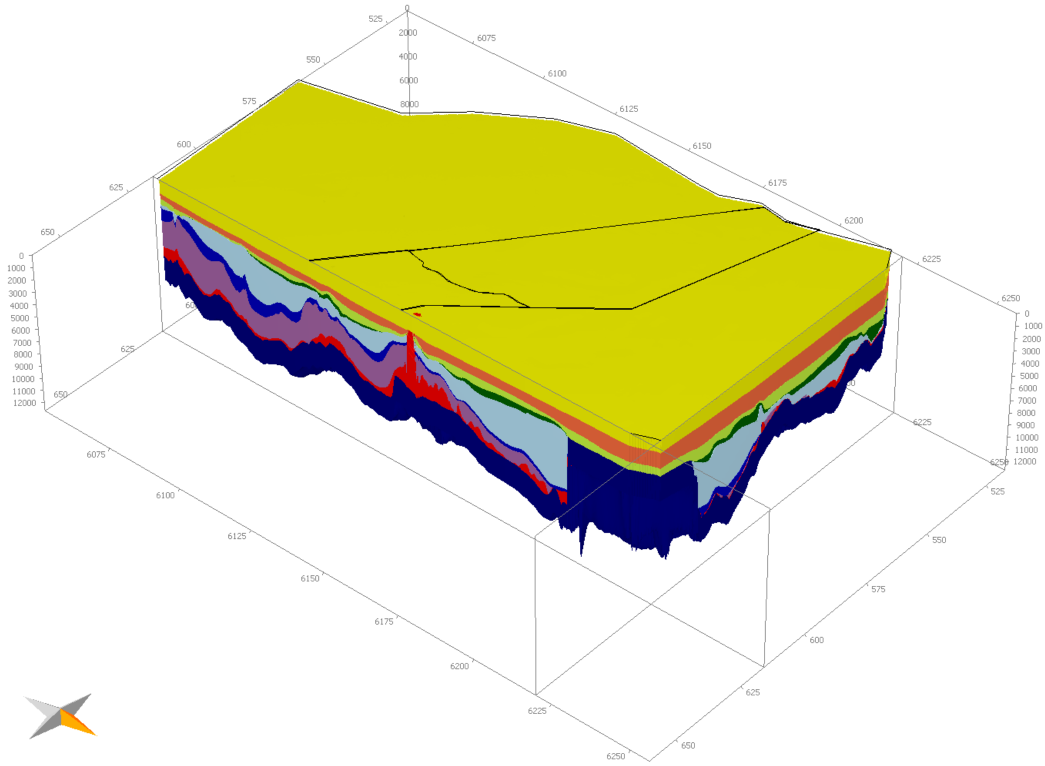

Figure 7: View from the NE into the 3D model. The eastern and northern sides are cut off for a better view into the model. Red layer is Zechstein salt and light blue layer is Upper-Middle Jurassic.

2.6 Boundary conditions

2.6.1 Palaeo Water Depth (PWD)

The paleo water depths *(*PWD) curve used in the model was constructed based on PWD trends of adjacent areas in the southern Dutch Central Graben (Verweij et al. 2009; Abdul Fattah et al. 2012a, b; Arfai & Lutz 2017; Rasmussen et al., 2005). The paleo water depths were allowed to vary in time but were kept constant over the entire area at a certain time. The PWD is less than 100 m with shallowing during erosion phases and deepening in-between.

2.6.2 Sediment Water Interface Temperature (SWIT)

The paleo surface temperature at the sediment water interface was calculated with an integrated software tool that takes into account the paleo water depth and the paleo latitude of the study area (Wygrala 1989).

2.6.3 Basal Heat Flow

The main heat flow trend is based on the McKenzie model for a passive margin (North Sea basin) and is also adopted from studies covering the adjacent areas (Verweij et al. 2009; Abdul Fattah et al. 2012a, b; Arfai & Lutz 2017). One heat flow trend was assigned to the Step Graben System and a different one to the Central Graben.

During the Early Triassic (251 Ma) a peak (63 mW/m²) is included in the heat flow trend attributed to first post-orogenic (Variscan orogeny) rifting phases. This rifting stage is characterised by the beginning of graben formation and subsequent Triassic–Middle Jurassic tectonic subsidence and thickening of sediments within the Central Graben area. A second increase (85 mW/m²) during the Late Jurassic at 158 Ma represents the main heat flow event in the Central Graben area (Figure 8). This major extensional phase during the Late Jurassic formed the present-day Central Graben geometry. Subsequent Cretaceous and Cenozoic subsidence was largely controlled by a phase of post-rift thermal subsidence. The compressional stress regime resulted in several phases of basin inversion during the Late Cretaceous. However, this event had only a minor impact on the heat flow history and we assigned a heat flow value of 65 mW/m² for this time period. The present-day heat flow was calibrated based on temperature and vitrinite reflectance data.

The heat flow trend for the Step Graben System is the same as for the Central Graben until the Mid Jurassic. The Late Jurassic rifting of the Central Graben is omitted in the Step Graben heat flow trend (Figure 8). The values decrease constantly from the Mid Jurassic to the present-day value of 52 mW/m².

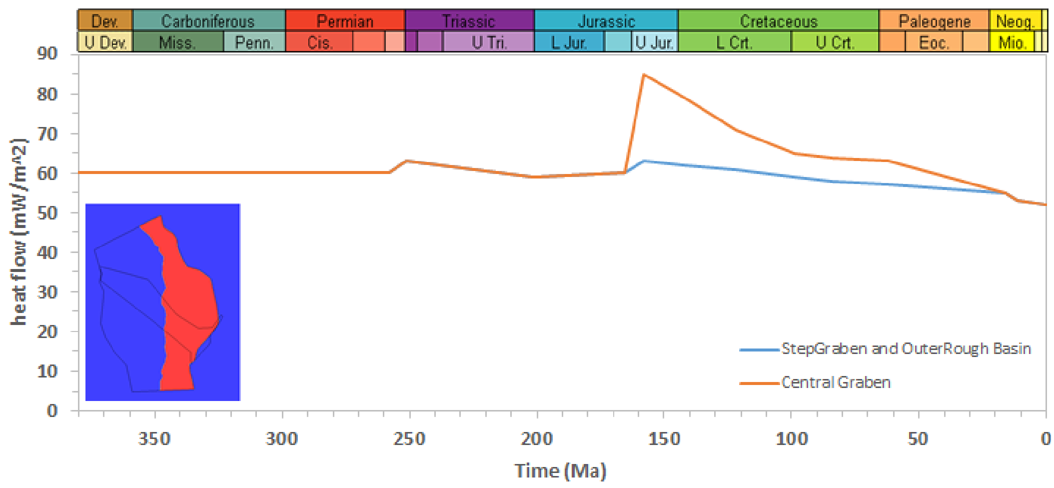

Figure 8: Heat flow trends for the pilot study area. Blue is the heat flow trend assigned to the area outside the Central Graben and red is the heat flow trend within the Central Graben. Inset shows the heat flow trend assignment in map view.

An alternative heat flow model was also calculated to test the influence of different heat flow scenarios on the simulation results (see GARAH Deliverable report, 2.4 (Lutz et.al. (2021)) for details). However, a slightly better fit between measured and calculated vitrinite reflectance values was achieved with the default heat flow model (Figure 8). The main difference between the models was the timing of maximum temperature, where the default model assumed a heat flow peak in the Central Graben area during the Jurassic and the alternative model assumes highest temperatures during the Cenozoic. Thus, the default heat flow was used for assessment of the conversational resources.

3 3D BPSM SIMULATIONS

3.1 The conventional petroleum systems

In the unconventional petroleum systems, the aim was to assess the generated hydrocarbons that have not yet been expelled, but the oil and/or gas that remains in the source rock (i.e. source rock is the reservoir). The amounts that are retained are either adsorbed or retained as free gas in the source rock (see GARAH Deliverable report, 2.4 (Lutz et.al. (2021)) for details and results).

For conventional petroleum systems, the aim is to assess the hydrocarbons generated, expelled, migrated and accumulated in suitable structures. In this petroleum system, oil or gas are expelled from the source rock and migrated through a carrier and accumulated in a reservoir rock. Thus, the generated amounts and the amounts lost through the sides of the model and through the top of the model due to seal leakage during evolution are also important.

In this study, the PetroMod multilayer flow path (Hybrid: Darcy + Flow path) was used to access migration to potential reservoir accumulations. Flow path is a map-based migration method, where hydrocarbons migrate buoyancy driven to the top of the structure, with the migration occurring instantaneous. When using Flow path migration, 100% upward expulsion of hydrocarbons is assumed. In multilayer flow path several carrier beds can be used together simultaneously. Migration from one layer to the other works via top seal leakage. Flow path layers or carriers have to be pre-defined.

Although this is a very simplistic way of migration modelling, it normally gives good regional results, explaining most of the observations.

In order to simplify the modelling process and communication of the results, the migration models of the Upper Jurassic Farsund source and the Middle Jurassic Bryne source were kept separate. This is geologically justified, as both systems are generally regarded as separated, even though a certain amount of mixture of the two systems must be expected (see Section 2.5)

Beside this, the implementation of migration in the areas of the model boundaries can have implication on the final drainage system and accumulations in fields near there areas. The model allows migration out of the model sides except towards Ringkøbing-Fyn-High (RFH; Fig. 1) in the eastern part of the model where impermeable salt facies prevent migration towards east.

4 3D BPSM RESULTS

4.1 Maturation, source rocks and generation

The model presented here is the first public 3D basin and petroleum system combined model across the Danish, German and Dutch Central Graben area. The vitrinite reflectance overlay on the Upper and Lower Jurassic layer shows the complex varying cross-border present day thermal maturity distribution (Figure 9 and Figure 10), and the maturity distribution highlights the different structural settings and basin evolution across and on both sides of Central Graben.

The Upper Jurassic (Figure 9) is in the oil window for the largest part of the Danish Central Graben area. In contrast, in the German part of the study area in general only the early oil window is reached and only in few, fragmented, small patches, especially outside the Central Graben area sensu stricto, in the Outer Rough Basin (see also Figure 1 for structural elements). In the Dutch North Sea the Upper Jurassic is also only marginally mature, i.e. partially in the early oil window.

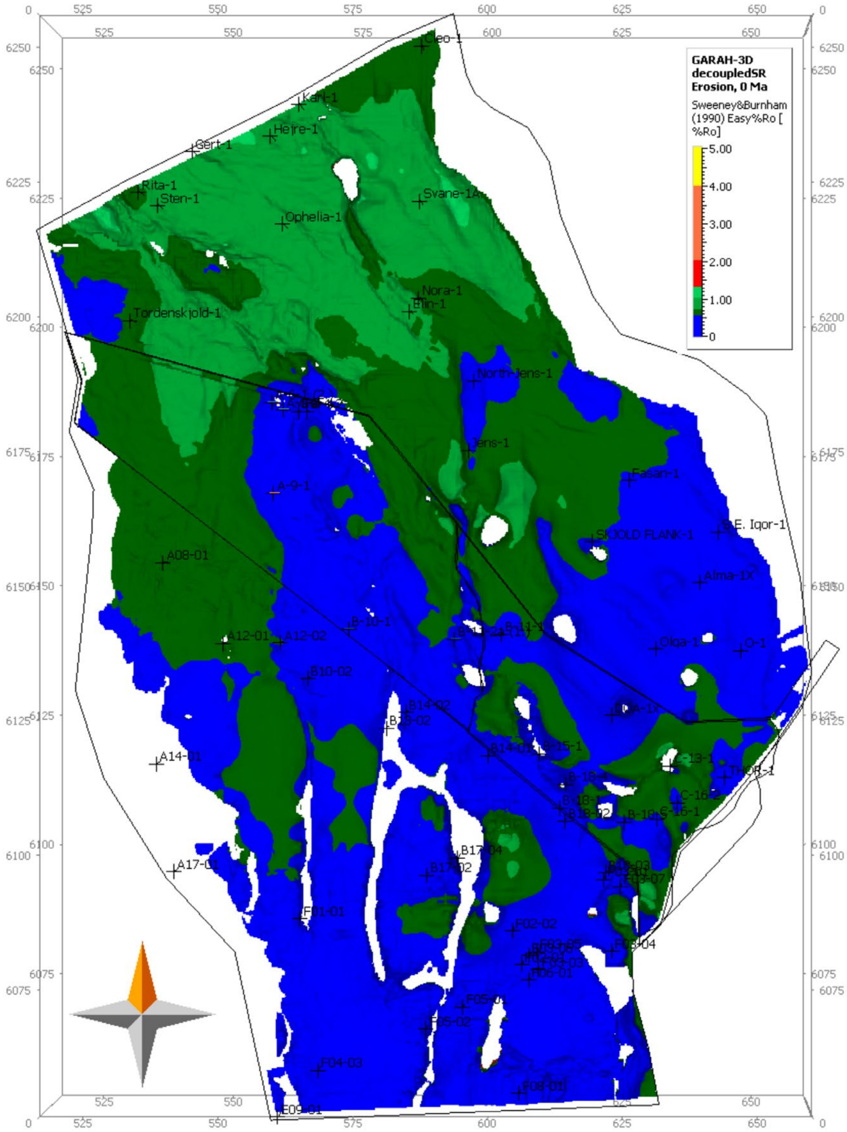

Figure 9: Calculated vitrinite reflectance at the top of the Mesozoic pre-Cretaceous sediments, i.e. mostly top Upper Jurassic, where missing top Lower Jurassic or Triassic. Blue=immature, green=oil window.

The maturity of the Lower Jurassic is significantly higher than the Upper Jurassic (Figure 10). Again, highest maturities are reached in the Danish North Sea, where large parts are in the gas window or are already overmature. Towards the south and into the German North Sea, maturity decreases, and oil window maturities are reached. Into the Dutch North Sea, maturities increase, and the gas window is reached.

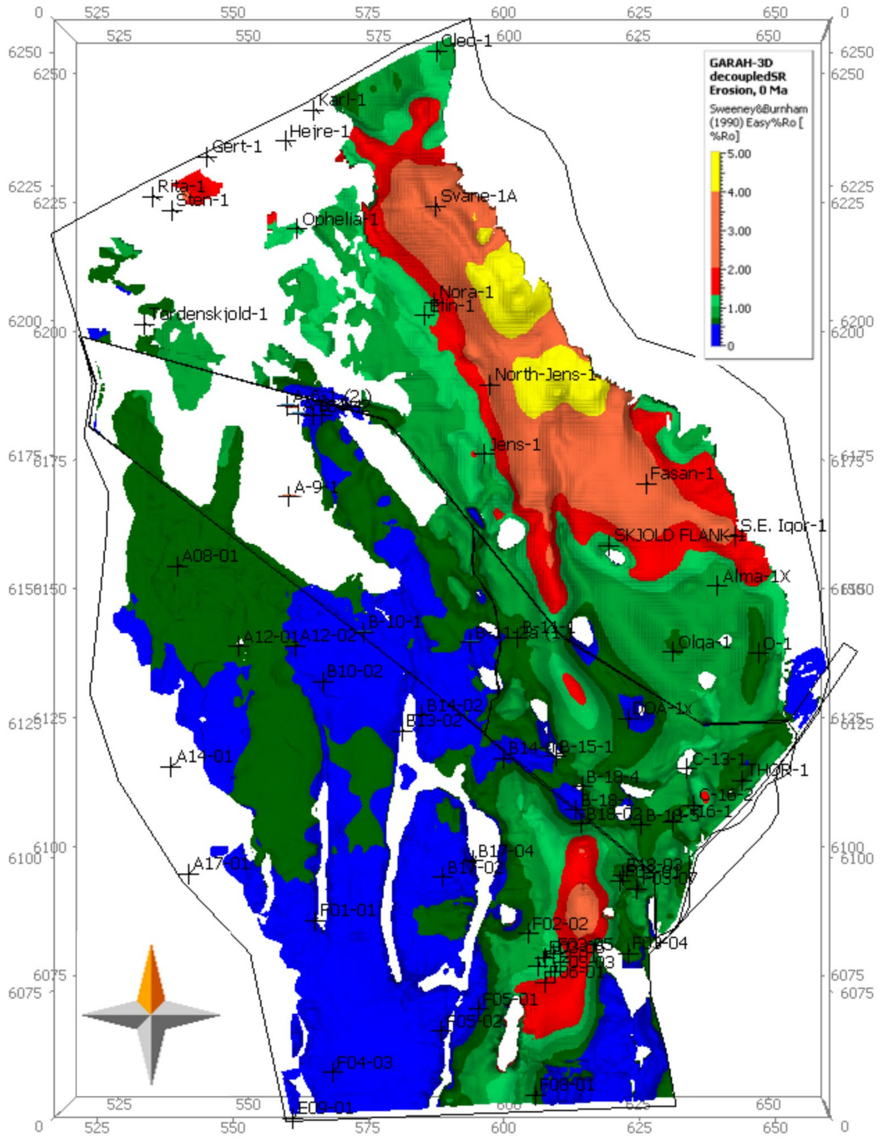

Figure 10: Calculated vitrinite reflectance at the top of the Mesozoic pre-Upper Jurassic sediments, i.e. mostly top Lower Jurassic, where missing top Triassic. Blue=immature, green=oil window, red=gas window, yellow=overmature.

Figure 11 shows the extent of the four source rocks in the 3D model study area.

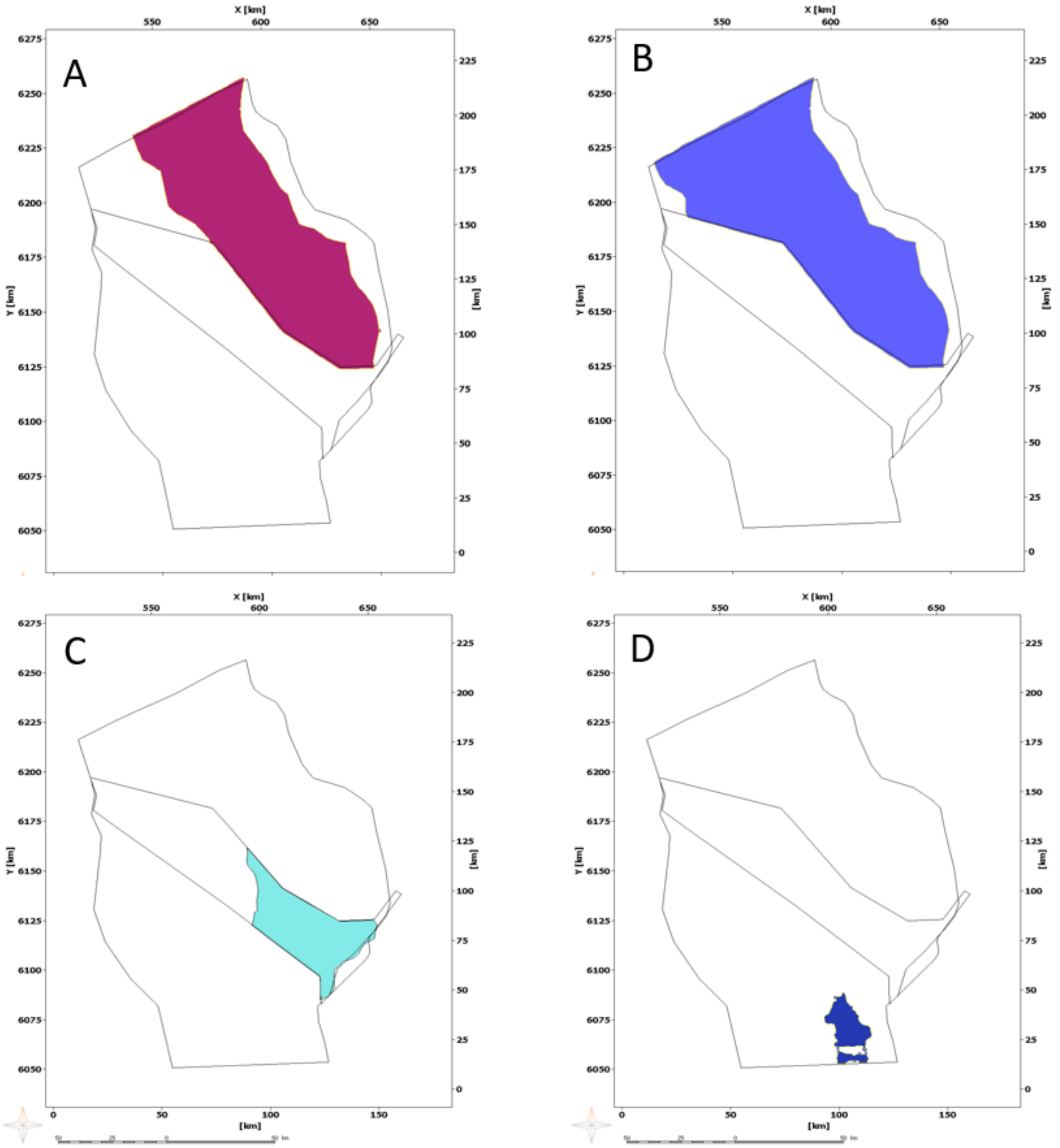

Figure 11: Distribution of the Upper Jurassic Bo Mb (A) and Middle Jurassic Bryne (B) source rocks in the Danish Central Graben, the Posidonia source rocks (C) in the German Central Graben and the Dutch Posidonia source rock (D) only present in the southern Dutch Central Graben.

The different source rock distribution and their level of maturation resulted in different amounts of generated petroleum across the 3D model (Figure 12). Figure 12 and Figure 13 shows the transformation ratio (TR) and how most of the generated hydrocarbons from the Upper Jurassic and the Middle Jurassic Bryne source rocks are located in the Danish Central Graben (DCG).

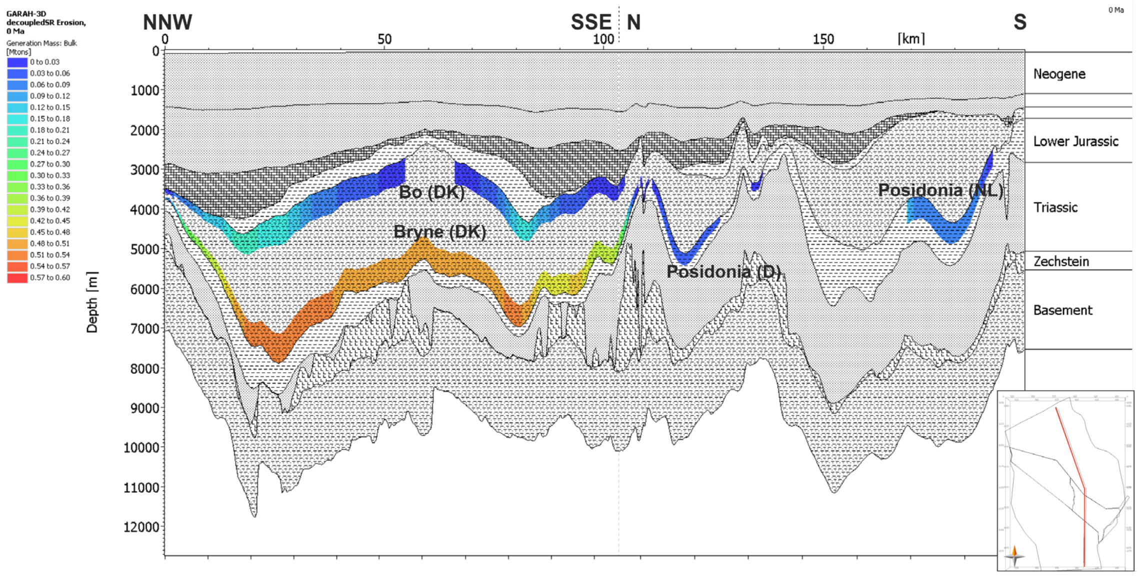

Figure 12: 2D cross section across the 3D model showing the generated mass of petroleum for the source rocks. Red line in inset shows profile line and it is the same as in Figure 5. Notice that the Upper Jurassic Bo Mb source rock did not generate hydrocarbons in the Germany area, due to insufficient maturity. The TR values are shown for each cell and do not represent the true source rock thickness.

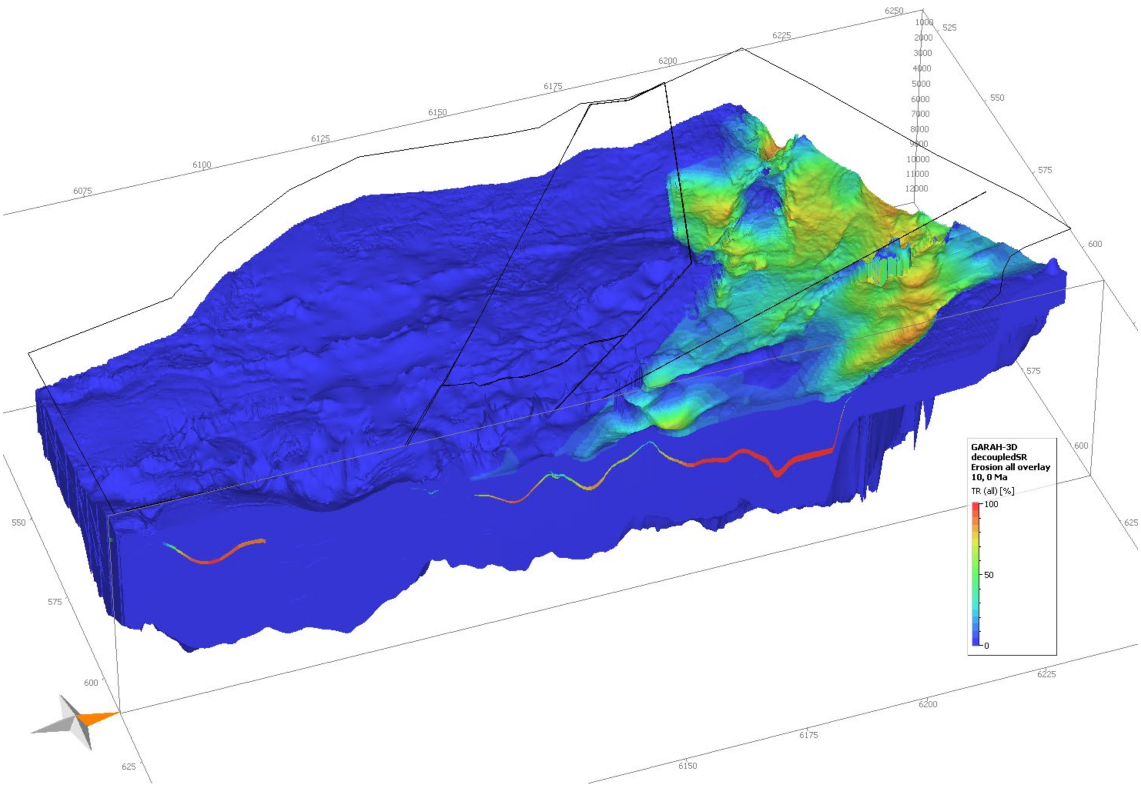

Figure 13: Transformation ratio (TR) at the top of the Upper Jurassic layer. Coloured line at the side are deeper lying source rocks.

4.2 Previous assessments and modelling in the Danish Central Graben

The 3D BPSM results are general in accordance with previous modelling in the Danish Central Graben (DCG). The source rock quality was reviewed in Schovsbo et al. (2020) while the thermal maturity was evaluated through 1D basin modelling (Ponsaing et al, 2020), with focus on the Upper Farsund Formation source-rock richness.

- The upper part of the Farsund Formation (the Volg-3–Ryaz-1 sequences) is immature in the southern part of the Salt Dome Province, and late oil mature in and near the Tail End Graben and in the Søgne Basin (Figure 9).
- The lower part of the Farsund Formation is immature in local areas, yet post-mature in the Tail End Graben and in the Rosa Basin within the Salt Dome Province.

- The Lower Jurassic and the Middle Jurassic Bryne, Lulu and Middle Graben Formations are gas-prone in most of the Danish Central Graben (DCG) (Figure 10).

The upper part of the Upper Jurassic–lowermost Cretaceous source rock succession (Volg-3–Ryaz-1 sequences) is more oil-prone than the underlying sequences (Ponsaing et al., 2020). Results show that all kitchen areas are in the main oil window, and that oil mainly has been expelled from the three uppermost sequences (Volg-3 to Ryaz-1; see Figure 3). The potential for oil generation is generally very limited in the lowest part of the succession (sequences Kimm-1 to Kimm-3; see Figure 3), even though scattered, more oil/gas prone intervals may generate oil. The variety in oil types, is believed to be a result of different organofacies present in varying proportions within the sequences (Ponsaing et al., 2020). The 1D modelling showed that the kinetic model and the averaged values of TOC, HI and the thickness are important for generation and expulsion. Thus, selection of kinetic model, and the values of TOC, HI and thickness of the sequence are important for predicting generation and expulsion. Sensitivity runs showed that by increasing the values of TOC, HI and thickness of a sequence to more than 3 wt%, 250 mg HC/g TOC and 20 m, respectively, expulsion of hydrocarbons could occur, even from the lower part of the succession. Thus, the lack of expelled gas from lower parts of the Upper Farsund source rock sequence could be a result of not selecting the most representative kinetic model for the source rock sequences, and can have impact om the distribution of accumulated HCs and the heterogeneity in the oil types accumulated within the fields, as each organofacies presumable will generate different types of oils.

In accordance with previous modelling the uppermost source rock interval (the Ryaz-1 sequence), illustrated by four representative deep wells in the Gertrud Graben, Søgne Basin and Tail End Graben, entered the oil window in the late Palaeogene, reaching the main oil window within the last c. 5–10 Ma.

The depth of the oil window, as defined by a vitrinite reflectance of 0.6% Ro, ranges between 2200 and 4500 m in the DCG, where much of this variation in depth is a consequence of heat flow differences and especially the thickness of the Palaeogene to Cretaceous Chalk and Cromer Knoll Groups, where a thick Chalk Group offsets the oil window to deeper levels, which likely can be attributed to the thermal properties of the highly thermally conductive chalk compared to the underlying less thermally conductive clays (Ponsaing et al, 2020).

4.3 Testing sensitivity of critical model parameters

In contrast to probabilistic simulations, where 10,000-100,000 calculations can be easily realized, the number of possible simulation runs for full 3D models are limited due to the long simulation times. Nevertheless, the impact of the most important parameters on the results can be assessed by simulating scenarios with varying values for these parameters.

In order to save computation time for the parameter tests we sampled the models in x-y direction two-fold and reduced the number of sublayers in the Lower Jurassic to Upper Cretaceous layers.

To further test the sensitivity of the 3D model the following test were conducted:

- Impact on model results of using modes sample in various x-y- direction. From the unconventional study we know that running a two-fold version only reduced the total amount of retained petroleum by 3 %. From the conventional study below, we can show that running a two-fold version reduces the total amounts by up to 10-15 %, depending on model scenario.
- Various model runs show that changing reservoir and seal properties can have large impacts on volumes and location of individual HC accumulations. Figure 15 shows the distributions of HC accumulations based on the original unconventional model. By changing the local reservoir properties, which we normally do not know in detail and thus is

difficult to include in a regional model, it is possible to better match the known accumulations (compare with Figures 15 and 16).

- Furthermore, changing the lithology in and around the source rocks from e.g. siltstones dominated to sandstones facies will allow for more expulsion of petroleum out of the source rock allowing it to act as a carrier of generated HCs and more effective migration towards possible accumulations (Figure 14). From the unconventional study we know that the accumulated amount of petroleum in the source rock can be reduced by around 17 %. From the conventional study below, we can show that the accumulated amount of petroleum in the accumulations can be reduced by up to 20-25 %, depending on model scenario.
- The Danish Central Graben is an overpressured basin. High fluid pressures > 70 MPa and high temperatures > 150°C are expected to occur deeper than 3.8 km except for the Feda and Gertrud Grabens where it is expected to be effective from around 4.7 km depth due to general lower temperatures here (Schovsbo et al., 2020). To test the effect of the of overpressure buildup in the Cenozoic section various model runs tested the impact on the modelling results and HCs accumulations (Figure 17). By changing the original sandy lithology used in the unconventional study for the Neogene and Palaeogene&Lower Noegene sequences to tighter shaly lithologies pressure built-up in the upper part of the Cenozoic section was created (Figure 18). However, the scenario runs also show that variation in fluid pressure within the present study area is difficult to mimic due to the regional simplified 3D model. To mimic fluid and overpressure the 3D BPSM model has to be further sub-divided to control pressure development in the Cenozoic section, the Chalk Group, the Lower Cretaceous (i.e. the Cromer Knoll Group) and the Upper Jurassic sequences. Furthermore, the standard PetroMod lithofacies library has to be adapted to include information on depositional distribution of tighter lithofacies, than existing standard lithofacies.

Notice that most of the Dutch field outlines in the A and B blocks represent shallow gas fields which have been described as having a biogenic source. Biogenic generation of hydrocarbons was not included in the 3D model, these fields are therefore not reproduceable and were excluded from the result discussions (see also Section 5.1.3).

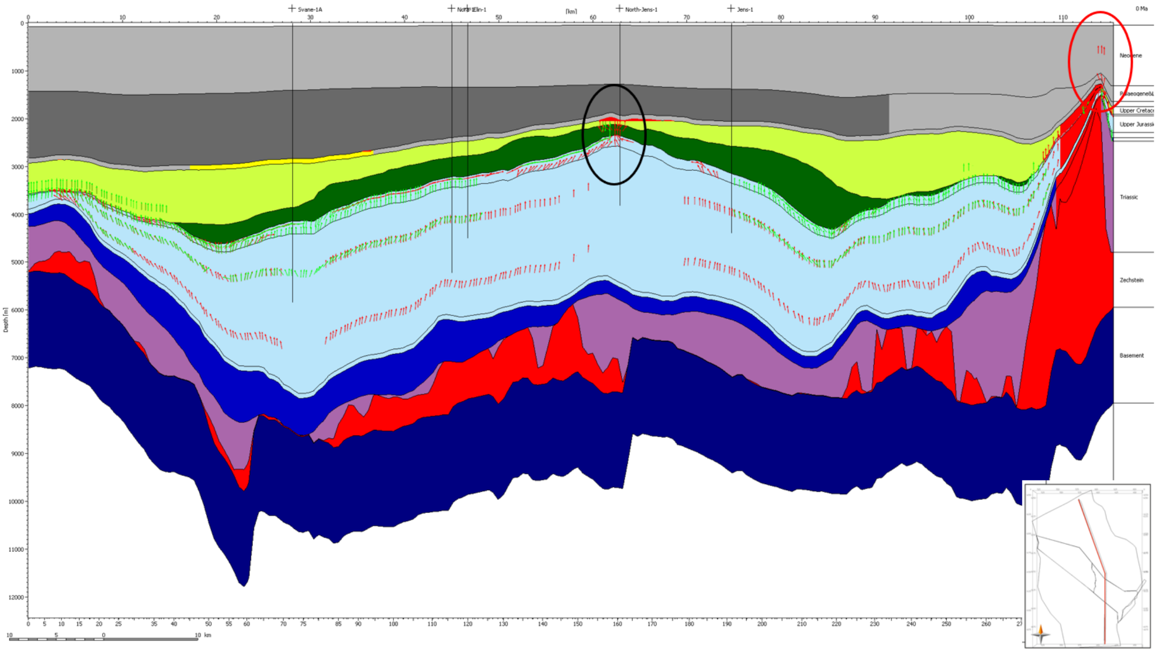

Figure 14: 2D cross section across the 3D BPSM model showing the sedimentary layers with overburden layers in grey colours and the salt diapirs in red. Red line in inset map shows profile line. Notice the accumulation of gas and oil around the North Jens-1 location (black circle), and how gas is lost to the surface (red circle) in the southern part of the line in the Dutch sector.

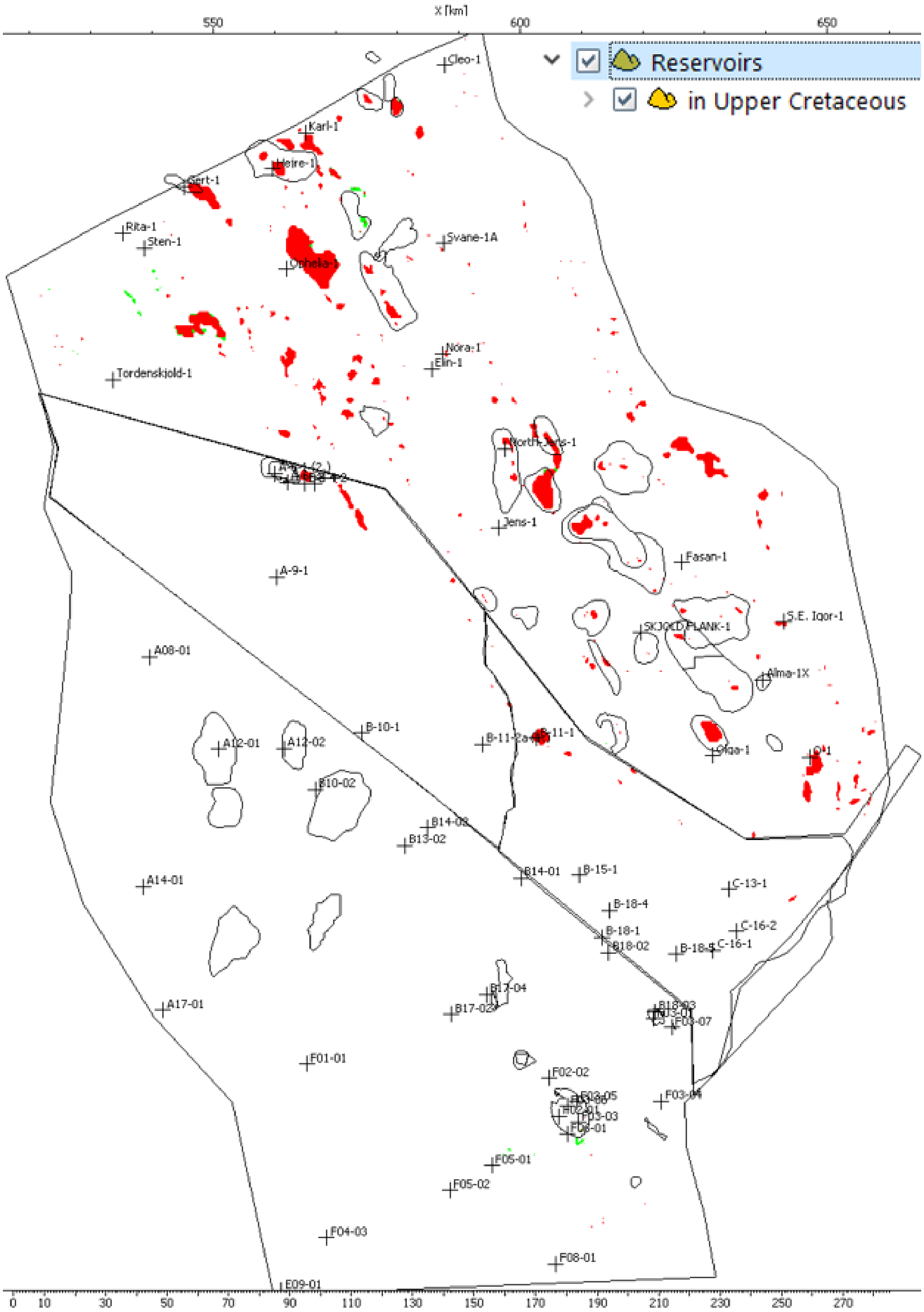

Figure 15. Map showing the distribution of accumulated hydrocarbons in the Upper Cretaceous reservoir layer based on the unconventional 3D BPSM model. Notice that major accumulations mainly occur in the Danish area.

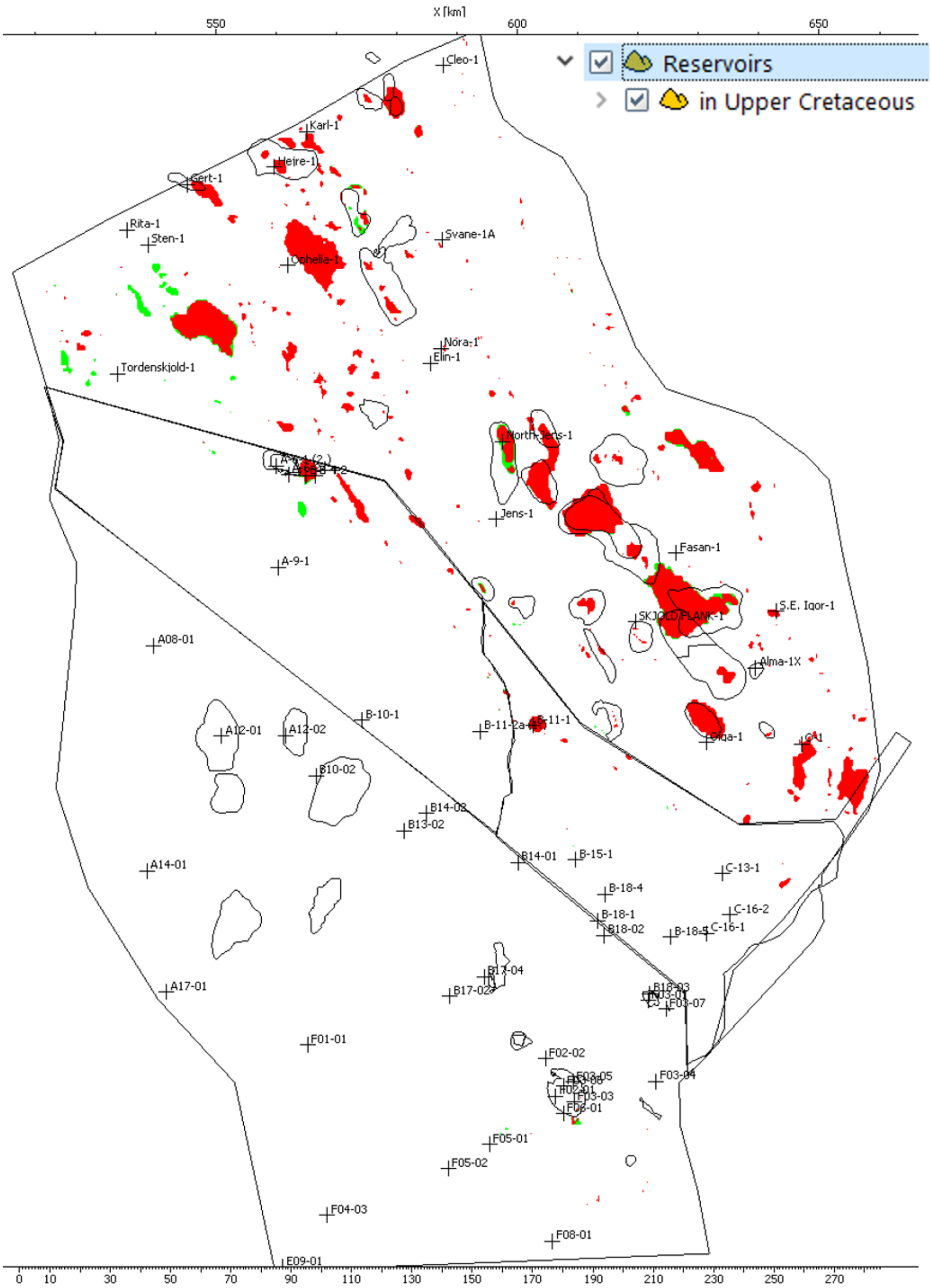

Figure 16. By changing reservoir properties and various facies distributions, it is possible to better match the known accumulations (compare with Figure 15).

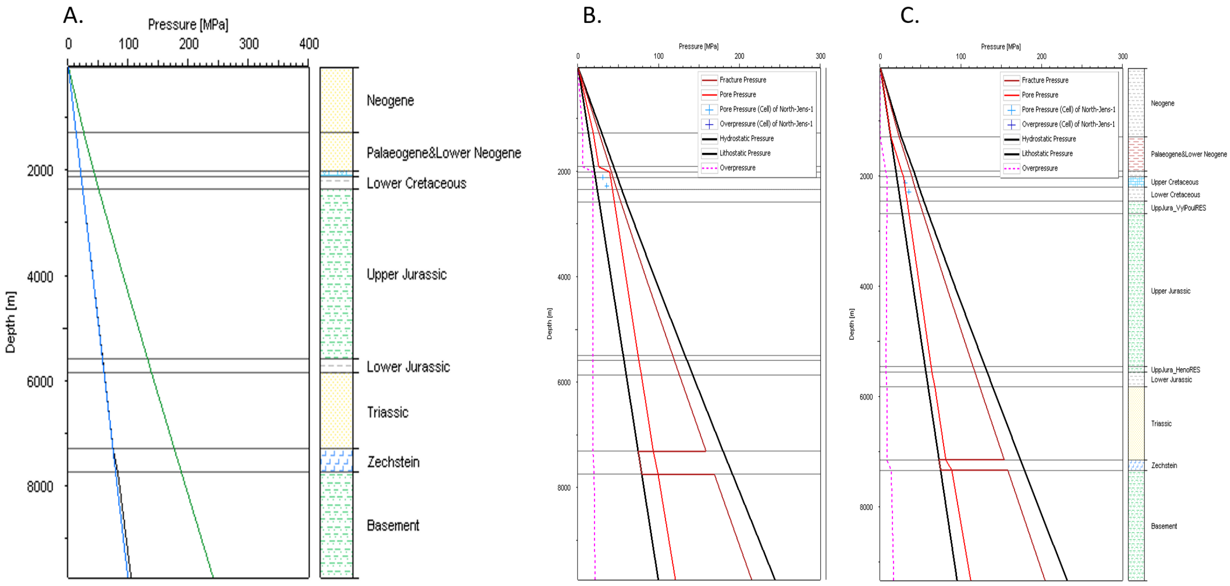

Figure 17. 1D extracted model results that show the impact on the pore pressure modelling at the Jens-1 well, when changing overburden facies to mimic overpressure build-up. Plot A. is a model scenario without overpressure build-up (Figure 15), while plots B. and C. represents various degrees of overpressure build-up depending on selected overburden facies (Figure 16).

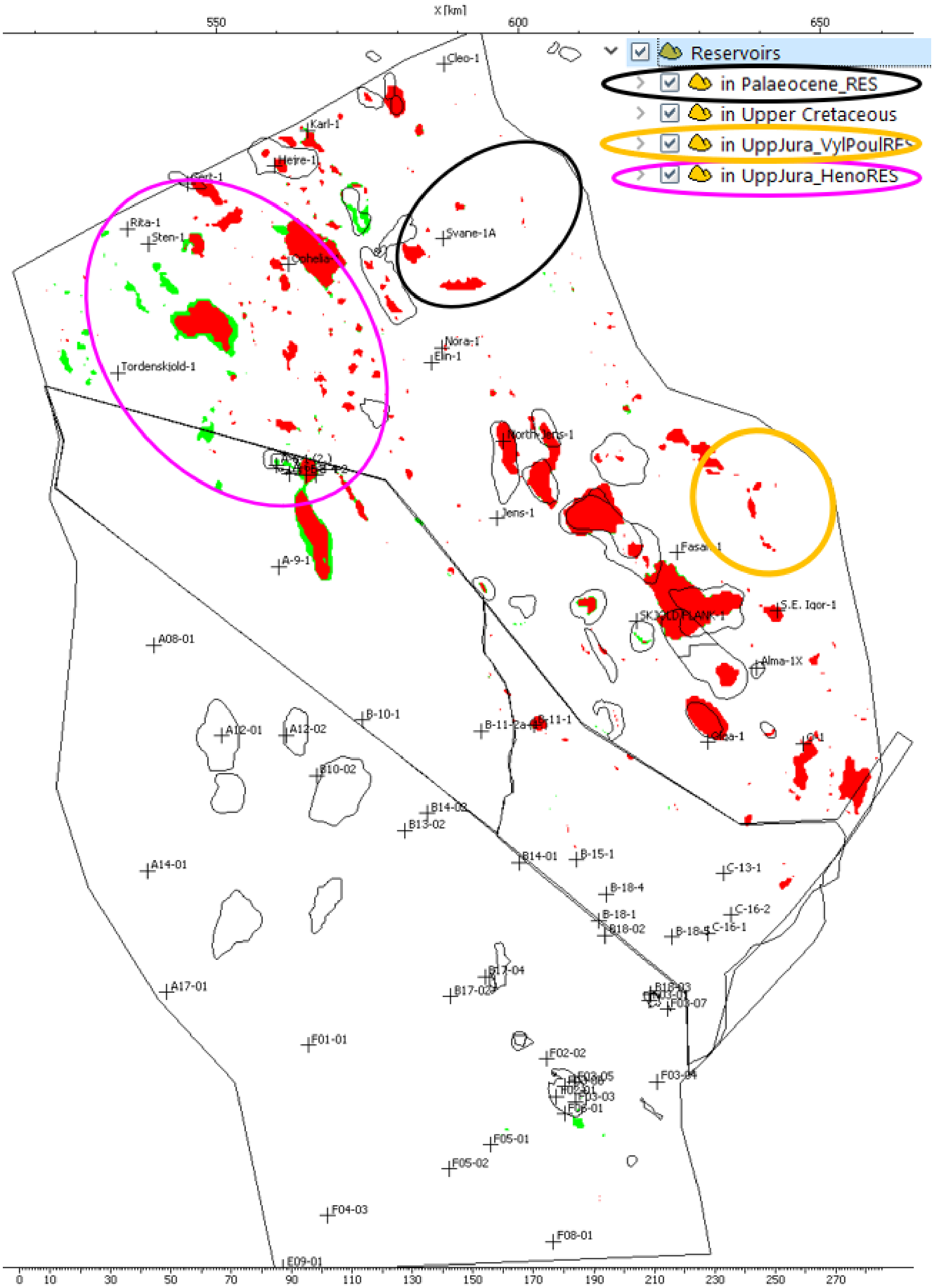

Figure 18. Example showing the distribution of accumulations after introducing more reservoir layers and tighter shaly lithologies in the overburden to force pressure built-up in the upper part of the Cenozoic section (see Figure 17). The areas marked by coloured circles represent areas where majority of HCs are accumulated in the individual reservoir layer shown in the upper right corner. Remaining accumulations not encircled are areas where HCs accumulate in Upper Cretaceous reservoir.

5 ESTIMATION OF CONVENTIONAL RESOURCES

5.1 Review of conventional resources

The previous study of the unconventional in-place resources showed that the calculated amounts of hydrocarbons accumulated in the individual source rocks could be listed for each country (see GARAH Deliverable report, 2.4 (Lutz et.al. (2021) for more details). This study shows that most of the in-place resources are found in the two Danish source rocks, especially in the Bo Mb of the marine upper Farsund shales and in the Middle Jurassic Bryne coaly source rocks (Figure 15).

To further assess potential conventional resource estimations for the three countries available information are reviewed and summarised below. Notice that units for resources and reserves may vary between countries. In this report, the original data is reported as well as being converted into metric units, which are used by Denmark, Germany and the Netherlands.

5.1.1 Denmark

The Danish Central Graben is a mature petroleum province with the principal petroleum source rocks being the Upper Jurassic–lowermost Cretaceous marine Farsund Formation shales and with minor contributions from Middle Jurassic coaly units of the Lola, Bryne and Lulu Formations. Most Danish oil and gas production are from porous chalk reservoirs in the Ekofisk and Tor Formations i.e. the upper part of the Chalk Group. The dominant trap type is a 4-way structural closure over salt structures or on inversion anticlines (e.g. Figures 12 and 14). Despite a very mature exploration stage where all known structural traps at the chalk level have been drilled, discovery of the fields where HC's are trapped in a quasi-dynamic state as the Halfdan Field exist. Deeper parts of the Chalk Group (Hod & Hidra Fms) are also prospective in areas where high overpressure has preserved porosity in the chalk. More conceptual play areas, located east of the AOI of this study, in the Siri Canyon and include parts that have experienced long-distance migration of hydrocarbons generated within the Central Graben deeply buried Farsund Fm.

Between 1993 and 2017, Denmark was one of the largest oil exporting countries in Europe having gained this position from its share in the highly prolific Danish Central Graben, whereas the area outside the Central Graben has little and highly uncertain resources. Thus, Denmark was for many years net exporter of oil and gas. This is no longer the case due to tailing production rates. Until 2020, Denmark was in the middle of the 8th licensing round, where 4 companies had applied for 5 licenses in the North Sea west of the 6 deg. 15 min longitude. The 9th Licensing round was supposed to be announced 12 months after the grant of licenses from the 8th round. By Early 2021, all coming licensing round incl. the 8th licensing round (and Oil and Gas exploration) was put on hold. Revised legislation now limit new HC exploration possibilities to the North Sea, with open door applications east of 6 deg. 15 min longitude (see https://ens.dk/en/our-responsibilities/oil-gas).

The Danish Energy Agency (DEA) makes an annual assessment of Danish oil and gas resources based on a pre-defined classification system. The aim of the classification system is to determine resources in a systematic way (see https://ens.dk/en/our-responsibilities/oil-gas/resources-and-forecasts).

GEUS have been further assessed the resources and reserves by dividing the Danish Central Graben (DCG) area into 11 main Play type maps (Figure 19; Appendix 2; Schovsbo et al., 2020b), where most HCs are produced from the following main Plays types:

A. The Upper Cretaceous to Palaeogene Chalk Play ('3. Upper Cretaceous (Ekofisk & Tor Fms), Appendix 2) has been most successful in Denmark, followed by the lower Cretaceous Chalk Play ('5. Lower Cretaceous (Tuxen & Kraka Fms), Appendix 2)

B. The Middle Jurassic sandstones ('10. Middle Jura Sandstone', Appendix 2) are more successful than Upper Jurassic sandstone that only became on stream within the last years.
C. The most recent sandstone reservoir is found in Miocene sand.
D. Upper Jurassic sandstone under HP/HT conditions is viewed as underexplored
E. Future exploration is expected to be associated with Jurassic and Lower Cretaceous turbidite sands.
F. Conceptual emerging plays types include biogenic gas in Miocene or younger reservoirs, diatomite reservoirs and fractured basement in basement highs and plays that depend on long distance migration from the Central Graben (i.e. Siri Canyon sandstones) or pre-Mid Jurassic source rock interval to charge.

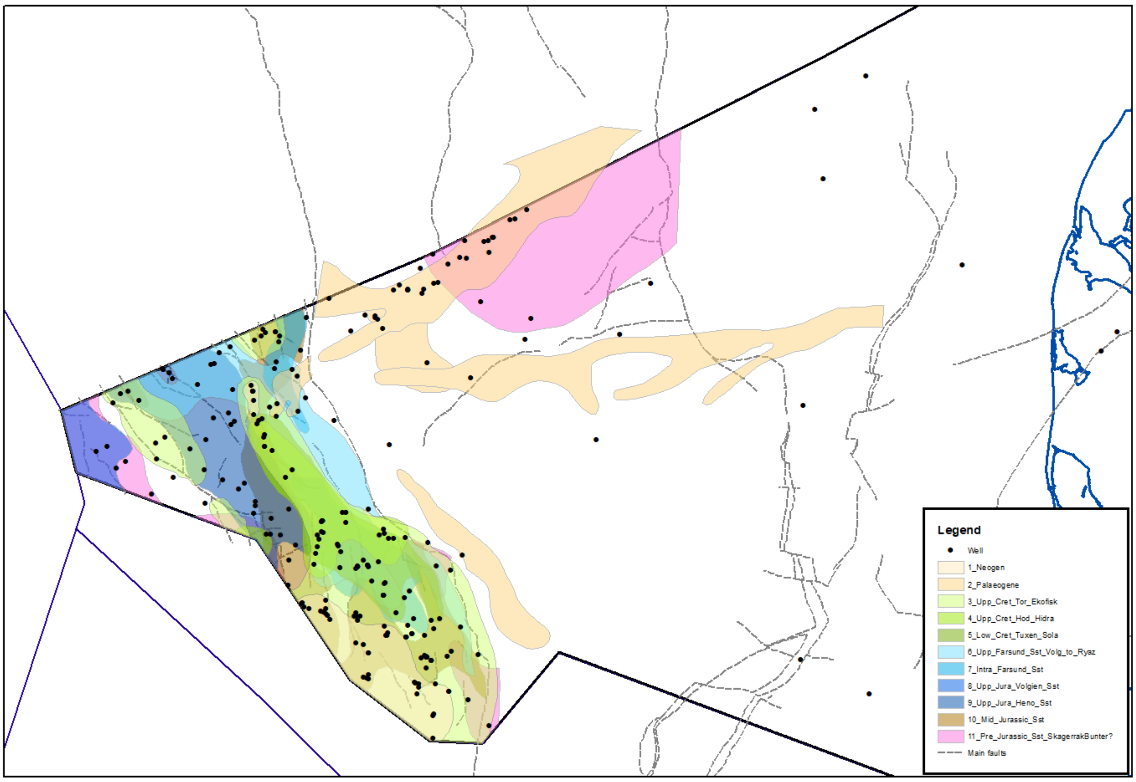

Figure 19: Map showing the geographical extent of the 11 main Play types in the Danish Central Graben (DCG) area (see Appendix 2 for more detailed Play type maps)

In each of the 11 Plays types it can be assumed that the accumulated HC's have been expelled and migrated from the following main petroleum source rocks:

- Upper Jurassic – lowermost Cretaceous Farsund Formation.
- Middle Jurassic coaly units of the Bryne and Lulu Formations constitute a secondary source.
- An unknown contribution may come from other source rocks including the Upper Jurassic Lola Formation, the Lower Jurassic Fjerritslev Formation, Permian shales and Carboniferous coals.

It is important to note that technically recoverable resources - not determined in this study - will be significantly less, in general at least one order of magnitude.

For each Play type area, the resource is estimated based on an evaluation of 21 discoveries and 72 prospects and leads (Table 1).

Table 1: Summary of estimated reserves and resource in Denmark pr. 1/1-2021 from eth Danish Energy Agency (high prognose). GEUS resources for Yet-to-find is from Andersen et al. (2015; reported in Schovsbo et al. 2020b)

PT No.	Play Type	Proven Discoveries			Yet-To-Find			
		Category 1 (mill m^3 oe)			Category 2+3 (mill m^3 oe)			
		Discoveries	P50	Prospects and Leads	P50 (non-risked)	Posibble extra resources	P50 (risked)	Posibble extra resources
1	Neogene	1	10	5	65		18	
2	Paleogene	3	21	2	3		0	
3	Upper Cretaceous (Ekofisk & Tor Fms)			12	223	25	45	2,2
4	Upper Cretaceous (Hidra & Kraka Fms)	4	25	4	41		4	
5	Lower Cretaceous (Tuxen & Sola Fms)	1	29	3	41		19	
6	Upper Jurassic (Upper Farsund Sst)			9	189		30	
7	Upper Jurassic (Intra Farsund Sst)	1	44	4	81	20	27	2
8	Upper Jurassic (Outer Rough Sst)			3	44		7	
9	Upper Jurassic (Heno Fm)	5	78	15	102		21	
10	Mid Jurassic Sandstone	6	39	11	38	15	9	1,5
11	Pre-Jurassic			4	30		4	
	Total	21	246	72	857	60	184	5,7
					917		189,7	

Summary Resources and Reserves (1/1 2021) *Danish Central Graben (DCG)*	Gas 10^9 Nm^3	Oil 10^6 m^3	Oil eq 10^6 m^3			
Produced	183	447				
Reserves	29	65				
Contingent resources	45	80				
Technological resources	1	15				
Exploration	6	22				
Discoveries (P50)			246			
Prospects and leads (catagory 2+3) - Unrisked (P50)			857			
Prospects and leads (catagory 2+3) - Risked (P50)			184			
Possible additional resources - Unrisked (P50)			60	Cat..(1+2+3)	1163	unrisked
Possible additional resources - Risked (P50)			6	Cat..(1+2+3)	436	risked

The data availability and status of reserves and resource have further been addressed in GARAH Deliverable Report, 2.3. The report also evaluated the yet-to-find resource in Denmark based on the evaluation by Andersen et al. (2015 reported in Schovsbo et al. 2020b; Table 1).

The yet-to-find resources include:

- Discoveries (Category 1) under evaluation,
- Prospects and leads (Category 2+3) - Unrisked,
- Prospects and leads (Category 2+3) - Risked,
- Possible additional resources - Unrisked.
- Possible additional resources - Risked.

From Table 1 the total estimated reserves and resources sums up to 1107 $x10^6$ m^3 oil equivalents with 917 $x10^6$ m^3 unrisked oil equivalents (Category 2+3 + possible additional resources) or ~190 $x10^6$ m^3 risked oil equivalents (Category 2+3 + possible additional resources).

5.1.2 Germany

For Germany there is no published official resource report. The A6/B4 Field is the only offshore natural gas field and it is sourced by Carboniferous source rocks. ~10 Billion m^3 of natural gas were produced and the A6/B4 Field is about to be closed soon (LBEG, 2021).

Some local accumulations are shown in the 3D model and demonstrate a resource potential. However, due to the patchy distribution of the Mesozoic source rocks in the German Central Graben, the strong structuration of the rift and the unknown reservoir distribution, we do not quantify the resources based on the regional model.

5.1.3 Netherlands

In the Netherlands the conventional reserves and resources are assessed and published in a yearly report (Annual report 2020 - Natural resources and Geothermal energy in the Netherlands, https://www.nlog.nl/index.php/en/annual-reports). This assessment uses the PRMS classification and makes a subdivision into oil and gas resources from Reserves and Contingent Resources – Development Pendig for the on and offshore area of the Netherlands (Tables 2 and 3). It also gives a general model for yet-to-find resources (for a detailed breakdown of the assessment see GARAH Deliverable Report 2.3). This assessment summarizes all plays in the Dutch on- and offshore as described in GARAH Deliverable Report 2.2 and 2.3 as well as Doornenbal et al. (2019b). A comparison with the values from the 3D model is difficult due to the focus on the northern offshore area as well as the exclusion of the Carboniferous gas source rocks.

Table 2: Dutch natural gas resources as of 1 January 2021 in billion Nm^3. (Annual report 2020 - Natural resources and Geothermal energy in the Netherlands, https://www.nlog.nl/index.php/en/annual-reports).

Area	Reserves	Contingent resources (development pending)	Total
Groningen	6.6	-	6.6
On land	28.4	32.9	61.3
At sea	57.4	12.9	70.3
Total	92.4	45.8	138.2

Table 3: Dutch oil resources as of 1 January 2021 in billion Sm^3. (Annual report 2020 - Natural resources and Geothermal energy in the Netherlands, https://www.nlog.nl/index.php/en/annual-reports).

Area	Reserves	Contingent resources (development pending)	Total
Land	9.2	5.0	14.1
Sea	2.5	13.0	15.5
Total	11.6	18.0	29.6

Cumulative natural gas production from all offshore fields until the 1 January 2021 amounts to 792.321 billion Nm^3. Cumulative oil production from all offshore fields until the 1 January 2021 amounts to 64.692 billion Sm^3.

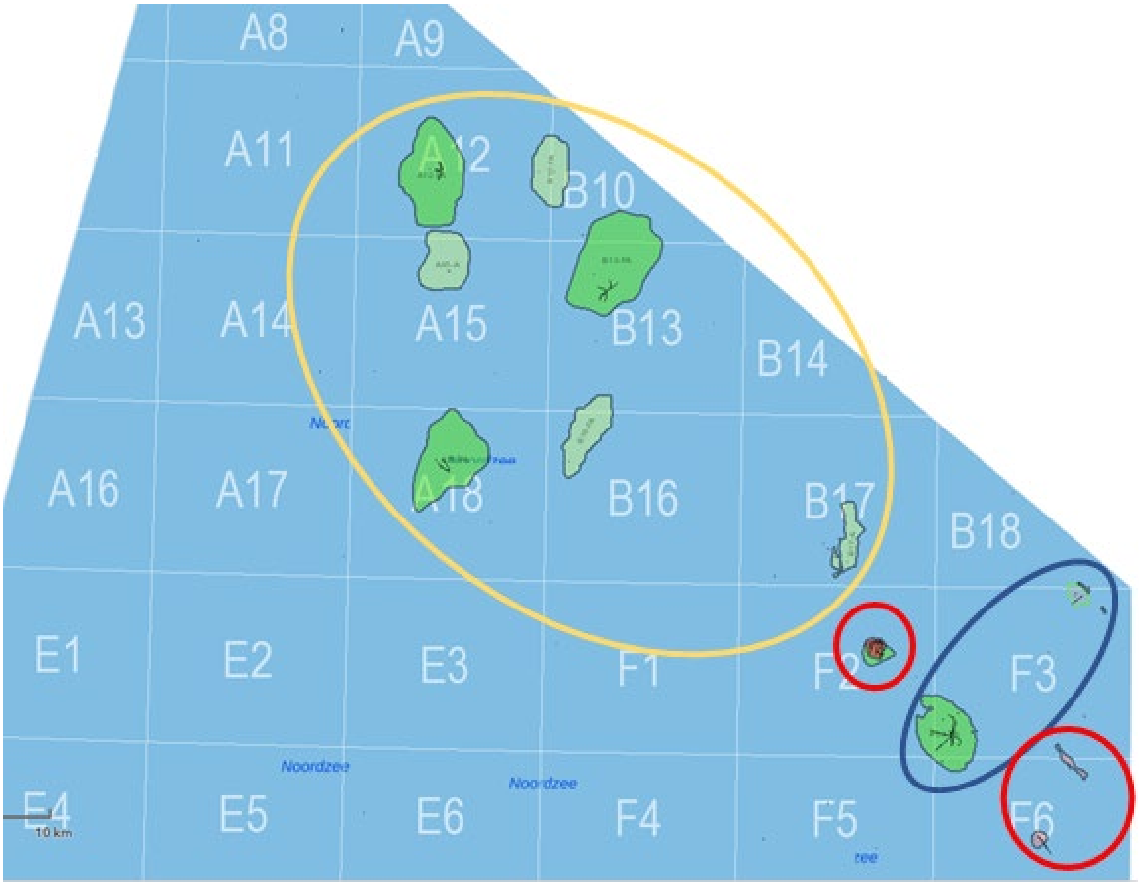

Figure 20. The map shows the stratigraphy of the fields in the Dutch offshore area of the 3D BPSM model. Fields in in the yellow circle represent shallow gas fields; fields in the red circle represent Upper Cretaceous (Ekofisk Fm) fields, while fields in the blue circle represent Upper Jurassic/Lowermost Cretaceous (modified from www.nlog.nl). Please note that the image uses green for gas and red for oil accumulations.

The main reservoir intervals – apart from the shallow gas plays – in the Dutch part of the 3D model area are located in the Upper Cretaceous and in the Upper Jurassic (Figure 20). Results from the 3D BPSM modelling indicate the migration and accumulations of oil into the larger southern F03 structure can be reproduced. These accumulations occur in the Upper Cretaceous, while the actual reservoir of that field is located in the Upper Jurassic. This is due to the resolution of the model and the difficult and very heterogeneous reservoir facies in the Upper Jurassic in the Dutch part.

Furthermore, some of the smaller fields in the south-eastern part of the model would receive migrated HCs. The B18/F03 fields on the German border were probably source from patches of Posidonia Shale in Germany. In the present 3D BPSM model an active local source rock with focus on detailed migration has not been part of the study.

5.2 Estimation of conventional resources from the 3D BPSM

To communicate the estimated basin modelling results, the 11 pre-defined Play type areas described above are used as a reference (see Figure 20 and in detail in Appendix 2). The main conventional Play type maps are harmonised in the GARAH project (see also GARAH Deliverable Report, D2.3). Here the assessment of the total estimated oil and gas reserves and resources are assessed in more detail.

Following this Play type-based break-down most resources in the 3D BPSM study area are present in the Upper Cretaceous – Paleogene Chalk play (Ekofisk & Tor) followed by the Upper Jurassic and Mid-Jurassic sandstone plays and Palaeocene sand in the Siri Canyon. High risk plays where no production has yet been established include sandstone reservoirs of Miocene sand, Upper Jurassic sandstone under HP/HT conditions and Jurassic and Lower Cretaceous turbidite sands.

In order to compare the estimated 3D BPSM modelling results with the reviewed and summarized resources described in Section 5.1.1 the results focus on examples from the Upper Cretaceous play (Ekofisk & Tor) and the Upper Jurassic sandstone plays.

Analysis of the 3D BPSM model results show that the drainage and migration flow paths are mainly structure controlled, filling structures before remaining residuals are spilled to other accumulations and structures. Analysing local accumulations reveal that 'Break Through migration' due to failure in seal integrity also is possible. In local areas, the seals are ineffective and results in incomplete filling, thus not filling the structure/accumulation to spill-point (e.g. Figures 14 and 18; i.e. in the Dutch area).

The total calculated conventional amounts in Table 4 show that the Upper Cretaceous Chalk reservoir receives most of the generated hydrocarbons. Comparing the values from the BPSM study with the reserves and resources from the Danish assessment (Schovsbo et al. 2020b) shows that the Upper Cretaceous Chalk (Ekofisk & Tor Fms) (green marked values in Table 4) receives about twice the resources calculated for the Danish Central Graben area (i.e. unrisked total of 1163 mill m^3 oe in Table 1 (246 (Category 1, Discoveries) + 917 mill m^3 oe (Category 2+3, Yet-to-find & possible additional resources) vs. 1998 mill m^3 oe from BPSM). Keeping in mind that the 3D model is of a large regional extent and that the software in the PetroReport output-module calculates and sums up every little accumulation, some of which can be artefactual, these calculated values from the model are in good agreement with the values in Table 1.

Table 4. Example showing one model result of calculated conventional amounts. The scenario run is the same as shown in Figure 18 and shows the calculated values from the PetroReport for selected Play types (first two columns for gas (red column) and oil (green column), in the last column the total amounts are converted to x10^6 m^3 oe. Notice that not all the Play types are implemented into the 3D BPSM model (grey rows, Play type No. 4, 5, 8) and the Upper Cretaceous Chalk reservoir receives most of the migrated and accumulated HCs.

PT No.	Play Type	Reservoir / Carrier	GIIP	OIIP	Total eo
			Accumulated volumes (From PetroReport) (10^6 t)	Accumulated volumes (From PetroReport) (10^6 t)	Accumulated Unrisked (10^6 m^3 oe)
2	Paleogene	Paleocene_RES	0,08	12,65	13
3	Upper Cret. Chalk (Ekofisk & Tor Fms)	Upper Creteceous	896,02	1101,69	1998
4	Upper Cret. Chalk (Hidra & Kraka Fms)				
5	Lower Cret. (Tuxen & Sola Fms)				
6-7	Upper Jura. (Upper Farsund Sst)	Upp_Jura_VylPoulRES	0,02	4,64	5
8	Upper Jura. (Outer Rough Sst)				
9	Upper Jura. (Heno Fm)	UppJura_HenoRES	71,27	3,79	75
10	Mid Jurassic Sandstone	(Lower-)Mid JurassicRES	0,00	0,00	0

6 CONCLUSIONS

The model presented here is the first publicly presented 3D basin and petroleum system model across the Danish, German and Dutch Central Graben area. It was built in close cooperation between the GARAH and 3DGEO-EU projects within the Geo-Energy theme of GeoERA. It serves as a pilot-study to identify cross-border issues on horizon correlation. These harmonised datasets can in the future act as first-step 3D model to further assess play maps created for each country.

The cross-border model covers the Danish, German and Dutch Central Graben and its surrounding flanks, incorporating their distinct geological evolution. The model includes several of Central Europe's most prolific petroleum source rocks and captures their regional differences in maturity and quality.

Based on the source rock distribution in the three countries, the model calculates the total generated HCs and their migration history. Furthermore, sensitivity analysis can be performed and changing of critical input parameters shows how a more detailed 3D model can be created to improve the resource assessment.

Hydrocarbon expulsion calculations were only performed for the two key proven source rock intervals, the Upper Farsund marine source and the Middle Jurassic coals. During the geological evolution of the 3D BPSM study area, especially through the Cretaceous in the Danish Central Graben (DCG), the petroleum system continuously expanded with HC expulsion but was followed by lower expulsion rates in the Paleocene and Neogene. In local marginal areas, significant expulsion resumed in the Miocene and continued up to present day.

Even though, the use of a relative migration model, e.g. not taking into account more detailed hydrodynamic effects and the heterogeneous permeability distribution within the Chalk Group, the BPSM model gives reasonable migration flow paths from source areas to mainly structural accumulations and shows how the resulting distribution of accumulations rely on various fill and spill scenarios.

Some of the modelled accumulations are larger than the actual fields which can be a result of the simplified regional migration model. Other fields show too small volumes of accumulated HCs and indicate that expelled volumes are too small, maybe due too low source rock quality or that additional volumes from other drainage areas are necessary to match proven resource estimates. Furthermore, the Farsund source rock maturity may not be high enough to expel sufficient amounts of HCs.

Uncertainties in the 3D model are not evenly distributed, basically due to varying data coverage and density in the three modelled sectors of Denmark, Netherlands and Germany. However, in the future, the 3D model can be further refined for more detailed studies with higher model resolution, e.g. by including faults and fault bounded structures using the HIKE dataset, with focus on smaller structural areas or on specific source rock layers. Thus, the 3D BPSM model is a good starting point for more detailed yet-to-find assessments and may focus interest towards areas which at present are underexplored and need further assessment.

Additionally, the 3D basin and petroleum system model is not limited to petroleum assessments, but can be utilized for other studies, where basin and temperature evolution are critical for the 3D subsurface geological and petrophysical assessment e.g. within utilisation of geothermal energy or underground CO_2 or hydrogen storage.

Acknowledgment

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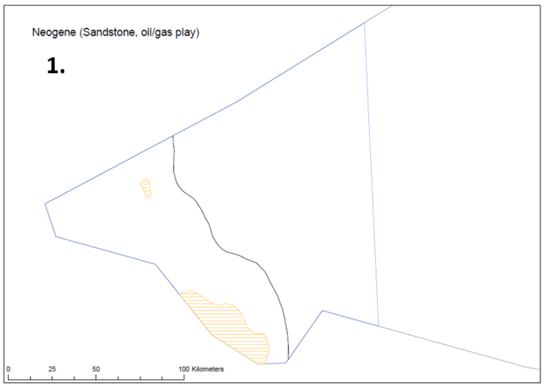
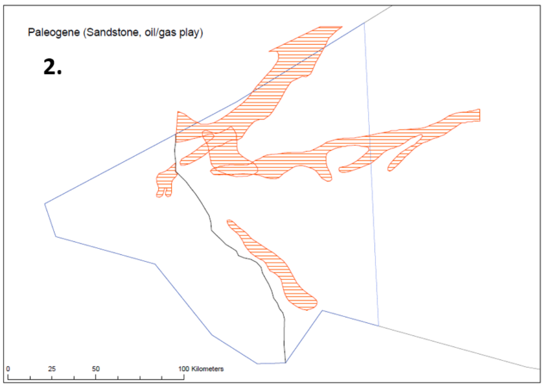
8 APPENDICES

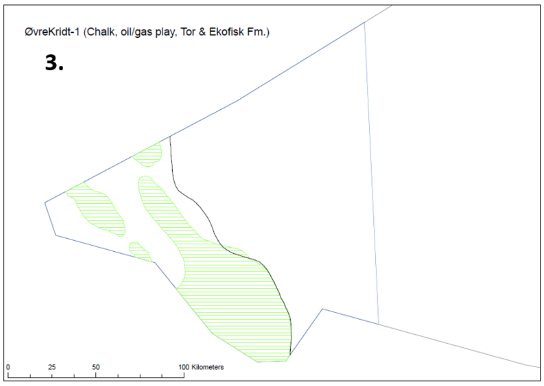
Appendix 1 : Petroleum System Model - Parameters Spreadsheet.

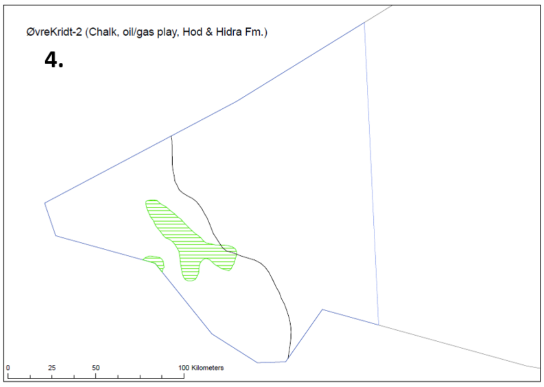
GARAH 3D Petroleum System Model (input parameters for PetroMod)	Data availability		
	TNO	GEUS	BGR
Present-day input			
Absolute ages of horizons	Absolute ages of horizons have to be defined together		
Lithology	Generalized lithology based on unit/formation description - See excel	Generalized lithology based on unit/formation description	Generalized lithology from well reports
Facies maps	uniform	uniform	uniform
Fault surfaces (main faults in the study area)	Can provide major fault lines	Work needed to create consistent major faults	Schillgrund Fault, Mads Fault, boundary faults of Clemens Basin
Paleo Geometry			
Erosion events	Mid-Jurassic (Mid-Kimmerian), Upper Cretaceous (Subhercynian), Paleocene (Laramide) and MMU - See tectonostratigraphic chart	- Mid-Jurassic (Mid-Cimmerian) - Late Cretaceous erosion - MMU erosion	• Mid-Jurassic (Mid-Cimmerian) • Late Cretaceous erosion • MMU erosion
Erosion maps - Paleo thicknesses of eroded formations	Erosion estimates from previous 1D and 3D studies based on seismic data and present-day thicknesses	Estimated erosion based on seismic data and present day thicknesses	Estimated paleo thicknesses based on seismic data and calculated present day thicknesses in graben systems in the Entenschnabel area
Salt maps, intitial salt thicknesses, and salt activity during the geological periods	Paper Johan ten Veen 2012 NJG	Salt diapirs are based on Top Zechstein surface-grid including the salt polygons	Salt diapirs are included in the 3D model using the top Zechstein surface-grid including the salt polygons
Boundary conditions			
Heat flow data	Calculating new maps based on PetroMod model with PetroProp	Simple regional heat flow trends	Two areas with different heat flow trends
Palaeo water depths	Same PWD trends are used for our models	Simple regional PWD trend maps	Paleowater depth (PWD) based on PWD trends of adjacent areas (Verweij et al. 2009; Abdul Fattah et al. 2012)
Calibration data			
Vitrinite reflectance data	see table	more than 40 wells with VitRef data	16 wells with vitrinte reflectance data
Tmax	see table	some wells with Tmax	3 wells with Tmax
Temperature	see table	more than 40 wells with Temp data	6 wells with temperature data
Source rocks and their properties			
Upper Jurassic (Clay deep, Kimmeridge, Lola FM)	not included in models until now	Late Jurassic- Early Cretaceous Farsund Fm; Kinetics: Pepper & Corvi (1995)	• HI 430 mgHC/gTOC • TOC 8% • Kinetics Vandenbroucke et al. (1999), TII North Sea (uniform values)
Lower Jurassic (Posidonia Shale)	HI: 400, TOC: 6%, Kinetics: Pepper&Corvi TII(B)	Middle Jurassic Bryne Fm; Kinetics: Pepper & Corvi (1995)	• HI 400 mgHC/gTOC • TOC 8% • Kinetics Vandenbroucke et al. (1999), TII North Sea (uniform values)
Reservoir rocks			
	Paleogene Upper Cretaceous chalk Upper Jurassic sands	Upper Cretaceous - Chalk Group Jurassic sands	Upper Cretaceous - Chalk Group Jurassic sands

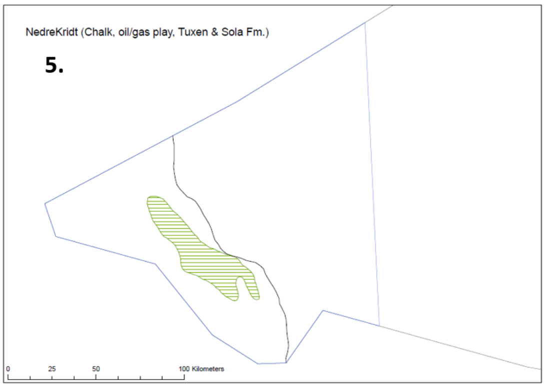
Appendix 2 : the 11 pre-defined Play type areas (from Schovsbo et al. 2020).

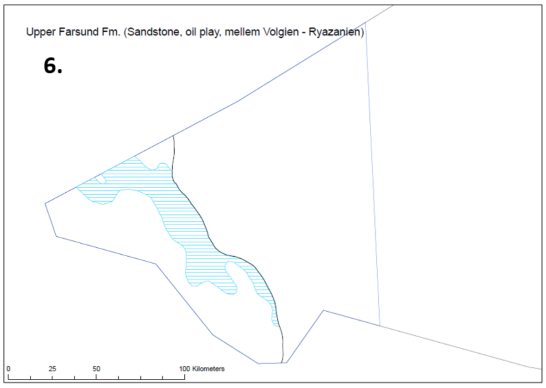


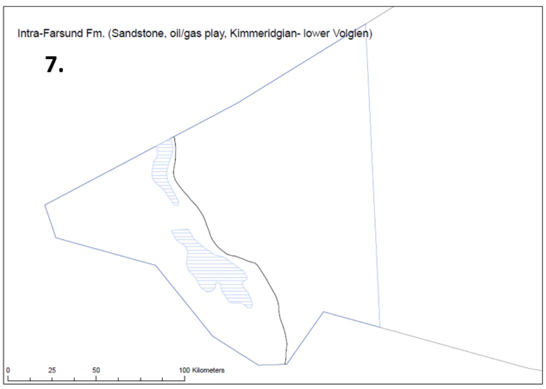


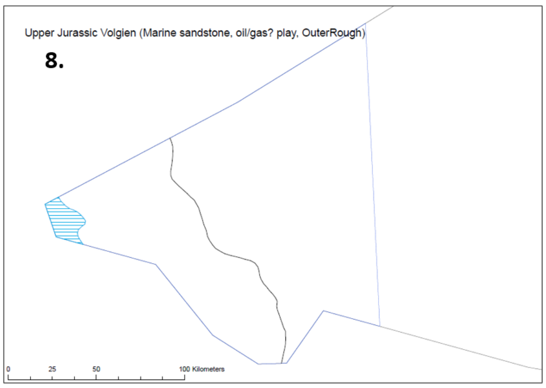


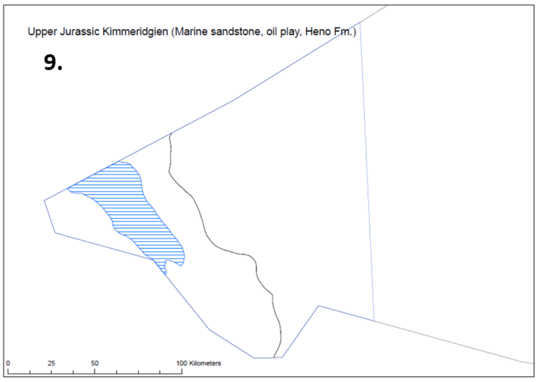


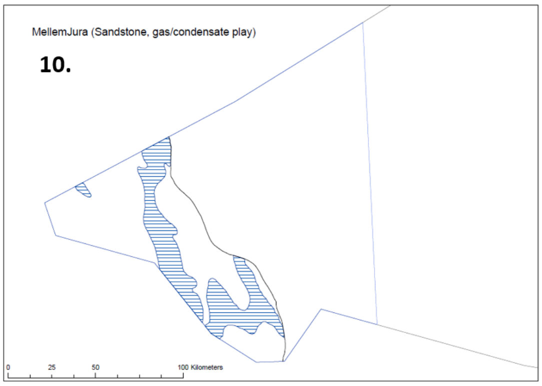


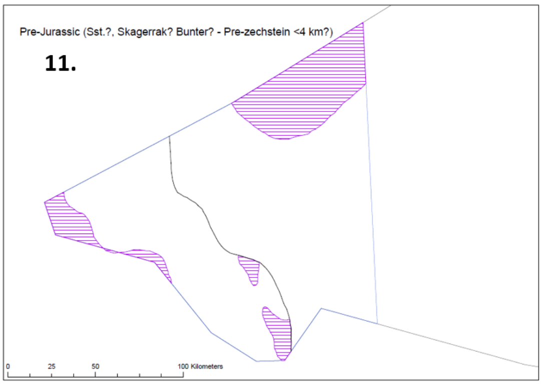







Upper Jurassic Kimmeridgien (Marine sandstone, oil play, Heno Fm.)
9.
0
25
50
100 Kilometers


MellemJura (Sandstone, gas/condensate play)
10.
0
25
50
100 Kilometers


Pre-Jurassic (Sst.?, Skagerrak? Bunter? - Pre-zechstein <4 km?)
11.
0
25
50
100 Kilometers