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Abstract

This study reflects a simulation study of a typical Brent reservoir with gas cap. A case study has been done on Oseberg Main field, a good example of a Brent reservoir with gas cap, to understand the characteristics and the behavior of the Brent reservoir.

An analogue model 'Beta Brent reservoir' has been defined through the understanding of Oseberg Main field. The history of the 'Beta Brent reservoir' has been simulated from 1991-2016 and considered as the starting point for further drainage strategies to optimize the production from 2016-2045.

The objective of this thesis is to study the impact of different gas export strategies while maximizing the recovery of the oil. However, at first, the impact of injecting more gas on oil recovery has been analyzed and compared to a gas export case (base case). From the results, it is seen that, injecting more gas (import case) in the reservoir will not give significant oil recovery than the gas export. The oil recovery for the import case is almost the same as the base case during 2016-2035. Eventually, in 2045, the oil recovery for the import case and base case are 64.4 % and 63.01%.

Secondly, different gas export rates have been utilized to optimize the base case. Three other different cases have been defined and simulated. From the results, it has been observed that, if the gas export rate is higher, then the oil recovery factor will be lower and the ultimate recovery will be obtained quickly. Base case 3 provides higher amount of oil and gas recovery in early years than the other cases and reaches ultimate recovery of oil (62.82%) by 2030; while the base case reaches ultimate oil recovery (63.01%) in 2042.

Finally, the effect of the duration of particular gas export rate on fluid production performance has been observed. Base case 3 have been analyzed with three different gas export scenarios. From the results, it has been observed that, prolonging the duration of low gas export rate (i.e. delaying maximum gas blowdown) will increase the oil recovery and the total amount of produced gas. However, utilizing high gas export rate (i.e. early maximum gas blowdown) will reduce the oil recovery. Scenario-3 gives the higher recovery of oil (63.12%) while scenario-4 provides the minimum (62.29%).

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Chapter 1

1.1 Introduction

The Oseberg Main field, an oil field with a gas cap, comes at the tail end of its oil production. For the main reservoir, the Brent group, several recovery techniques have been utilized so far. In the beginning, Gas and water injection has been utilized as the main recovery mechanism for pressure maintenance. After a limited pressure depletion (appx. 28 bar) over first few years; the main recovery mechanism has been gas injection. Massive up-flank gas injection in the main field has provided excellent oil displacement. Since, the plateau production of the Oseberg field ended in 1997, mainly gas injection has been used as the drive mechanism in the Oseberg field. A large gas cap has now developed, which will be recovered in the future. Almost 370.9 mill Sm^3 of oil and 43.4 bill Sm^3 of gas has been recovered. The remaining amount of reserve is 31.0 mill Sm^3 of oil and 79.3 bill Sm^3 of gas.[**Appendix A**]

1.2 Project Objectives

The optimization of production strategy is very important in reservoir management, since it will affect the reservoir behavior, which influences future decisions, economic analysis and consequently, attractiveness of projects. Extensive Simulation work shows that the oil recovery factor can be increased by optimizing the gas export strategy.

However, due to confidentiality issues, the full field simulation model results of Oseberg Main can't be published. So, in the first part of the study, the focus is to understand the behavior of the Oseberg Main field and later, the knowledge is implied to create an analogue model for simulation studies; named as the 'Beta Brent reservoir'. In this model, typical properties of a Brent type reservoir have been implemented. However, the wells, historic production, production constraints, and future gas export scenarios and oil production are not identical to those planned for the Oseberg Main field. So, the simulated results and conclusions cannot be coupled to this field.

Different sensitivity analysis has been considered to maximize the oil recovery before going into gas blowdown phase. In this thesis, the objective will be the study of the impact of different gas export strategies while maximizing the recovery of the oil. Therefore, the scope of work can be divided into the following tasks:

- Creating a history model (from 1991-2016).
- Define a base case (2016-2045).
- Define different sensitivity cases to optimize the base case.
- Generate different gas export scenarios with the optimized base case.
- Evaluate effect on fluid production performance for different gas export scenarios.

Defining base cases:

The base case and the other three cases that have been considered to optimize the base case are given below-

Base case : Gas export 0.5 Bsm^3/year from 2016-2020; then gas export 1 Bsm^3/year from 2020-2045.

Base case_2: Gas export 1 Bsm^3/year from 2016-2020; then gas export 2.8 Bsm^3/year from 2020-2045.

Base case_3: Gas export 1 Bsm^3/year from 2016-2020; then gas export 3.5 Bsm^3/year from 2020-2045.

Base case_4: Gas export 0.5 Bsm^3/year from 2016-2020; then gas export 3.5 Bsm^3/year from 2020-2045.

Defining gas export scenarios:

The scenarios that have been considered for Beta Brent reservoir are given below-

Scenario 1: 1 Bsm^3/year in 2016-2020; then maximum export (3.5 Bsm^3/year) from October 2020.

Scenario 2: 1 Bsm^3/year in 2016-2023, then maximum export (3.5 Bsm^3/year)

Scenario 3: 1 Bsm^3/year in 2016-2026, then maximum export (3.5 Bsm^3/year)

Scenario 4: Maximum export (3.5 Bsm^3/year) from Feb. 2016 (‘start blowdown’)

Chapter 2

2.1 Geology and reservoir characteristics

The Oseberg Main field is highly elongated in the north-south direction. The distance between the northernmost and southern most parts of the field is 25 km. The hydrocarbon bearing area covers some 80 km^2. The Field is laterally divided into three main structures by faults. These are the Alpha, Gamma and Alpha North structures. The following figure 1, illustrates the different segment location in Oseberg Main.

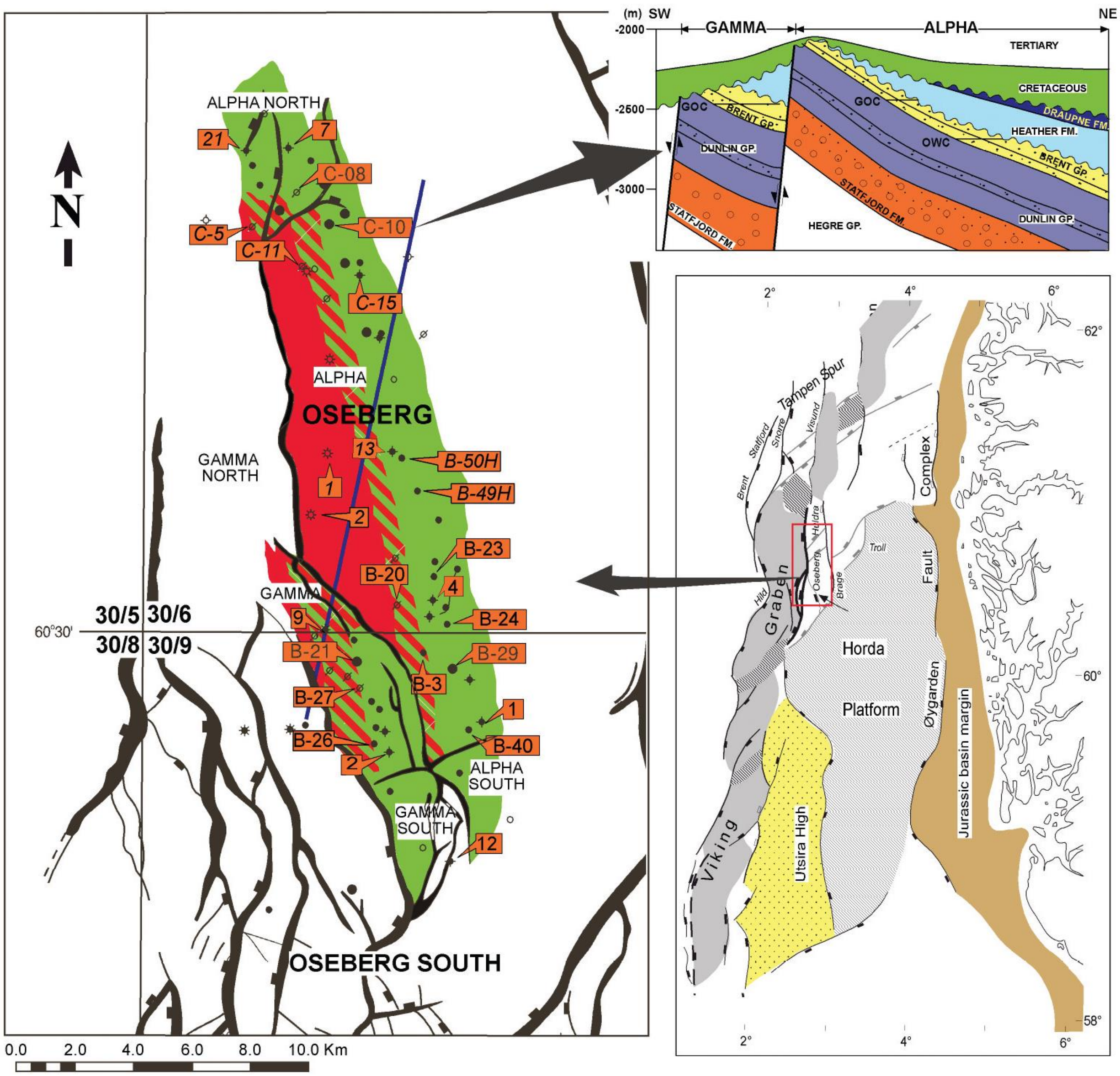

Figure 1: Map illustrating the geographical and structural setting of the Oseberg Main [1]

The reservoirs in the Oseberg Main field are slightly tilted towards the east with a dip of 7^0. The hydrocarbons are contained in the sandstones of the deltaic middle Jurassic Brent group. The reservoirs lie at a depth of 2300-2700 m and generally have excellent reservoir properties. The gas caps are present in all structures. The Alpha structure has a vertical gas column of 380m and an oil column of 210m, for a total hydrocarbon column of about 600m. The Oseberg field reservoir characteristic properties have been presented in table 1.

Table 1: Oseberg field reservoir characteristics: [Modified from [2] and [3]]

Trap/ Rock parameters		
Trap type	Truncated fault block	
Depth to crest	2120 m (subsea)	
Gas-oil contact	2497 m (subsea)	
Oil-water contact	2695-2719 m (subsea)	
Gas column, appx.	380 m	
Oil column, appx.	203-222 m	
Productive Closure, appx.	115 km^2	
Lithology	Sandstone	
Gross thickness:		
Brent group	46-187 m	
Oseberg formation	17-65 m	
Net/gross ratio		
Brent group, appx.	0.70	
Oseberg formation, appx.	0.98	
Porosity (Oseberg Formation)	Avg. range 23.7%	
Water saturation (Oseberg formation)	15%	
Permeability, appx.	2 Darcy (1-3.5 Darcy)	
Hydrocarbons (Alpha and Gamma)		
Stock tank oil density	34^0 API	
Bubble point (at GOC)	280.7 bar	
Solution gas/oil-ratio	Avg. 143 Sm^3/ Sm^3	
Volumes	**OIP (%)**	**GIP (%)**
Alpha Structure	56	60
Gamma Structure	31	17
Alpha North Structure	13	3

Oseberg Main produces from different fault segments and formations. The reservoirs in the Brent Group is subdivided into five formations- Oseberg, Rannoch, Etive, Ness and Tarbert.
In a regional context, deposition of Brent sediments consisted of three major phases According to Graue et. Al [4]:

1. Aalenian lateral infill of sandstones from the east. This resulted in the deposition of the fairly localized but thick fan delta sandstones across the Oseberg area. These deposits are referred to as the Oseberg formation.

2. Late Aalenian to early Bajocian progradation of the Brent delta from south to north. This led to the deposition of the delta front/ beach sandstones of the Rannoch and Etive formations and the delta plain deposits of the Ness formation.

3. Early Bajocian to early/middle Bathonian retreat of the Brent delta, resulting in deposition of delta plain deposits of the Ness formation and finally deposition of beach and shallow marine sandstones of the Tarbert formation. At least two major pulses of transgression have occurred: one took place before the onset of the Tarbert deposition, and the other was the final transgression of the Brent delta in this area.

The regional stratigraphic aspects of the Brent group are illustrated in a simplified form in figure 2,

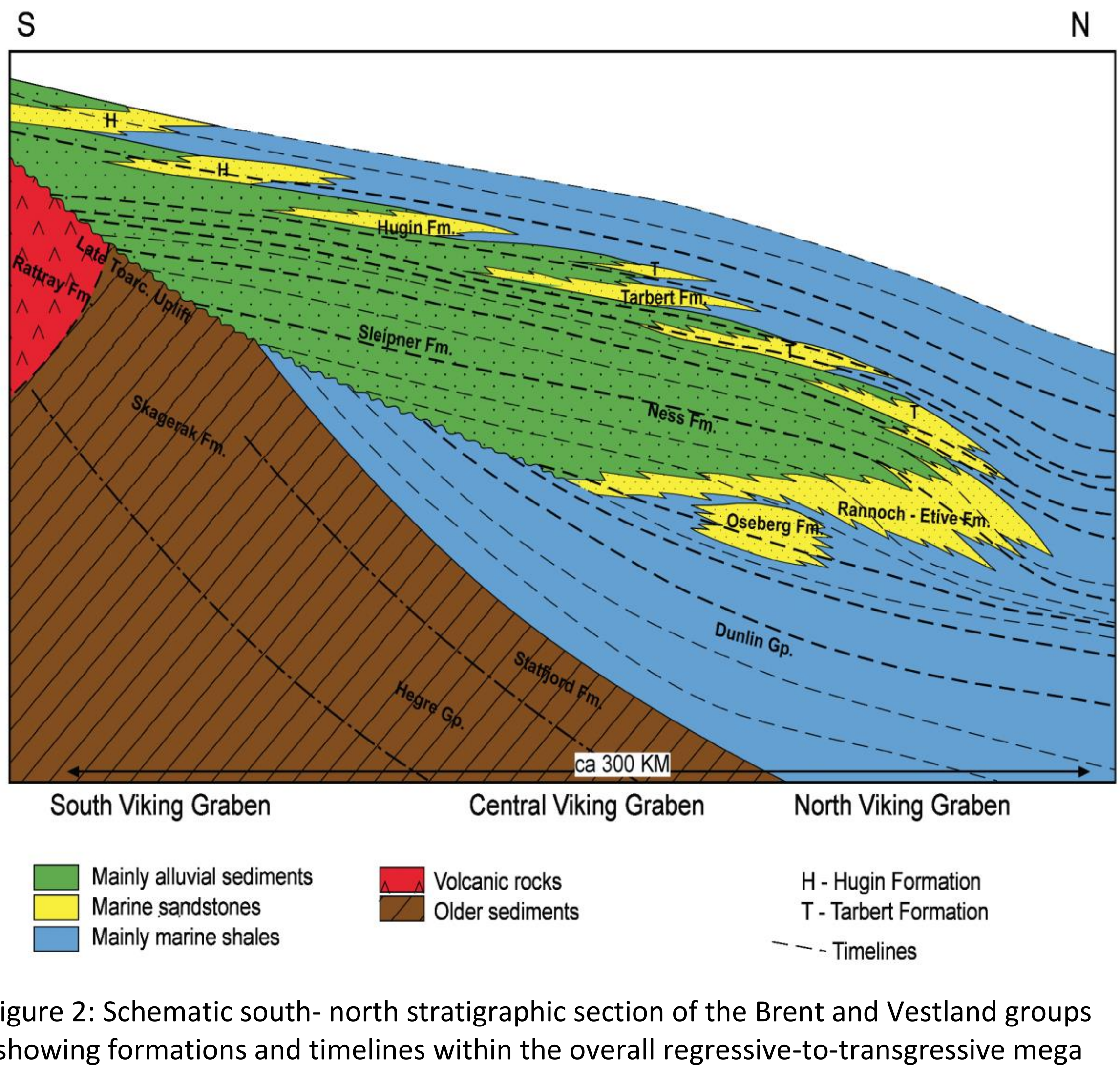

Figure 2: Schematic south- north stratigraphic section of the Brent and Vestland groups showing formations and timelines within the overall regressive-to-transgressive mega sequence. [1]

The depositional sub-environments of the five Brent reservoirs are summarized in figure 3 and figure 4,

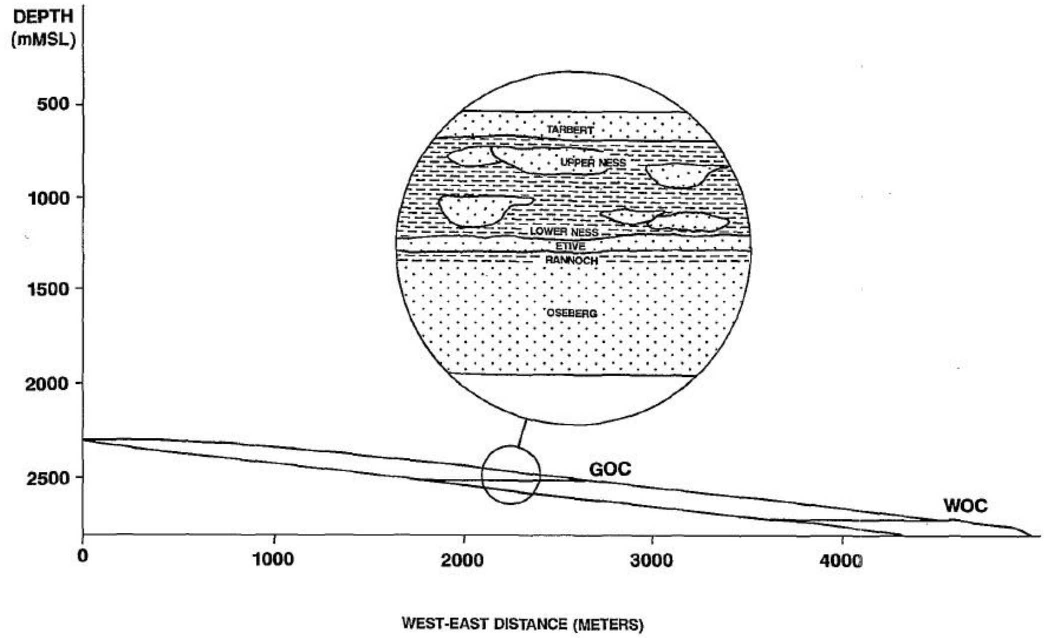

Figure 3: Oseberg reservoir zones [3]

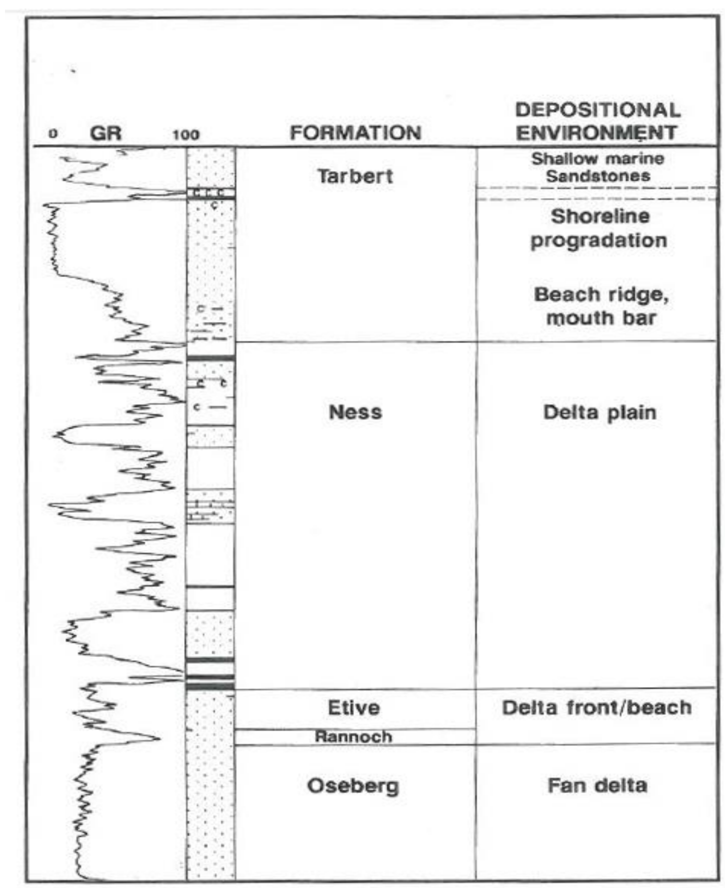

Figure 4: Stratigraphy and depositional environment of the Brent Formations [2]

The predominant part of the reserves is located in the Oseberg, Rannoch and Etive Formations, which in general are rather homogeneous sands with very good reservoir properties.

The Oseberg Formation:

The Oseberg formation (Upper Toarcian to Lower Bajocian), is considered to be the most important geologic unit for development of the Oseberg field, because it contains the most of recoverable oil.

The Oseberg Formation (Upper Toarcian to Lower Bajocian) consists of relatively homogenous coarse grained sandstones defined from the Oseberg Field (block 30/6) between the Viking Graben and the Horda Platform. The base of the formation is shales of the Dunlin Group and the upper boundary is the micaceous sandstones of the Rannoch Fm. The formation has been correlated with various formations of the Brent Group, but whereas the Brent Group forms a deltaic unit building out from the south, the Oseberg Formation has its source area to the east. The sandstones in the lower part are deposited in a shallow marine environment, overlain by alluvial sands and capped by sand reworked by waves. The thickness in the type area is between 20-60 m. The average porosity is about 24% and the permeability ranges from 1-3.5 Darcy. The highly permeable formation has good reservoir communication, as demonstrated by its production history. [5]

Rannoch Formation:

The Rannoch Formation (Upper Toarcian to Bajocian) in the type area is well-sorted very micaceous sandstones, showing a coarsening upwards motif, deposited as delta front or shore face sands. The upper boundary is defined by cleaner sandstones of the overlying Etive Formation. The thickness of the Rannoch Formation in the type area varies between 35m and 63m.

The Etive Formation:

The Etive Formation (Bajocian) contains less micaceous sandstones than the underlying Rannoch Formation. The upper boundary is the first significant shale or coal of the overlying Ness Formation. The depositional environment for the Etive Formation is interpreted as upper shore face, barrier bar, mouth bar and channel deposits. The thickness of the formation varies appx. from 11 m to more than 50 m.

The Ness Formation

The ness formation (Bajocian to Bathonian), has a low recovery due to the complex reservoir geometry of its formation. The Ness formation consists of the complex reservoir geometry of fluvial and fluvial related sandstones interbedded with coals and shales. Characteristic features are numerous rootlet horizons and a high carbonaceous content. The upper boundary is the change to the more massive and cleaner sandstones of the overlying Tarbert Formation. The reservoir complexity is illustrated by figure 5, which is a schematic north-south cross section of the Alpha structure.

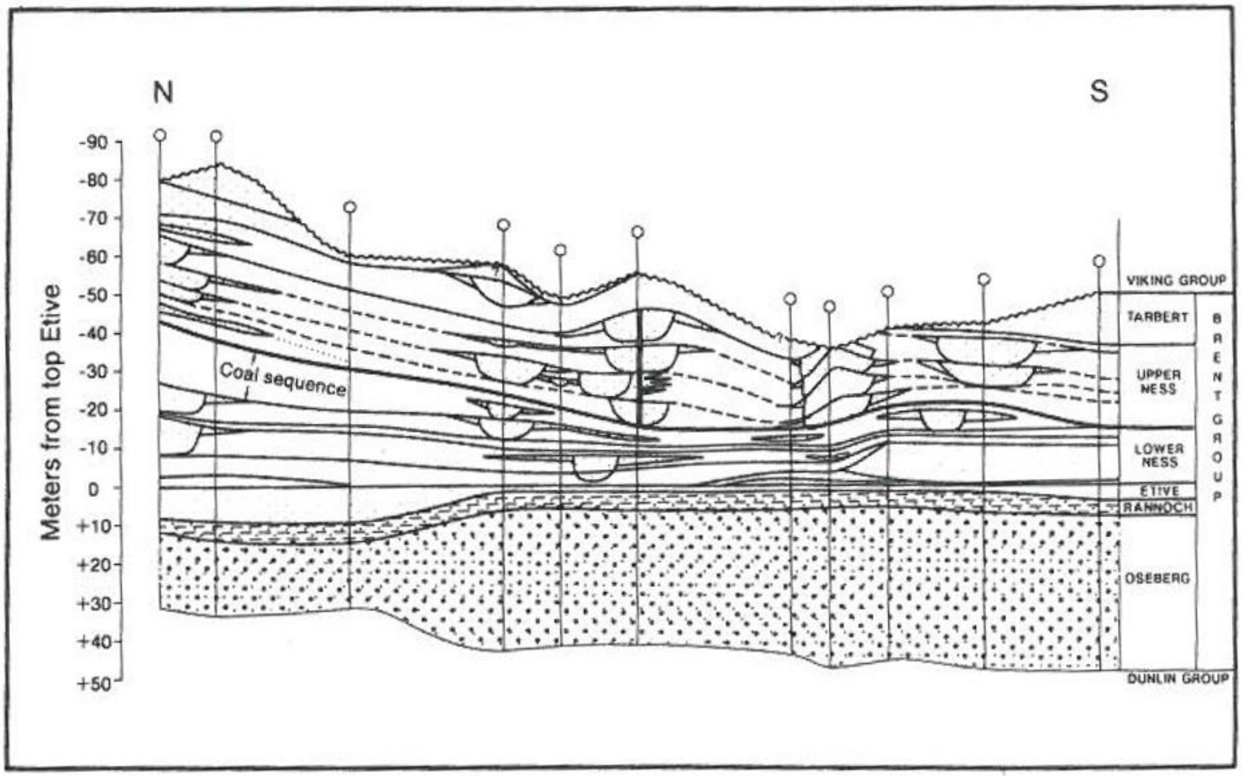

Figure 5: Schematic north-south profile of the Alpha Structure, illustrating some of the reservoir complexity of the Ness formation. [2]

The complexity of this formation is also illustrated by the observations of different oil-water contacts within Ness formation on two of the structures that constitute the Oseberg field. The formation is interpreted to represent delta plain or coastal plain deposition. The amount of silt and mudstones in the formation may act as a local seal. The Ness Formation shows large thickness variations ranging from 26 m up to about 140 m. The permeability is typically 0.40 to 3 Darcy. The Ness formation is subdivided into Upper Ness and Lower Ness formation.

The Tarbert Formation

The Tarbert formation (Bajocian to Bathonian), which is present in both the southern and northern parts of the field, is a sheet sand reservoir. In the Northern part of the field, it is an important reservoir with excellent properties, exhibiting sand thickness up to 42 m, porosities as high as 25%, and permeability up to 4 Darcy.

The present distribution of the Tarbert sands, which are absent in the crestal and central parts of the field, is a result of relationship between deposition and erosion. Given this reservoir distribution, the importance of the Tarbert reservoir in the North was fully realized during the predrilling of the production wells. It then became evident that locally this reservoir was more important than the Oseberg Formation, which had been the main target for the exploration and appraisal drilling.

2.2 Reserves

Oseberg Main:

The reserves of Oseberg Main have been given below in table 2,

Table 2: The NPD estimate for reserves and oil in place volumes (Norwegian share) [6]:

Initial Reserves:

Orig. in place oil [mill Sm^3]	Orig. in place ass. liquid [mill Sm^3]	Orig. in place ass. gas [bill Sm^3]	Orig. in place free gas [bill Sm^3]
638.00	**28.70**	**93.00**	**121.80**

Recoverable Reserves:

Orig. recoverable oil [mill Sm^3]	Orig. recoverable gas [bill Sm^3]	Orig. recoverable NGL [mill ton]	Orig. recoverable oil eq. [mill Sm^3 o.eq.]
401.70	**122.50**	**12.80**	**548.52**

Remaining Reserves (Until: 31. 12. 2015)**:**

Remaining oil [mill Sm^3]	Remaining gas [bill Sm^3]	Remaining NGL [mill ton]	Remaining oil eq. [mill Sm^3 o.eq.]
31.00	**79.30**	**3.50**	**116.95**

Production from Oseberg Main has contributions from the Brent Group formations, Statfjord formations and the Cook formation. Among all the formations, the majority of the hydrocarbons are located in the Brent group, while the rest of the hydrocarbons are producing from Statfjord, Cook, and Shetland chalk formations. In addition to the Alpha and Gamma fault blocks, Oseberg Main also comprises the subsea satellites Vestflanken (Statfjord Formation) and Delta (Tarbert Formation).

2.3 Drainage Strategy

Oseberg Main:

Oseberg oil field is located on the outer edge of the Viking Graben. It is divided into a number of structures, consisting several reservoirs in the Brent group of middle Jurassic age. The main reservoir lies in the Oseberg and Tarbert formations, but Etive and Ness formations also showed good reservoir properties. The field has been produced with pressure maintenance through gas, water and water alternating gas (WAG) injection [7].

At the beginning of production in 1 December 1988, the initial reservoir pressure of the Main Brent reservoir was 294 bar (4264.11 psi) at 2700 m TVD MSL. Considering lifting capacity of the wells and the total field recovery, it was decided to go for gas and/or water injection for the pressure maintenance of the reservoir. In the simulation studies, gas injection gave a higher recovery than water flooding, but as the amount of dissolved gas from the oil production only contributed about 40% of the volume needed for full pressure maintenance, water injection was decided to make up for the remaining 60% at the beginning of production [8]. In 1986, it was decided to use imported gas from another field as the main drive mechanism. In 1991, when gas import starts from Troll (TOGI), the pressure in the main reservoirs was depleted by approximately 28 bars. Later, in the period with high TOGI import (1991-1996) the pressure was kept at a fairly constant level. Massive gas injection high up in the structure, has resulted in very good oil displacement and the formation of a large gas cap. The plateau production of the Oseberg field ended in 1997, as less TOGI gas was imported, and although additional gas also was imported from Gamma North Statfjord, the pressure started to decline again. From 1991 to 2002 an amount of 21.7 billion standard cubic meters of Troll gas were injected into Oseberg. The initially the Troll gas was estimated to increasing the Oseberg oil production by 65-125 million barrels. The gas export from OFC started in September 2000. Since, 2002, the gas injection is continued with the produced gas from the Oseberg field [9].

Chapter 3

3.1 General Theory on oil recovery methods

Oil recovery operations traditionally have been subdivided into three stages: primary, secondary and tertiary methods. [10]

Primary recovery, the initial recovery stage, refers to the recovery resulted from the displacement energy naturally existing in a reservoir. In this case, the oil is pushed from the pore spaces into the wellbore through the natural reservoir pressure or gravity drive; combined with artificial lift techniques (such as pumps) which bring the oil to the surface [11]. The natural driving mechanisms that provide the energy for recovery from the oil reservoirs are solution gas, water influx, and gas cap drives, or gravity drainage etc. [12]. When the natural energy of the reservoir is no longer sufficient to sustain the production rates, artificial means of injecting energy (i.e. secondary/tertiary method) into the reservoir are introduced.

Secondary recovery, is the recovery technique, used to augment the natural energy of the reservoir by artificially injecting fluid (gas or water) into the reservoir to force the oil to flow into the wellbore and to the surface [13]. The main objective of the secondary recovery is to enhance the sweep efficiency of oil towards the production wells to increase the productivity of oil. Another major use of secondary recovery is to restore and maintain reservoir pressure, which normally declines during the primary recovery phase. Due to its capital intensive nature, secondary recovery should only be employed when primary recovery is no longer economically viable to recover the oil [14].

Tertiary recovery (Enhanced oil recovery), any technique applied after secondary recovery, is a sophisticated recovery technique that is applied to increase or boost the flow of fluid within the reservoir. It involves the injection of fluid other than just conventional water and immiscible gas into the reservoir in order to effectively increase oil production [15]. These methods go beyond primary and secondary recovery by reducing the viscosity of the fluid and increasing the mobility of the oil. Tertiary recovery is normally applied to recover more of the residual oil remaining in the reservoir after both primary and secondary recoveries have reached their economic limit.

Figure 6, illustrates the different oil recovery stages and the corresponding oil recovery.

3.2 Pressure Maintenance:

Pressure maintenance is a secondary recovery process that is implemented early during the primary producing phase before reservoir energy has been depleted. Pressure maintenance projects, which can be accomplished by the injection of either gas or water, will almost always recover more oil reserves than are recoverable by primary producing mechanisms. [17]

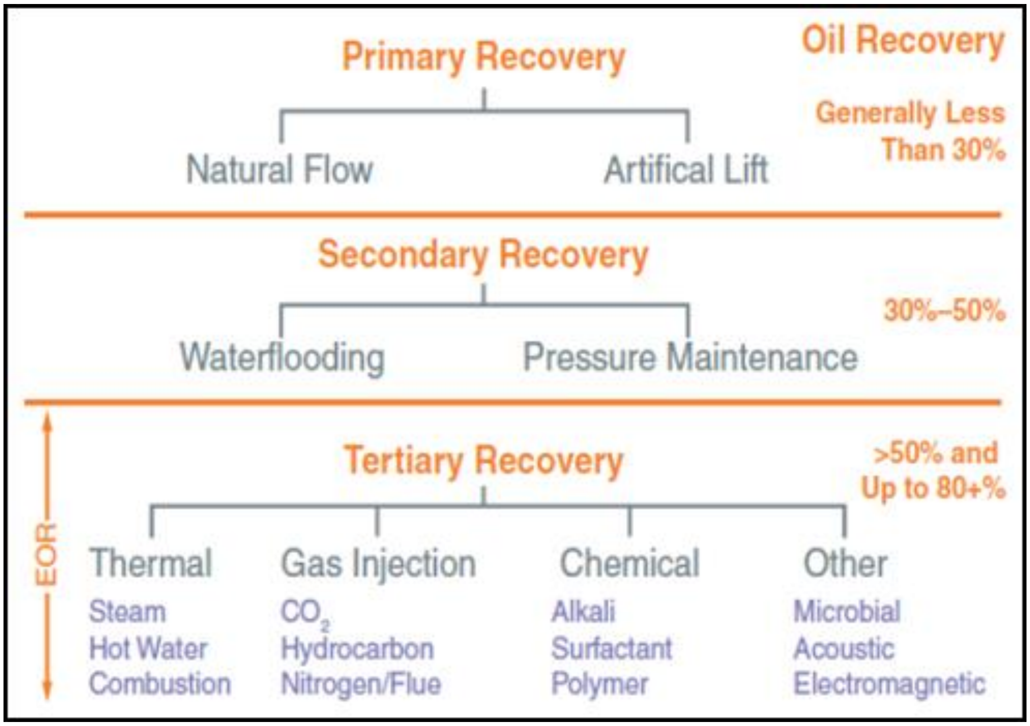

Figure 6: The different oil recovery stages and the corresponding oil recovery [16]

3.2.1 Gas Injection/Flooding

Both natural gas and air have been used in gas injection projects, and in some cases nitrogen and flue gases have been injected. Although the ultimate oil recovered from gas injection (immiscible) projects will normally be lower than for water flooding, gas injection may be the only alternative for secondary recovery under certain circumstances-

- If permeability is very low, the rate of water injection may be so low that gas injection is preferred.
- In reservoirs with swelling clays, gas injection may be preferable.
- In steeply-dipping reservoirs, gas that is injected updip can very efficiently displace crude oil by a gravity drainage mechanism; this technique is very effective in low-permeability formations such as fractured shales.
- In thick formations with little dip, injected gas (because of its lower density) will tend to override and result in vertical segregation if the vertical permeability is more than about 200md.
- In thin formations especially if primary oil production has been by solution-gas drive, gas may be injected into a number of wells in the reservoir on a well pattern basis; this dispersed gas injection operation attempts to bank the oil in a frontal displacement mechanism.
- In addition to the external gas injection into reservoirs with dip as just described (which may be into a primary or secondary gas cap), a variation called attic oil recovery involves injection of gas into a lower structural position. If there is sufficient vertical permeability, the injected gas will migrate upward to create a secondary gas cap that can displace the oil downward where it is recovered in wells that are already drilled. [17]

According to Thomas et al. [18] the parameters, that should be considered as gas injection criteria, are- Phase behavior, Interfacial tension (IFT), Mobility effects, Pore size distribution, Gravity, Wettability.

Gas flooding classification

Gas flooding can be either immiscible or miscible. The injection of hydrocarbon gas may result in either a miscible or immiscible process. The key factors that determine whether a gas flooding process is immiscible or miscible are- reservoir pressure, reservoir temperature, composition of injection gas, composition of reservoir fluid, and reservoir heterogeneities such as faults and permeability barriers. The impact of each factor can be determined with laboratory measurements and modeling of the displacement process. [19]

3.2.2 Miscible gas injection

In miscible flooding, the incremental oil recovery is obtained by one of the three mechanisms; oil displacement by solvent through the generation of miscibility (i.e. zero interfacial tension between oil and solvent – hence infinite capillary number), oil swelling, and reduction in oil viscosity [20]

The EOR screening criteria for miscible gas injection processes are presented in table 3. The injection gases are nitrogen/flue gas, hydrocarbon gas, and carbon dioxide.

Table 3: EOR Screening Criteria for Miscible Gas Injection Processes [19]

Gas Injection Process (miscible)	Fluid Properties			Reservoir Properties				
	Gravity (°API)	Viscosity (cp)	Temp. (°F)	Porosity (%)	Perm. (md)	Oil Sat. at start (% PV)	Lithology	Depth (ft)
Nitrogen/ flue gas	>30	<0.5	>250	>10	>30	>50	Carbonate/ Sandstone	> 7000
Hydrocarbon Gas (HC)	21–57	0.1–1.3	136–290	4–26	10–5000	30–98	Carbonate/ Sandstone	4000– 14500
Carbon Dioxide (CO_2)	28–44	0.4–3.0	100–250	4–26	2–500	25–90	Carbonate/ Sandstone	2000– 12000

3.2.3 Immiscible gas flooding

Immiscible displacement occurs in a displacement process where a distinct interface (or boundary) exists between the displaced fluid and the displacing fluid. This includes displacement processes that are described as near-miscible. Immiscible gas flooding is considered as the secondary recovery method as water flooding. The injection in immiscible gas flooding could be nitrogen, hydrocarbon gas, flue gas, carbon dioxide, or any other gas mixtures.

In immiscible gas injection, flooding by the gas is conducted below Minimum miscible pressure. This low pressure injection of gas is used to maintain reservoir pressure to prevent production cut-off and thereby increase the rate of production. [20] In Oseberg Main the main drive mechanism has been the immiscible, gravity stable gas displacement which provide very low residual oil saturation in the gas swept zones. [21]. Gas injection process in Oseberg Main have been illustrated in figure 7,

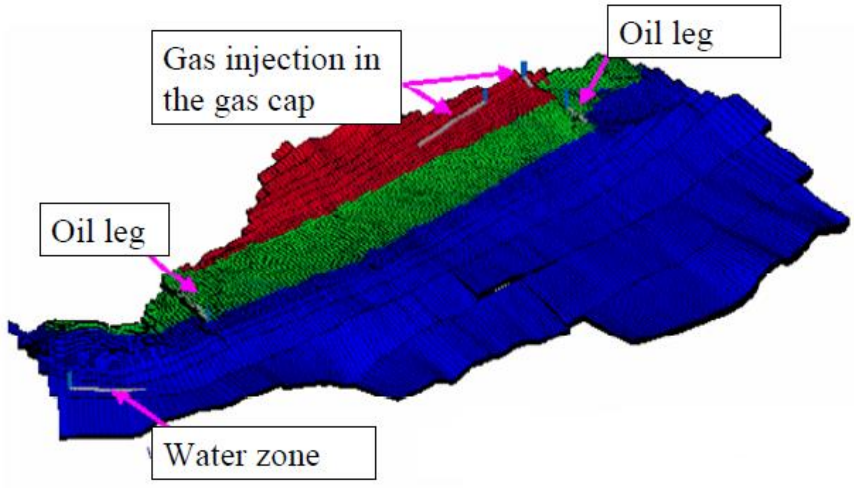

Figure 7: Gas injection process in Oseberg main field.

3.3 Locate the remaining oil (LTRO)

The aim of the locate the remaining oil is to identify the areas and reservoir layers containing potentially by-passed oil through detailed mapping and application of various reservoir modelling techniques.

The identification of remaining oil is primarily based on a concept of trap types which cause bypassing and sub-optimal drainage in the field. Four basic types can be distinguished to locate the remaining oil. Fig: presents an illustration of the different LTRO trap types. [22]
LTRO types can be-
- Oil trapped under attic conditions at faults.
- Oil trapped in isolated fault blocks because of sand/shale juxtaposition.
- Oil trapped in sedimentary bodies like channel sand lenses
- Oil left in oil rims which move too slowly to existing offtake points to be efficiently drained before depressurization
- Oil left behind as a result of a sub-optimal drainage pattern and resulting wedge shaped flood fronts.

Figure 8, illustrates the different LTRO types.

However, often, oil trapped under such conditions is not targeted when production wells are drilled because the volumes are small and their presence is uncertain. Experience has shown that oil is left in combinations of the above trap types or trapping conditions and that a given trap type is valid for some layers but rarely for the entire reservoir section. It is the task of the geologists to identify these “traps’” beyond the resolution of dynamic modelling. Once there is a geological ‘hint’ or even a concept of an unswept area, further detailed, analysis focusing on these areas can be progressed.
As the flood fronts approach the crest, oil is left in various types of traps and can be produced only by specially targeted wells. The full field model (FFM) generally has too coarse scale to pinpoint these small accumulations, and identification is by detailed study with a high-resolution geological model (SGM) in conjunction with analysis of individual-well performances.

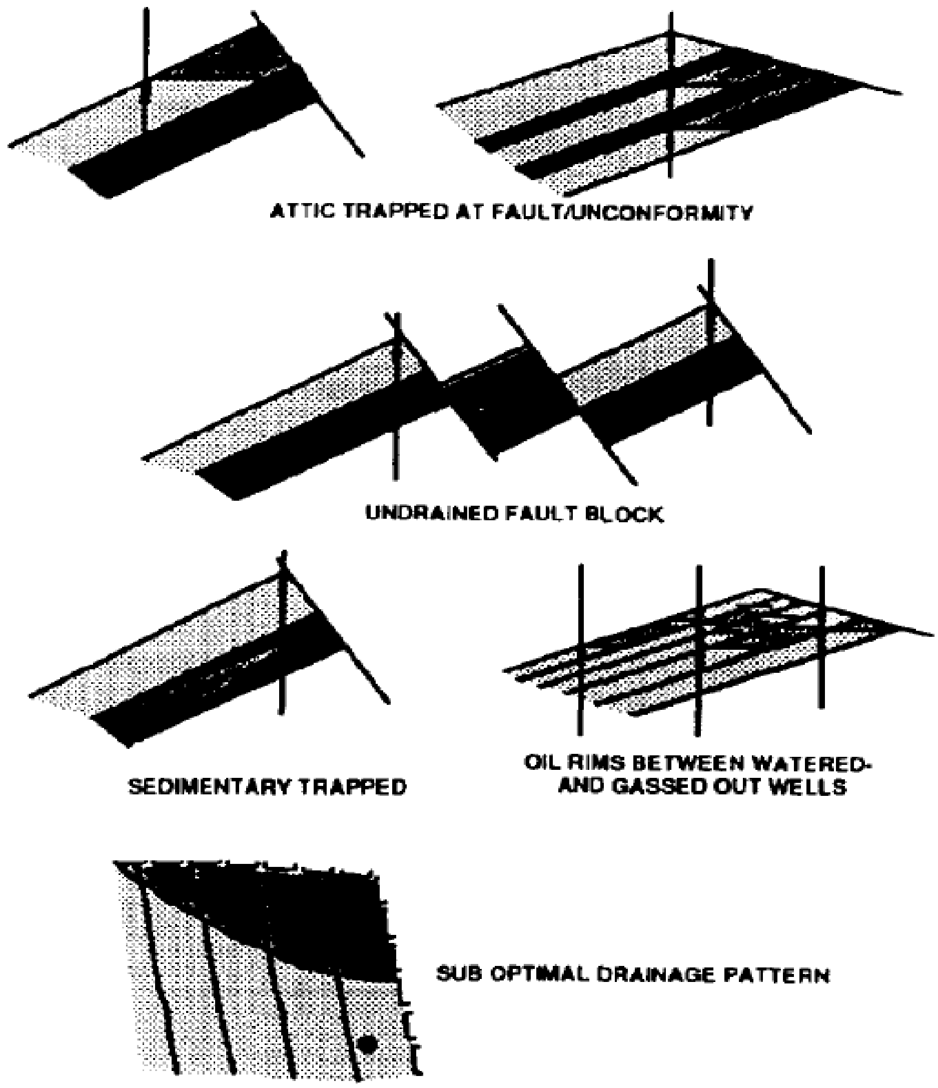

Figure 8: LTRO trap types *[22]*

3.4 Gas Blowdown Phase

Gas Cap Blowdown (GCBD), also referred to as "Reservoir depressurization", is a process of depressurizing a reservoir for further hydrocarbon recovery (i.e. gas), is often considered as a late life recovery mechanism. Conventional blowdown is usually conducted in oil reservoirs with gas caps. The reservoir depressurization is applied to extract the gas available in the gas cap of a reservoir after full extraction of the oil reserves. During the main life of these fields, the gas cap is not produced. The objective is to maximize oil production and conserve reservoir energy. Water, gas or Water altering gas (WAG) injection may be used to maintain reservoir pressure. When the remaining oil volume can't be economically extracted, the pressure energy preserved in the gas cap is no longer required. The blowdown is implemented by perforating and producing wells in the gas cap. The result is a rapid reduction of pressure in the reservoir and production of gas. Associated gas cap liquids are also produced. Aquifer influx during the blowdown process may result in additional recovery from the oil rim. Hence, it can be allowed to deplete or depressurize and in the process gas can be produced for sales or other applications.

Chapter 4

4.1 Simulation Study

This chapter will shortly explain about the eclipse simulator and the properties of the Beta Brent simulation model.

4.2 The Eclipse Simulator

The Eclipse 100 simulator [23] is considered to be one of the leading reservoir simulator in oil industry, which offers the industry's most complete and robust set of numerical solutions for fast and accurate prediction of dynamic behavior for all types of reservoirs and development schemes.

A simulation study requires description of the reservoir's rock and fluid properties, validation of completion and production history, and extensive history matching to validate and modify this input data. As an input, user creates a text (data) file; contains particular sections with a set of keywords, which provides a complete description of a specific reservoir. The following section describes shortly about the model built for the Beta Brent reservoir. Reservoir simulation is very important to generate reliable forecasting of production/injection phenomena and correct predictions for field recovery potential. However, during the initial field development phase, the amount of available information, as an input, for the reservoir can't be well defined and it is very difficult to obtain a correct reservoir model. Therefore, the use of simplified simulation models provides more understandable results.

4.3 The Beta Brent Reservoir Model

In this study, an anonymous segment named as Beta Brent reservoir has been considered, which has the average analogous properties of a typical Brent reservoir. Figure 9, illustrates the Beta Brent reservoir simulation model.

4.3.1 Simulation grids

The Main characteristics of the simulation model used in this study:

- Total active blocks used: 77015
- Typical DX x DY: 75 x 115.
- Sum of Brent Layers: 55 (Tarbert: 11; Lower Ness: 11; Upper Ness: 6; ORE: 27)
- The dimensions of the simulation grid: 121 x 219x 55 cells (x-y-z dimensions)

4.3.2 Reservoir Properties

In this simulation model, the property models are from the three independent geo-models. The property modelling in these geo-models consisted of three steps: 1) blocking of wells, 2) facies modelling, and 3) porosity and permeability modelling.

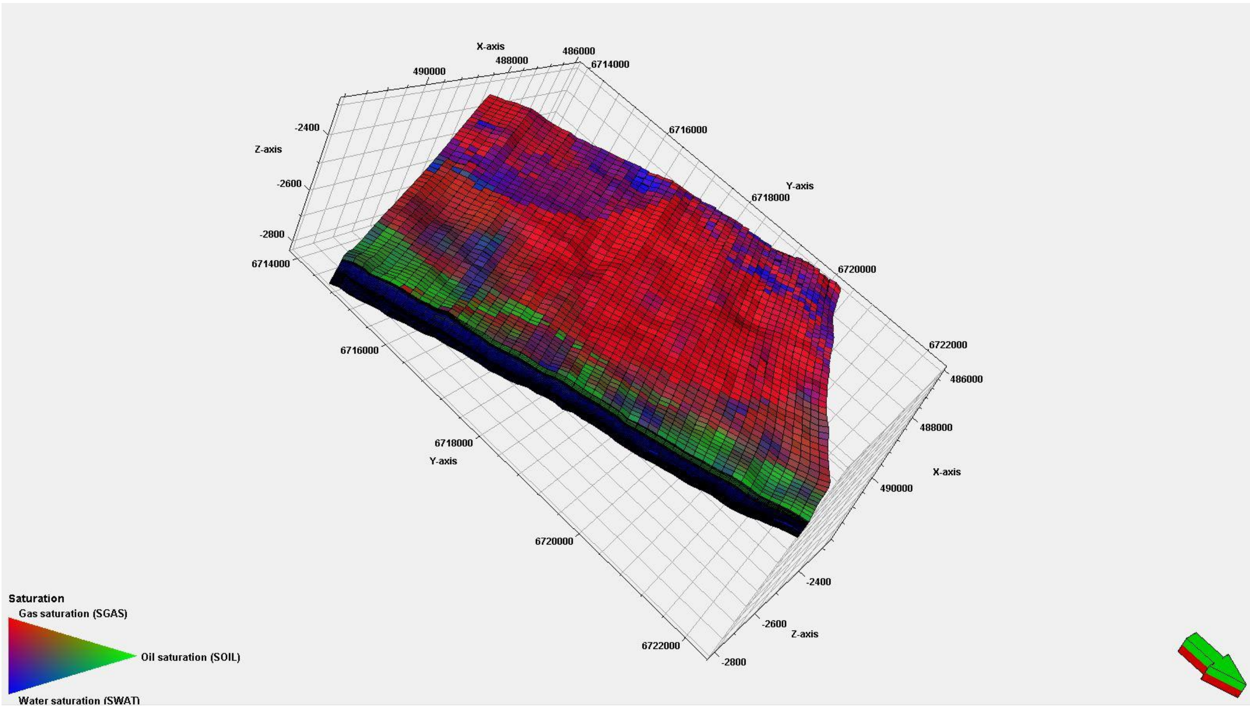

Figure 9: The Beta Brent reservoir simulation model

4.3.3 Reservoir Zonation

The simulation grid zones and layers have been given below in table 4,

Table 4: Reservoir zonation for Beta Brent reservoir (simulation grid)

Formation		Zone	Formation	No. of upscaling Layers	Simulation Layers
Upper Brent	Tarbert	1	Upper Tarbert	3	1-3
		2	Mid Tarbert	3	4-6
		3	Lower Tarbert	5	7-11
	Ness	4	Upper Ness 2	1	12-12
		5	Upper Ness 1	5	13-17
Lower Brent		6	Lower Ness 3	5	18-22
		7	Lower Ness 2	5	23-27
		8	Lower Ness 1	1	28-28
	ORE	9	Etive- Rannoch	6	29-34
		10	Oseberg 4	1	35-35
		11	Oseberg 3	12	36-47
		12	Oseberg 2	4	48-51
		13	Oseberg 1	4	52-55

4.3.4 Porosity & Permeability

The reservoir characterization required to define the porosity and the permeability for each grid block in a reservoir simulation model is a very rigorous, time consuming and at the same time more loosely defined than reservoir characterization required in detailed development of geological studies. The 2D porosity maps generated in Petrel 2015 has been used to find the porosities and permeabilities in different formations/layers in the reservoir simulation model. Table 5, shows the mean value of porosity for Tarbert, Ness and ORE in Beta Brent Reservoir

Table 5: The mean value of porosity for Tarbert, Ness and ORE in Beta Brent Reservoir

Formation	Simulation Layer	Mean Value	Remark
Tarbert	1-11	0.1913	Due to some heterogeneity, reservoir properties in upscaling doesn't match perfectly with geo-model.
Ness	12-28	0.1257	Due to heterogeneity, reservoir properties in upscaling doesn't match nicely with geo-model.
ORE	29-55	0.2145	Due to homogeneity, reservoir properties in upscaling matches nicely with geo-model.

The Upscaling simulation grid results of porosity in Beta Brent different formations are given below in figure 10,

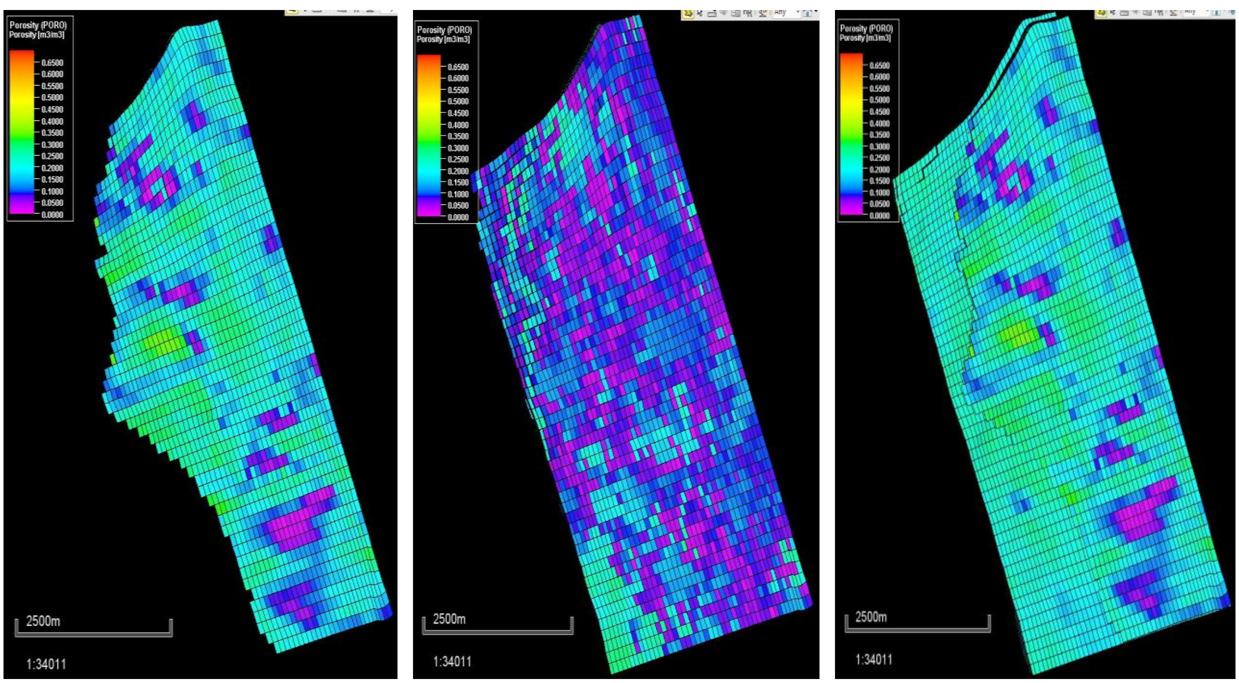

Figure 10: 2D map of Porosity model upscaling for Beta Brent Formations (Simulation grid); left- Tarbert, middle- Ness, right- ORE

Table 6, shows the mean value of permeability (x,y,z) for Tarbert, Ness and ORE(Oseberg, Rannoch, Etive) in Beta Brent reservoir.

Table 6: The mean value of permeability (x,y,z) for Tarbert, Ness and ORE(Oseberg, Rannoch, Etive) in Beta Brent reservoir

Formation	Simulation Layer	Mean Value			Remark
		x (md)	y (md)	z (md)	
Tarbert	1-11	2201.93	4620.06	789.14	Due to some heterogeneity, reservoir properties in upscaling doesn't match perfectly with geo-model.
Ness	12-28	456.57	1184.58	81.78	Due to heterogeneity, reservoir properties in upscaling doesn't match nicely with geo-model.
ORE	29-55	2570.32	5621.91	1045.83	Due to homogeneity, reservoir properties in upscaling matches nicely with geo-model.

Upscaling simulation grid of permeability in Beta Brent different formations are given below in figure 11,

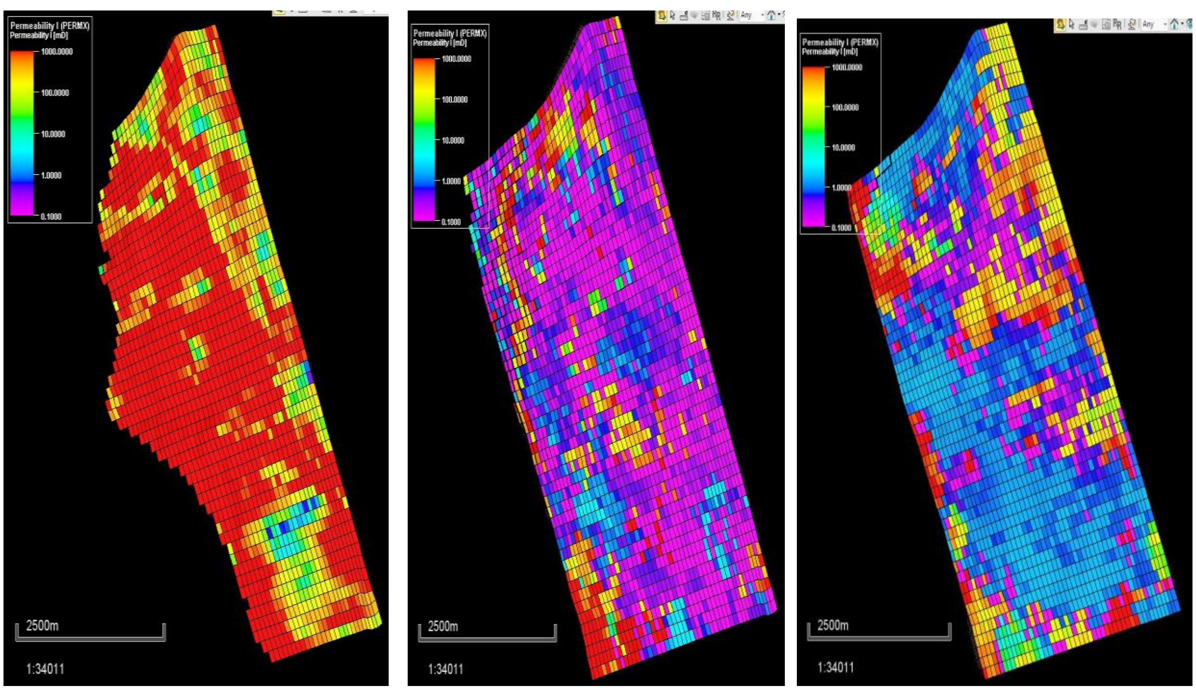

Figure 11: 2D map of permeability I (PERMX) model upscaling for Beta Brent Formations (Simulation grid); left- Tarbert, middle- Ness, right- ORE

The 2D map of permeability J (PERMY) model upscaling for Beta Brent Formations (Simulation grid) have been illustrated in figure 12,

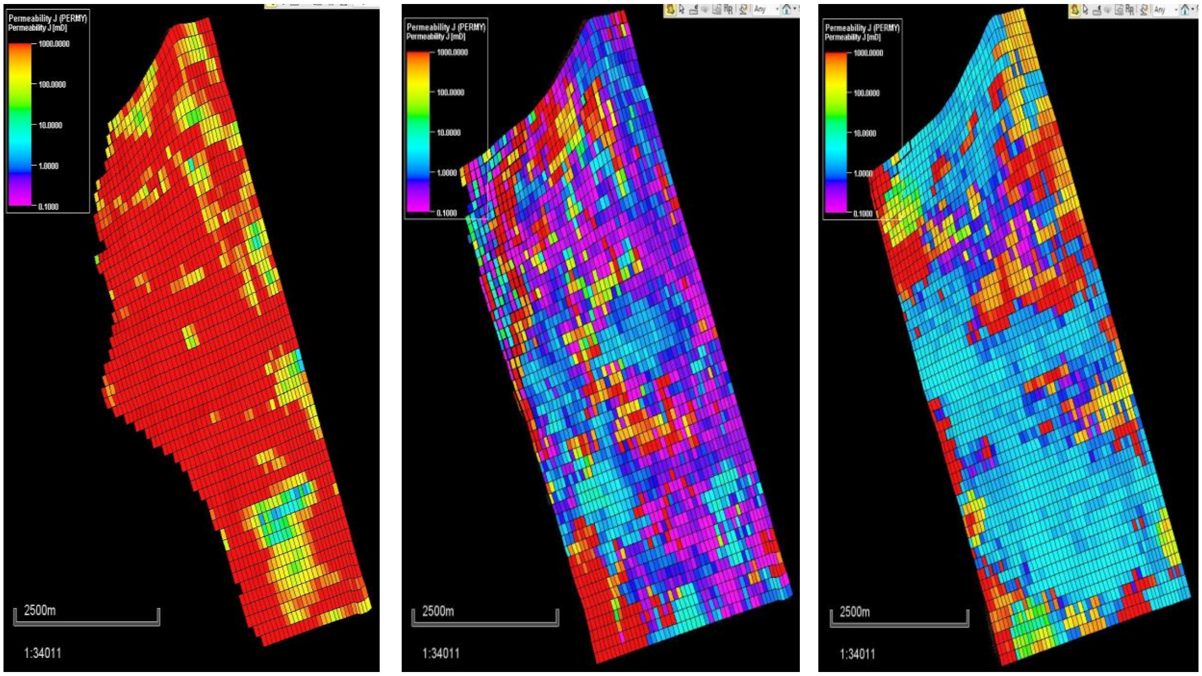

Figure 12: 2D map of permeability J (PERMY) model upscaling for Beta Brent Formations (Simulation grid); left- Tarbert, middle- Ness, right- ORE

The 2D map of permeability k (PERMZ) model upscaling for Beta Brent Formations (Simulation grid) have been illustrated in in figure 13,

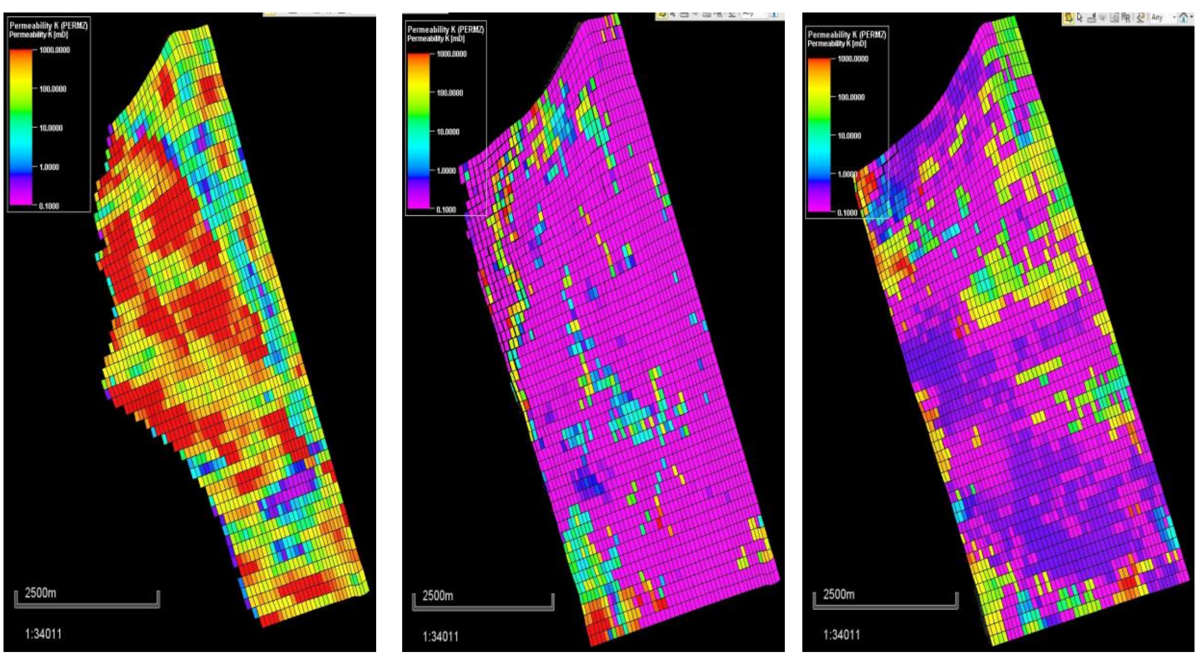

Figure 13: 2D map of permeability k (PERMZ) model upscaling for Beta Brent Formations (Simulation grid); left- Tarbert, middle- Ness, right- ORE

4.3.5 Net to Gross

The map of net-to gross sand for each reservoir zone in the geological model can be used in the reservoir simulation model. However, Net to gross ratio is not used in this model because it's been considered that the effective porosity was generated in the geo-models.

4.3.6 Fluid Properties

The fluid properties that has been considered for the Beta Brent reservoir are given below in table 7,

Table 7: Fluid properties of Beta Brent reservoir [24]

Bubble point pressure, P_b (bar)	281
Solution gas oil ratio, (Sm^3/Sm^3)	145
Oil density, ρ_o (g/cm^3)	850
Oil viscosity (cp)	0.43
Gas viscosity (cp)	0.023
Oil formation volume factor at (Rm^3/Sm^3)	1.43
Gas formation volume factor, B_g (Rm^3/Rm^3)	222

4.3.7 The Rock Compressibility

The rock compressibility value used for the Beta Brent reservoir are given below:

- Upper Brent (Tarbert and Upper Ness) = $5*10^{-5}$/bar
- Lower Brent (Lower Ness 1-2, Oseberg, Etive and Rannoch) = $12*10^{-5}$/bar

4.3.8 The Aquifer

In the model, it's been assumed to have constant pressure support in the aquifer by utilizing two horizontal water injected wells with a constant rate of 550 sm^3/d.

4.4 Well Placement

The wells are completed in different formations depending on the drainage strategy. A total number of 28 wells (6 injectors and 21 producers) has been placed in different formations. The list of injection and production wells in Beta Brent reservoir history model are given in table 8 and table 9. Figure 14, illustrates the well placement in Beta Brent reservoir model.

Table 8: List of injection wells in Beta Brent reservoir history model.

Injector Wells		
Well Name	Wellbore Contents	Duration
INJ-1	Gas	1991-2016
INJ-2	Gas	1992-2016
INJ-4	Water	1991-2016
INJ-5	Water	1991-2016
INJ-6	Gas	1991-2016

Table 9: List of production wells in Beta Brent reservoir history model.

Producer Wells				
Well Name	Wellbore Content	Group name	Duration	Cumulative oil Production (until Feb 2016) (sm^3)
P-1	Oil	BETA_OMIX	1991-1995	5.17×10^6
P-2	Oil	BETA _OMIX	1991-1995	4.59×10^6
P-3	Oil	BETA _ORE	1991-1995	4.50×10^6
P-4	Oil	BETA _NETA	1992-2001	8.80×10^6
P-5	Oil	BETA _NETA	1992-2001	5.10×10^6
P-6	Oil	BETA _ORE	1993-2002	5.04×10^6
P-7	Oil	BETA _ORE	1994-2010	9.10×10^6
P-8	Oil	BETA _NETA	1994-2015	3.80×10^6
P-9	Oil	BETA _NETA	1995-2016	6.29×10^6
P-10	Oil	BETA _OMIX	1996-2005	1.78×10^6
P-11	Oil	BETA _OMIX	1996-2016	4.76×10^6
P-12	Oil	BETA_OMIX	1997-2016	7.09×10^6
P-13	Oil	BETA _NETA	2001-2011	1.24×10^6
P-14	Oil	BETA _NETA	2001-2016	1.35×10^6
P-15	Oil	BETA _NETA	2002-2006	1.20×10^5
P-16	Oil	BETA _NETA	2005-2009	4.89×10^5
P-17	Oil	BETA _ORE	2007-2011	4.28×10^5
P-19	Oil	BETA _NETA	2011-2016	2.20×10^5
P-20	Oil	BETA _ORE	2013-2016	1.99×10^5
P-21	Oil	BETA _ORE	2015-2016	1.80×10^4

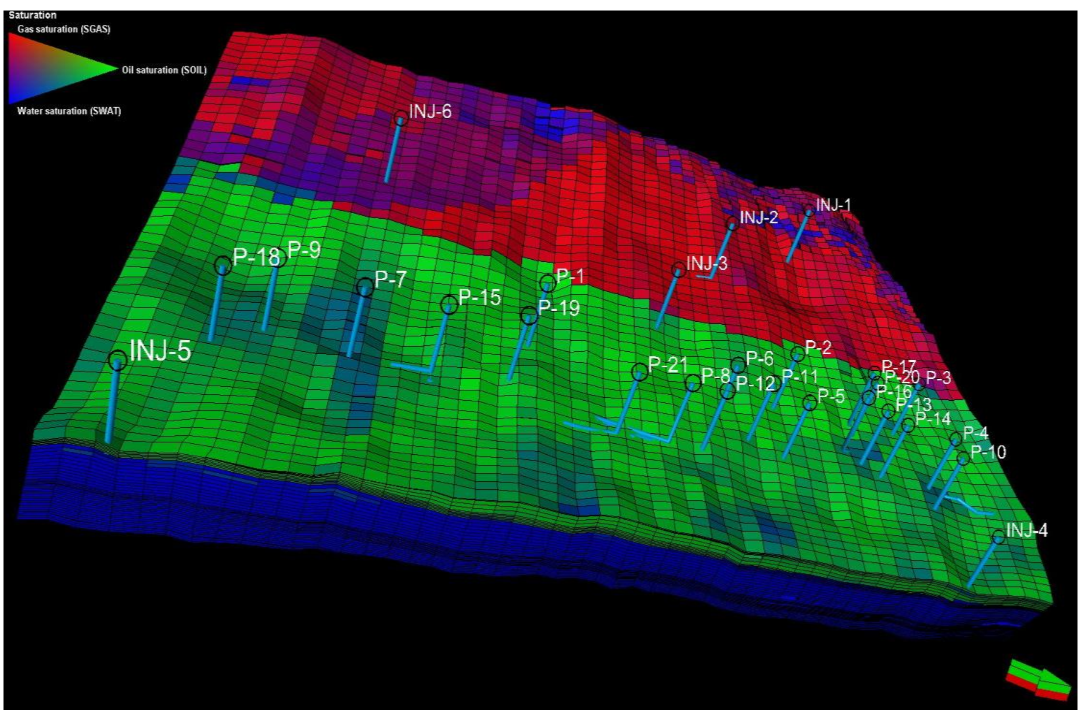

Figure 14: Well placement in Beta Brent reservoir

Chapter 5

5.1 Work Flow

The proposed work flow is the simulation run with the Eclipse 100 to generate the history model and the production forecast. The history model is simulated to obtain the production data from Feb 1991 to Feb 2016. Afterwards, a restart has been created to forecast the production of oil and gas until 2045.

5.2 Oil and gas in place

Beta Brent Reservoir

The oil and gas in place of Beta Brent reservoir have been given below in table 10,

Table 10: The estimate for oil and gas in place volumes in Beta Brent (generated in Petrel)

Initial oil and gas in place: (January, 1991)

Orig. oil in place [mill Sm^3]	Orig. gas in place [bill Sm^3]	Orig. in place free gas [bill Sm^3]
122.65	**36.82**	**20.178**

Remaining oil and gas in place (February, 2016)

Remaining oil in place [mill Sm^3]	Remaining gas in place [bill Sm^3]	Remaining free gas in place [bill Sm^3]	Remaining cond. [mill Sm^3]
51.80	**33.45**	**28.82**	**0.00**

5.3 Drainage strategy

Drainage strategy in history (1991-2016):

In the Beta Brent reservoir model, it has been assumed, this model has the same reservoir properties of a typical Brent reservoir. The initial reservoir pressure of the model is approximately 284 bar at 2700m and continuous pressure support in the aquifer has been implied by utilizing two water injection wells. The pressure maintenance of the field is mainly carried out by gas injection (imported gas) through gas injection wells until 2016. The pressure has been depleted about 106 bar from 1991-2016. The production history (1991-2016) of the Beta Brent reservoir model has been given in **Appendix B**.

Drainage strategy (2016-2045)

At first, the simulated results of current drainage strategy, defined as 'import case' (injection of gas), and the base case (i.e. gas export case- no injection of gas) has been simulated until 2045. From the simulated results, (discussed in chapter 6.3) it has been observed that, import case will not give significant amount of higher oil recovery than the base case. The desirable drainage strategy from 2016-2045, is to reach the similar oil recovery as the 'import case' while increasing the gas export.

As the goal is to get higher gas export, it is necessary to increase the gas export rate after sometime, instead of using a constant lower gas export rate. Therefore, in the base case, it has been assumed to have a lower gas export of 0.5 Bsm^3/year at the beginning, from 2016-2020 and higher gas export of 1 Bsm^3/year from 2020-2045. Three different cases with different constraints has also been considered to optimize the base case.

The import case, base case and the other base cases are given below-
Import case : Gas injection rate $2.5x10^6$ sm^3/d and oil production rate 20000 sm^3/d from 2016-2045. (no gas export)
Base case : Gas export 0.5 Bsm^3/year from 2016-2020 and gas export 1.0 Bsm^3/year from 2020-2045.
Base case_2: Gas export 1.0 Bsm^3/year from 2016-2020 and gas export 2.8 Bsm^3/year from 2020-2045.
Base case_3: Gas export 1.0 Bsm^3/year from 2016-2020 and gas export 3.5 Bsm^3/year from 2020-2045.
Base case_4: Gas export 0.5 Bsm^3/year from 2016-2020 and gas export 3.5 Bsm^3/year from 2020-2045.

Well Control:
Injection wells:
- In the data file, all the gas injection wells have been controlled by defining the group BETA_INJ in GRUPTREE keyword and closed down (no injection).
- The water injection wells remained same as before in the history model with a constant water injection of 550 sm^3/d.

Production wells:
- The active wells in the well groups have been controlled by defining the parent group BETA in GRUPTREE keyword.
- Lower limit of Bottom hole pressure 40 bar; Tubing head pressure 20 bar (for each well).

The list of the active producer wells is given below in table 11,

Table 11: Active producer wells after 2016 in Beta Brent reservoir

Well Name	Wellbore Content	Well type	Location of the well	Producing Formation
P-5	Oil	Vertical (deviated)	North-Eastern	Upper Ness, Tarbert
P-8	Oil	Horizontal	Northern	Upper Ness
P-9	Oil	Horizontal	Southern	Upper Ness, Tarbert
P-11	Oil	Horizontal (deviated)	North-Eastern	lower Ness, Etive and Rannoch
P-12	Oil	Horizontal	North-Eastern	Ness, Etive, Rannoch and Oseberg
P-14	Oil	Horizontal(deviated)	Northern	Upper Ness, Tarbert
P-15	Oil	Vertical (deviated)	South-Western	Upper and lower Ness
P-18	Oil	Horizontal (deviated)	Southern	Oseberg, Rannoch and Etive
P-19	Oil	Horizontal	South-Eastern	Lower Ness
P-20	Oil	Horizontal (deviated)	Northern	Oseberg, Rannoch and Etive
P-21	Oil	Horizontal(deviated)	South-Eastern	Oseberg, Rannoch and Etive

The well completion coordinates for all active producers have been given in **Appendix D**.

5.5 Production constraints for base cases

To generate the base cases, the following constraints in table 12 have been considered-

Table 12: The Production and injection constraints used for group control of BETA in different cases

	Feb 2016- Oct 2020					Oct 2020- Dec 2045				
Case	**Gas prod. Rate** MSm^3/d	**Gas sales rate** MSm^3/d	**Injec-tion rate** MSm^3/d	**Water inj. Rate (per well)** Sm^3/d	**Gas consu-mption rate** MSm^3/d	**Gas prod. Rate** MSm^3/d	**Gas sales rate** MSm^3/d	**Injec-tion rate** MSm^3/d	**Water inj. Rate (per well)** Sm^3/d	**Gas consu-mption rate** MSm^3/d
Base case	1.37	1.37	0	550	0	3.84	3.84	0	550	0
Base case_2	2.74	2.74	0	550	0	7.67	7.67	0	550	0
Base case_3	2.74	2.74	0	550	0	9.59	9.59	0	550	0
Base case_4	1.37	1.37	0	550	0	9.59	9.59	0	550	0

Some assumptions have been made while considering the production constraints-

- usually in gas export, the produced gas is sold, except the fuel and flare volumes. The amount of fuel and flare volumes depend on the field strategies. In this study, the fuel and flare volumes has not been counted.
- In case of the sensitivity analysis to optimize the base case, it is assumed to have large changes in the gas production rates for the different base cases. In a field case, gas processing facility often limits the gas production. It's not usually possible to vary the capacity much over time, unless there is modification to increase the production capacity, or a modification to decrease the first stage separation pressure to lower the gas production capacity.

5.6 Gas export scenarios

In the gas export scenarios, the effect of utilizing different duration of gas export rate on the fluid production performance has been observed. From the sensitivity analysis of the base cases, base case_3 (Scenario-1) has been chosen (explained in chapter 6.4.2) to be further studied with respect to different gas export scenarios. The different gas export scenarios have been defined in table 13,

Table 13: Different gas export scenarios in Beta Brent reservoir.

Scenario	Gas prod. Rate MSm³/d	Gas sales rate MSm³/d	Injec-tion rate MSm³/d	Water inj. Rate (per well) Sm³/d	Gas consu-mption rate MSm³/d	Gas prod. Rate MSm³/d	Gas sales rate MSm³/d	Injec-tion rate MSm³/d	Water inj. Rate (per well) Sm³/d	Gas consu-mption rate MSm³/d
Scenario-1 (Base case 3)	**Feb 2016- Oct 2020**					**Oct 2020- Dec 2045**				
	2.74	2.74	0	550	0	9.59	9.59	0	550	0
Scenario-2	**Feb 2016- Oct 2023**					**Oct 2023- Dec 2045**				
	2.74	2.74	0	550	0	9.59	9.59	0	550	0
Scenario-3	**Feb 2016- Oct 2026**					**Oct 2026- Dec 2045**				
	2.74	2.74	0	550	0	9.59	9.59	0	550	0
Scenario-4	**Feb 2016- Dec 2045**									
	9.59	9.59	0	550	0	-	-	-	-	-

Chapter 6

6.1 Results and discussion

In this chapter the results and analyses obtained from this thesis work is presented. Firstly, the 'history' has been simulated until 2016, which is the starting point for the gas export forecasts. To find an optimized base case several sensitivities have been run and analyzed. Finally, the results from the different gas export scenarios have been analyzed and presented. The simulation results show the production forecast of the reservoir from 2016-2045. The simulation results of the history (1991-2016) have been presented in **Appendix B**.

6.2 Locating the remaining oil in Beta Brent Reservoir

The produced and remaining liquid volumes in Beta Brent reservoir are presented in table 14,

Table 14: Produced and remaining liquid volumes in Beta Brent reservoir

Formation	Oil initially in place (Msm^3)	Produced Oil (Msm^3) Feb, 2016	Remaining OIP (Msm^3) Feb, 2016	Gas initially in place (Bsm^3)	Remaining GIP (Bsm^3) Feb, 2016	Recovery of oil (%) Feb, 2016
Tarbert	35.66	17.92	17.74	6.7	6.86	50.25
Ness	29.69	10.183	19.51	11.13	8.31	34.30
ORE	57.29	42.73	14.56	18.98	18.28	74.56
SUM	122.65	70.85	51.80	36.82	33.45	57.76

The observed values in table 14 showed that, the produced amount of oil in Tarbert, Ness and ORE are respectively 17.92 Msm^3, 10.183 Msm^3 and 42.73 Msm^3. Currently ORE has the highest degree of oil recovery (74.56%) followed by the Tarbert formation (50.25%). Ness formation has the lowest current recovery (34.30%) with respect to flooding. This is also reflected in the flooding maps of the Beta Brent reservoir (Fig 15). The remaining oil in place for Tarbert, Ness and ORE are 17.74 Msm^3, 19.51 Msm^3 and 14.56 Msm^3 respectively; which makes the total amount of oil in place 51.80 Msm^3. The remaining gas in place for Tarbert, Ness and ORE are 6.86 Bsm^3, 8.31 Bsm^3 and 18.28 Bsm^3 respectively. However, the fluvial and heterogeneous character of the Ness formation makes the mapping of remaining oil in Ness challenging. The remaining liquid volumes in Beta Brent per segment shows that, there are potential amount of oil left in the south-eastern and north-eastern part of the model. The oil saturation maps from the Beta Brent reservoir simulation model are given below in figure 15, in which the purple color reflects the non-reservoir part.

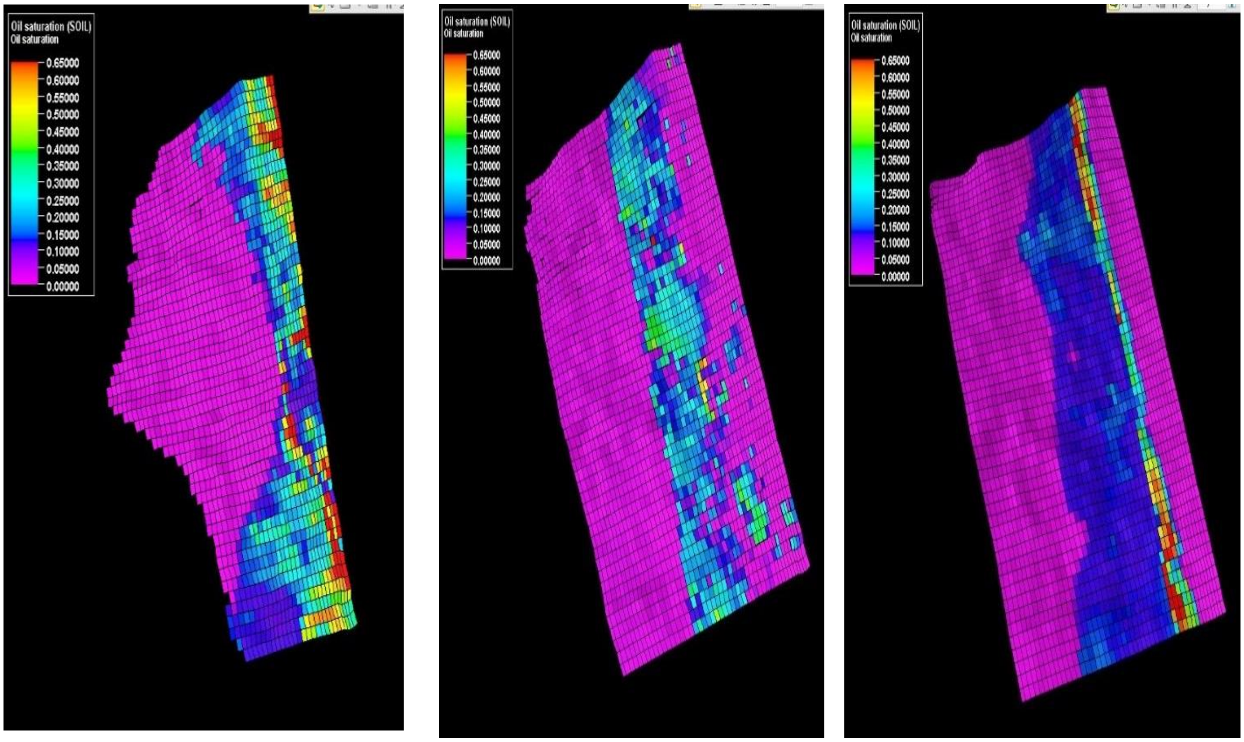

Figure 15: Average oil saturation map in 2016; left- Tarbert, middle- Ness, right- ORE

6.3 Prediction of the future field performance

The production profiles of the import case, no injection of gas case and the base case has been presented in **Appendix C**. The oil recovery efficiency of the import case and the base case is given below in figure 16,

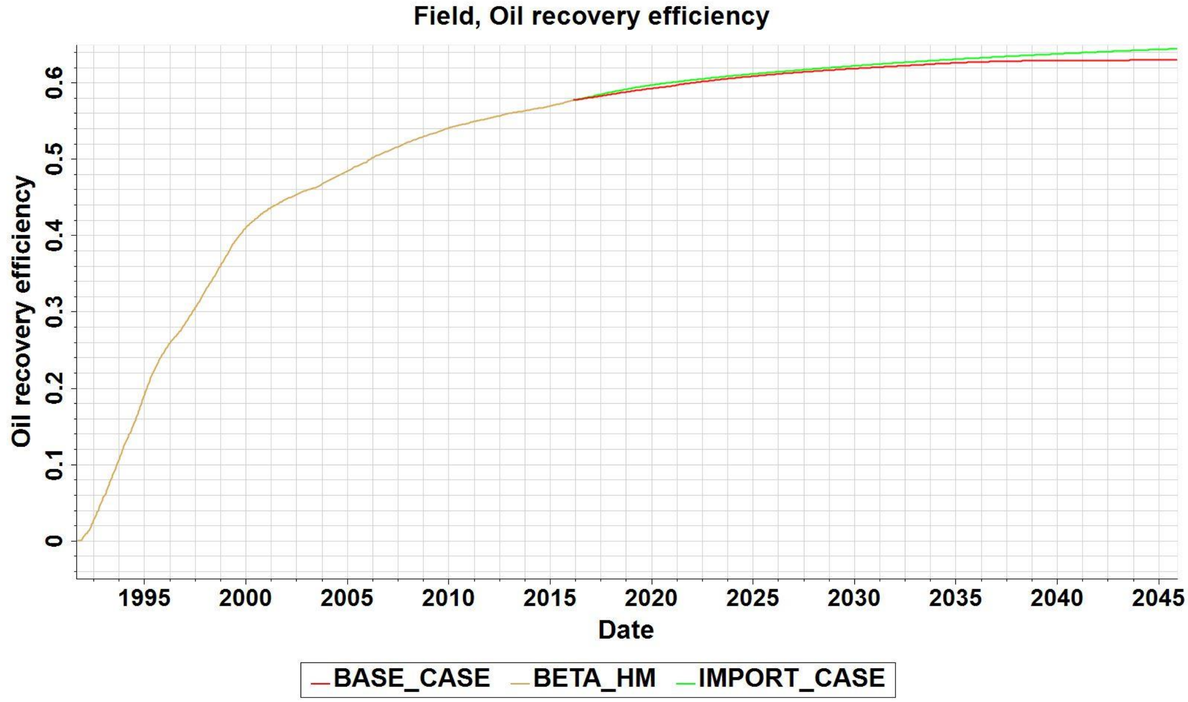

Figure 16: oil recovery efficiency for different drainage strategies

In figure 16, BETA_HM shows the history of oil recovery efficiency from 1991-2016(**Appendix B**); while the base case and the import case shows the simulated results from 2016-2045. From figure 16 and figure 35, it is seen that, the 'import case' will not give high oil recovery than the base case during 2016-2035. However, after 2035, the oil recovery for the import case increased more than the base case. Eventually, at the end of simulation in 2045, for 'import case', the oil recovery efficiency is 64.4 % (79.10 Msm^3); while, in the base case, the recovery of oil can be achieved to approximately 63.01% (77.29 Msm^3) in 2045. This is happening due to constraining the bottom hole pressure (40 bar) in each well, which allows further production of oil in the field (base case) until the field pressure reaches to approximately 40 bar (figure-37).

In a general sense we assumed that, injecting more gas may not be cost effective in terms of oil recovery for this small model. However, economical analysis should be taken into account for any field cases, whenever there are further chances of increasing the oil recovery. In this thesis, gas export has been studied as the drainage strategy.

In the following two sections, 6.4 and 6.5, the effect of utilizing different gas export rates and the effect of the duration of low gas export rates has been observed and analyzed.

6.4 Results from the sensitivity analysis of the base case

This sensitivity analysis reflects the effect of different gas export rates on fluid production performance. The production profiles and the discussion of the profiles of all four base cases are given below. The production profiles of the wells of each individual case have been presented in **Appendix E**.

6.4.1 Production profiles

Production rates:

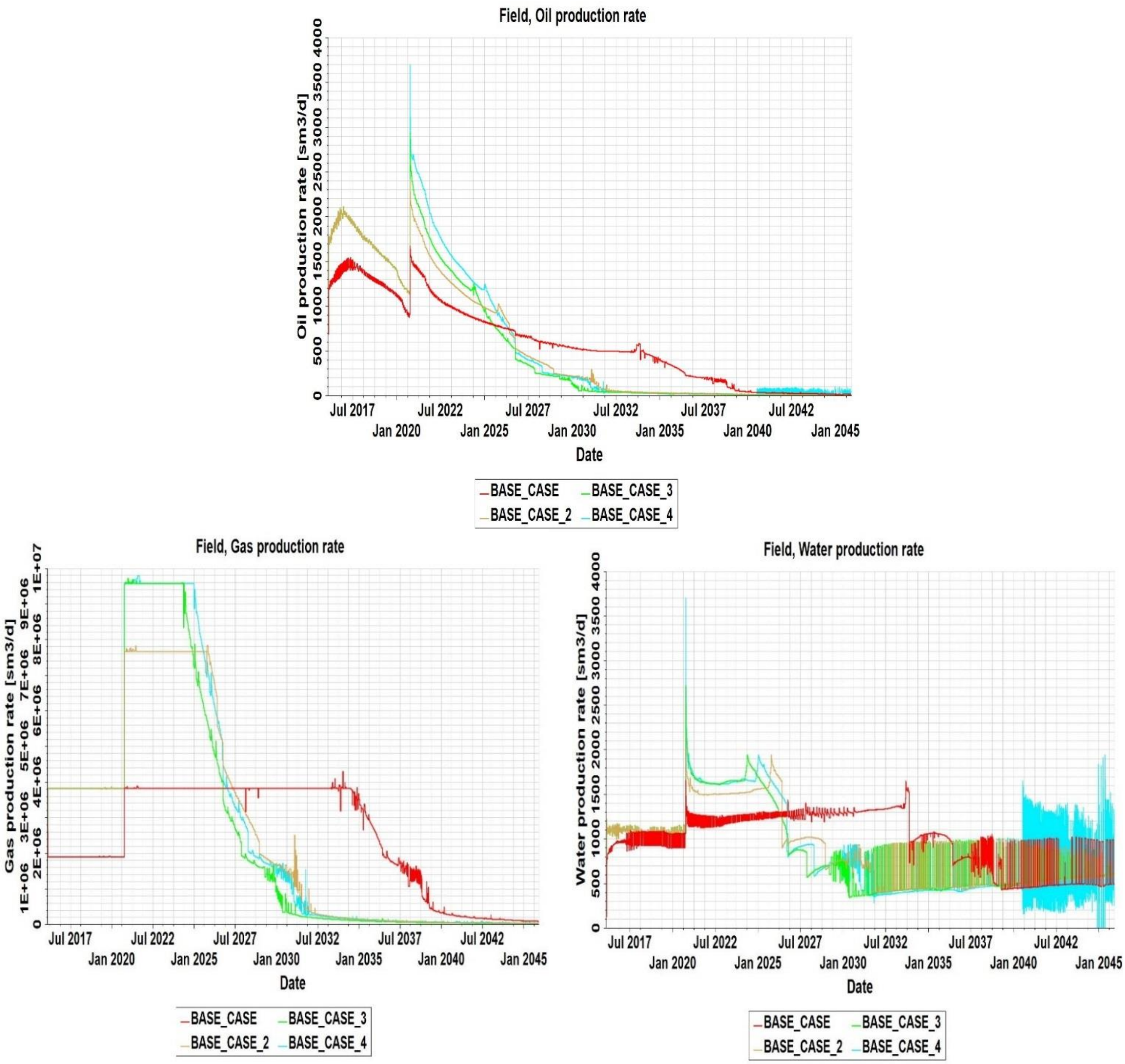

Figure 17: Field oil production rate (up), field gas production rate (lower left), field water production rates (lower right); Base case (red), Base case 2 (brown), Base case 3 (green), Base case-4 (blue)

From the production rate profiles in figure 17, it is seen that, the base case gives lower oil production rates during early years, from 2020 to 2026; However, later the oil production rate in the base case is higher than the other cases until 2040. The other cases have shown almost the same tendency. The oil production rate in base case 2,3,4 dramatically decreases from 2020 to 2030.

The gas production rates show the same trend. In the base case the gas production rate is constant to $3.81x10^6$ sm^3/d in years 2020-2034, which gives a better pressure support to the reservoir than the other cases. Higher oil production rate has been observed for the base case during that time because of this pressure support. After, 2034 the gas production rate decreases dramatically and reaches to almost zero by 2044. In base case 3 & 4 the gas production rate is constant with a very high rate of $9.58x10^6$ sm^3/d for few years, 2020-2024 for base case 3 and 2020-2025 for base case 4; then a dramatic decrease in the gas production has been observed as the gas production rate in the production wells (i.e. P-11, P-12, P-20) in Oseberg, Rannoch, Etive and lower ness formation has shown higher depletion (figure 47 and figure 51). The water production rate also has the same trend as the oil and gas production rate.

This phenomenon is caused due to the depletion of pressure (figure-20), which will result in the decrease in well influx (oil, gas and water). The total well influx decreases as the bottom hole pressure in some wells fall below the bottom hole pressure constraint and causes the wells to shut down. For this reason, the rapid decrease in oil (figure 42, 46, 50) and gas (figure 43, 47, 51) production has been observed in different wells.

Cumulative production:

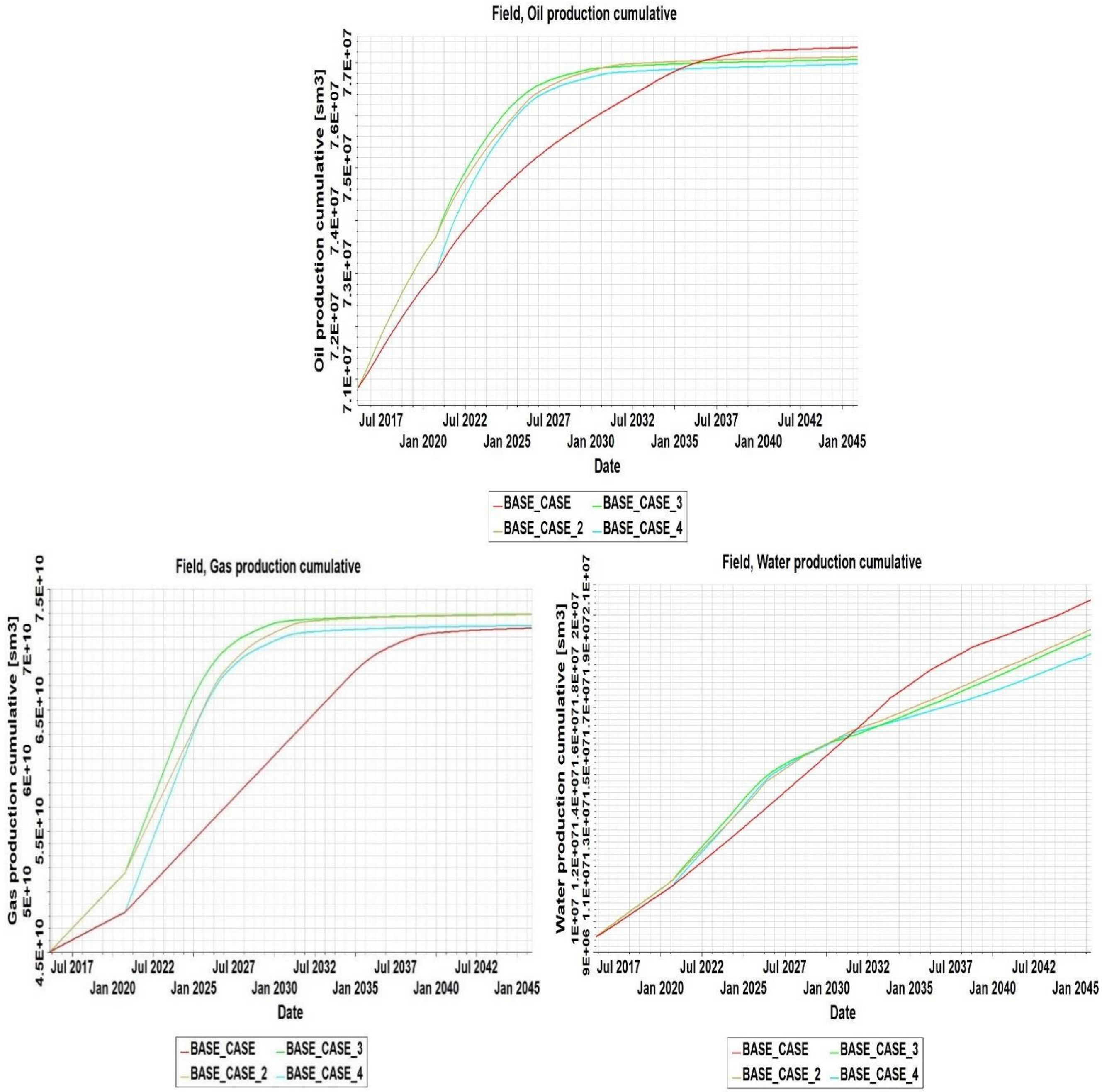

Figure 18: Total oil production (up), total gas production (lower left), total water production (lower right); Base case (red), Base case 2 (brown), Base case 3 (green), Base case-4 (blue)

From figure 18, it is seen that, the base case gives the highest amount of cumulative oil production (7.73×10^7 sm^3), while the other cases; base case 2 and 3 give almost the same total amount of oil (7.71×10^7 sm^3). Base case 4 gives less amount among all of the cases (7.69×10^7 sm^3). Moreover, in base case 2,3 and 4, the oil production has been accelerated compared to the base case. In case of gas production, the base case and base case 4 gives the same amount ($7.19x10^{10}$ sm^3) while base case 2 & 3 gives higher amount of produced gas ($7.29x10^{10}$ sm^3).

Gas-Oil Ratio and Water Cut:

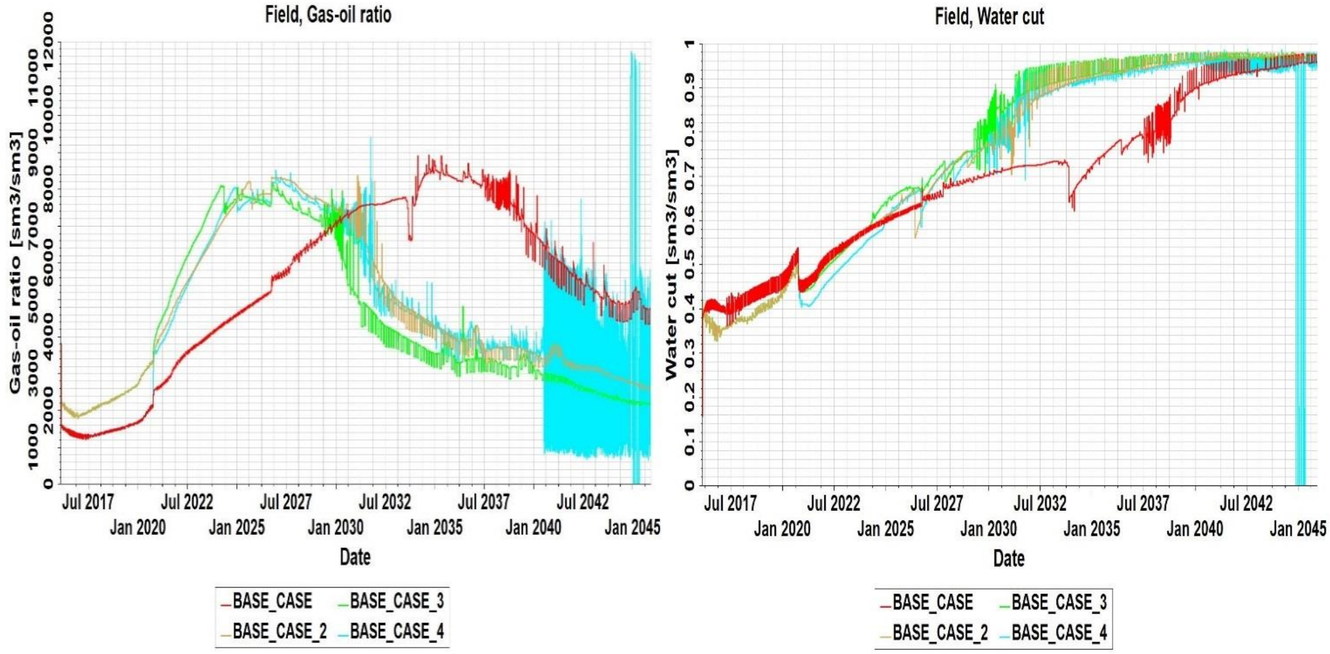

Figure 19: Field gas-oil ratio (left), field water cut (right); Base case (red), Base case 2 (brown), Base case 3 (green), Base case-4 (blue)

From figure 19, it is seen that, in base case, the gas-oil ratio slightly decreased at the beginning as oil production increased (figure 17) with constant gas production rate for some time. After, 2020 the gas-oil ratio increased gradually as the oil production depleted with increased constant gas production rate and reaches to its plateau of 8500 sm^3/sm^3 around 2032. The increase in gas-oil ratio is observed due to the production of solution gas and the free gas from the gas cap. At the end, gas-oil ratio depleted as gas production decreases dramatically and water cut increases. The similar trend has also been observed in other cases. High gas-oil ratio has been observed for base case 2,3,4 in early gas export years, 2020-2028. The observed average values for three cases are 7600, 7800 and 7900 sm^3/sm^3 respectively. The gas-oil ratio started to decrease after 2028, which also indicates the depletion in gas production and increase in water cut. However, higher fluctuation of gas-oil ratio has been observed in different wells in different base cases (figure 41, 45, 49, 53); i.e. in base case 4, a high fluctuation of gas-oil ratio has been observed (figure 53) as production well P-18 and P-19 started to show inconsistency (shut down and re-opened) after 2035. It is may be due to the error in numerical calculations during the simulation run. In that case, the best estimate can be considered by taking the average between the maximum and minimum value in the fluctuated region. Moreover, Water breakthrough has been observed (figure-40), in some production wells (i.e. P-21, P-11) as the location of the wells are adjacent to the aquifer. Water coning could be the another reason for the water influx, as high gas rates has been utilized.

Pressure profiles:

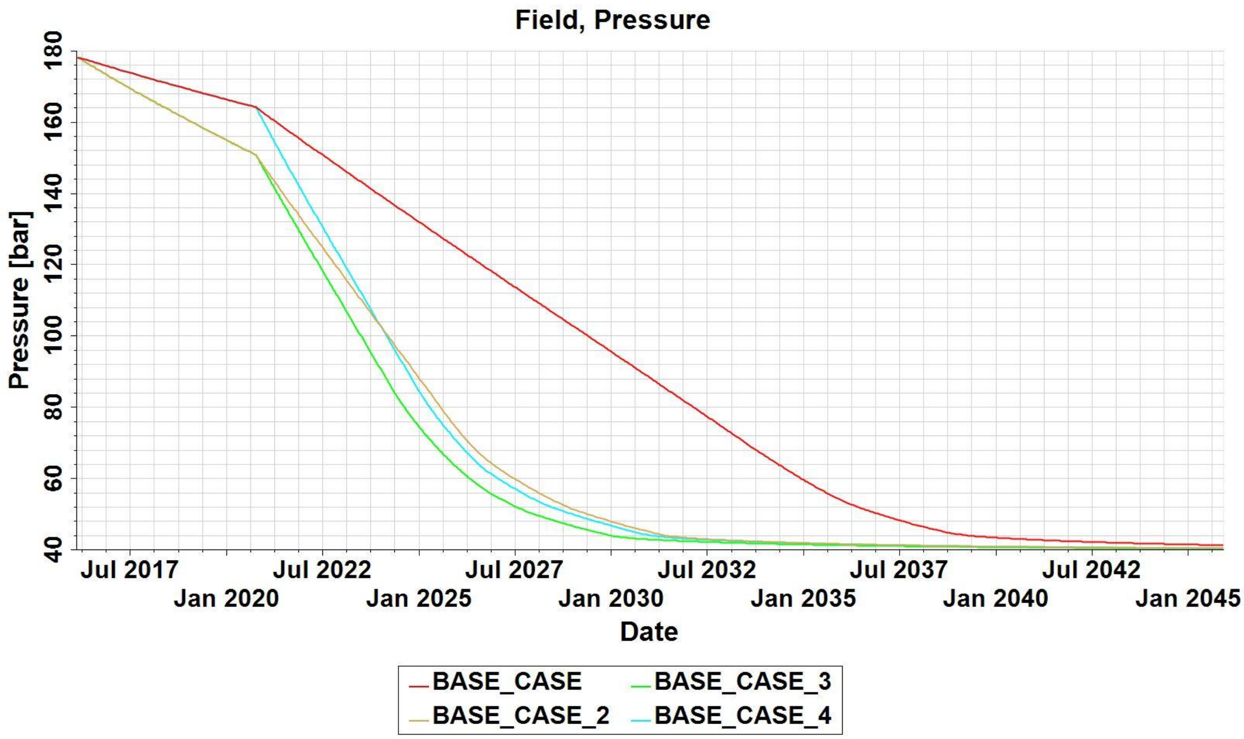

Figure 20: Field pressure for base cases; Base case (red), Base case 2 (brown), Base case 3 (green), Base case-4 (blue)

In figure 20, for Base case and 4, the pressure is depleted about 15 bar from 2016-2020; and in case of base case 3 and 4 the pressure is depleted about 30 bar. After Feb 2020, due to the high rate of gas production, the reservoir pressure depleted dramatically and reach 40 bar in base case 2,3,4; while in the base case the pressure depleted gradually until 2040. This different decrease in pressure is caused due to different gas export rates (figure 17). The pressure started to deplete rapidly with high gas export rates. As the pressure is depleting further below the bubble point of the oil, more gas will be liberated from the oil, which also have an impact on the gas-oil ratio (Figure 19). The decrease in pressure will cause to liberate more gases from the oil, which will be resulting in higher production of gas and decrease in the oil production.

Oil recovery efficiency:

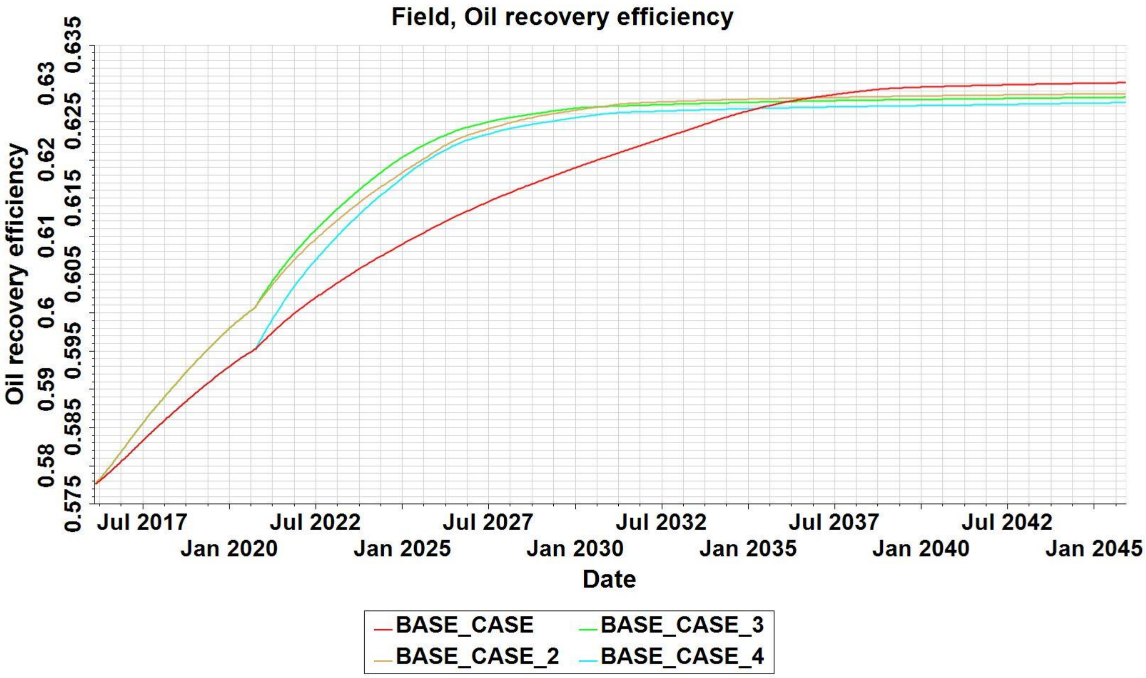

Figure 21: Oil recovery efficiency for base cases; Base case (red), Base case 2 (brown), Base case 3 (green), Base case-4 (blue)

In figure 21, the base case gives the ultimate oil recovery of 63.01% when the production is prolonged to 2045 with a gradual depletion of pressure. The other cases 2,3 and 4 provides high recovery of oil in early gas export years after 2020. In Jan 2032, the oil recovery for base case and base case 2,3,4 are 62.18%, 62.63%, 62.71% and 62.75% respectively. The base case 2,3 and 4 reaches to its ultimate recovery of oil earlier (by 2035) then the base case (2042) because of the higher gas export from the beginning.

6.4.2 Summary

The base case provides higher amount of oil recovery than the other cases, because of the pressure in the base case decreases gradually with low gas production rate while the pressure in the other cases decreases dramatically with the high gas production rate. The produced and remaining liquid volumes for different base cases are given in table 15,

Table 15: Produced and remaining liquid volumes for different base cases

Formation	Produced Oil (Msm^3) Dec, 2045	Remaining OIP (Msm^3) Dec, 2045	Produced gas (Bsm^3) Dec, 2045	Remaining GIP (Bsm^3) Dec, 2045	Recovery of oil (%) Dec, 2045
Base case	77.29	45.36	71.78	7.71	63.01
Base case_2	77.11	45.54	72.87	7.52	62.86
Base case_3	77.05	45.60	72.90	7.49	62.82
Base case_4	76.97	45.68	71.97	7.51	62.76

However, simulated results also showed that, base case 3 provides higher amount of oil and gas recovery in early years (figure-21) than the other cases and reaches to ultimate production of oil by 2030; while the base case reaches to its ultimate oil production in 2042. Moreover, base case 2 gives a little bit higher oil recovery than base case 3, but the amount of oil recovered for base case 3 before 2030 is higher than base case 2, which makes base case 3 more desirable than the other cases. considering the base case 3, it has been observed that, the oil recovery gained in 2045 for Tarbert, Ness and ORE are 51.40%, 42.07% and 80.69% respectively; which makes total recovery of oil 62.82% and the produced amount of gas in total is 222.14 Bsm^3 and the remaining total amount of gas is 7.49 Bsm^3. Table 16 presents the produced and remaining liquid volumes of Beta Brent reservoir for base case 3.

Table 16: Produced and remaining liquid volumes of Beta Brent reservoir for base case 3

Formation	Oil initially in place (Msm^3)	Produced Oil (Msm^3) Dec, 2045	Remaining OIP (Msm^3) Dec, 2045	Produced gas (Bsm^3) Dec, 2045	Remaining GIP (Bsm^3) Dec, 2045	Recovery of oil (%) Dec, 2045
Tarbert	35.66	18.33	17.33	72.90	1.67	51.40
Ness	29.69	12.49	17.21	74.05	2.13	42.07
ORE	57.29	46.23	11.06	75.19	3.69	80.69
SUM	122.65	77.05	45.59	222.14	7.49	62.82

6.5 Results from Gas export scenarios

The production profiles and the discussion of the profiles of all four gas export scenarios are given below. The production profiles of the wells of each individual Scenario has been presented in

6.5.1 Production profiles

Production rates:

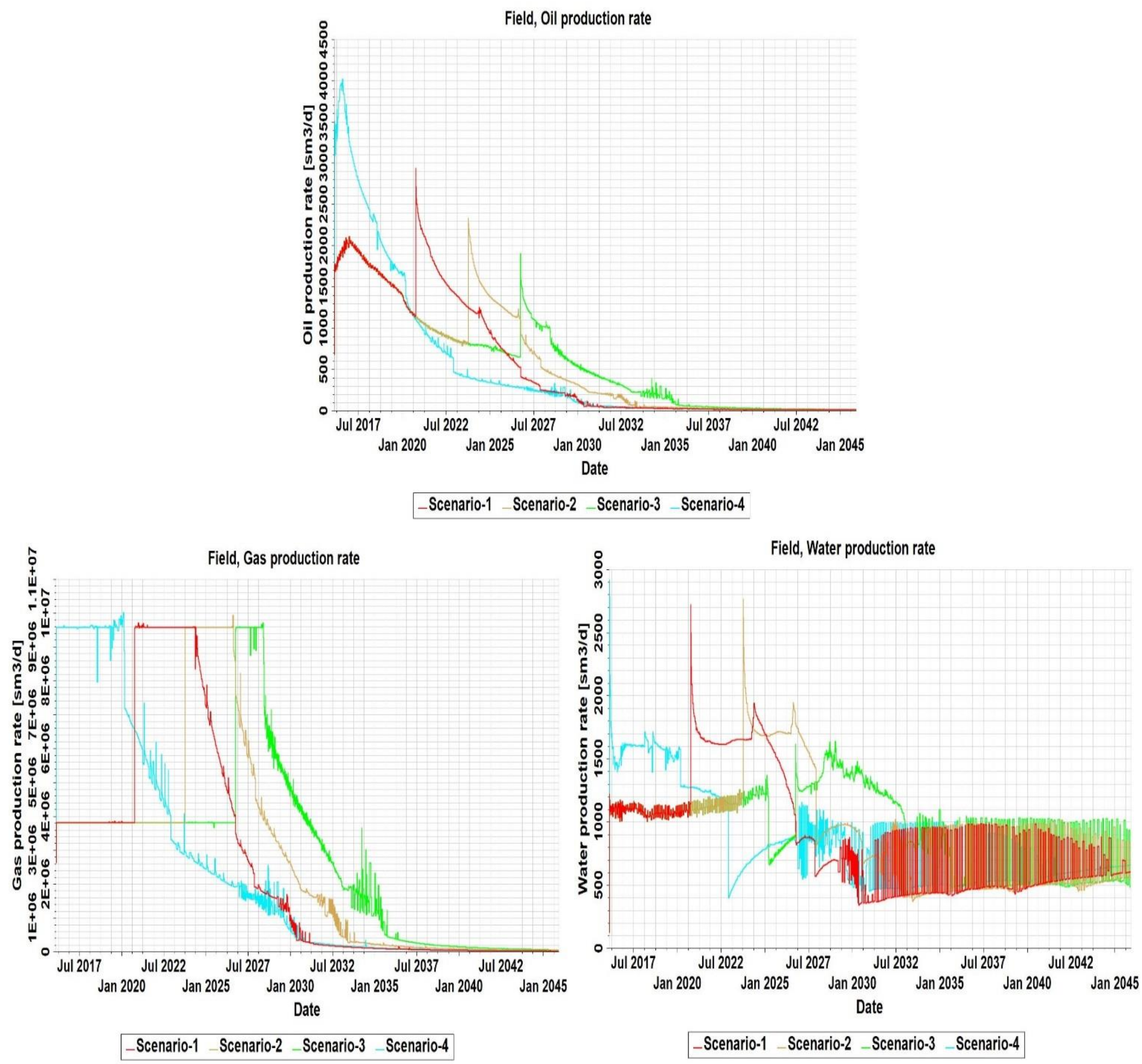

Figure 22: Gas export scenarios; field oil production rate (up), field gas production rate (lower left), field water production rates (lower right); Scenario-1 (red), Scenario-2 (brown), Scenario-3 (green), Scenario-4 (blue)

From the production rate profiles in figure 22, it is seen that, scenario-4 gives highest oil production rates during early years, from 2016-2019; However, later the oil production rate decreases rapidly and after 2030 very low rate has been observed. The other scenarios have shown almost the same tendency after the start of blowdown phase. At the beginning of blowdown phase, high oil production rate (2000-2500 sm^3/d) has been observed and the oil production rate dramatically decreases to almost zero in next 10 years.

In case of gas production, the duration of the plateau rate differs for different scenarios. In case of scenario-4, the gas production rate maintained its plateau rate of 9.51×10^6 sm^3/d from 2016-2020; while for scenario-1, scenario-2 and scenario-3, the same plateau has been observed for 4 years, 3 years and 2 years respectively. In all the scenarios, dramatic depletion of the gas production has been observed, once the plateau rate finishes for each scenario, as the gas production rate in the production wells (i.e. P-11, P-12, P-18 and P-20) in Oseberg, Rannoch, Etive and lower ness formation has shown higher depletion (figure 47, 55, 59 and 63). This is caused due to the shutdown of some wells as the bottom hole pressure fall below 40 bar (constraint).

Cumulative production:

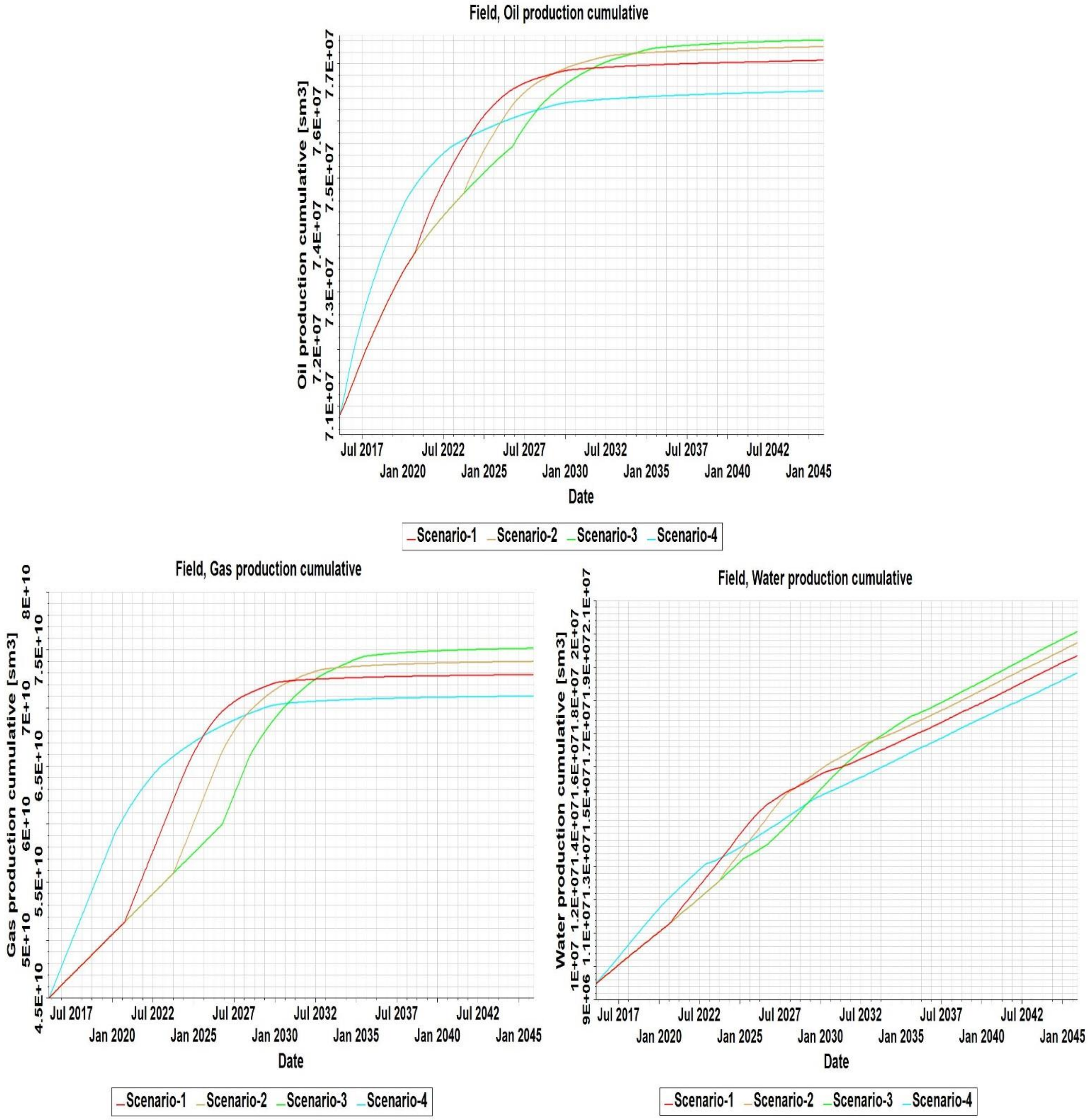

Figure 23: Gas export scenarios; total oil production (up), total gas production (lower left), total water production (lower right); Scenario-1 (red), Scenario-2 (brown), Scenario-3 (green), Scenario-4 (blue)

In figure 23, it is seen that, scenario-3 gives the highest amount of cumulative oil production ($7.74x10^7$ sm^3), while the other cases; scenario-2 and scenario-1 gives total amount of oil $7.73x10^7$ sm^3 and $7.71x10^7$ sm^3 respectively. The scenario-4 gives less amount among all of the cases ($7.65x10^7$ sm^3). Moreover, high acceleration of oil production has been observed for scenario-4 from 2016-2030, while in other cases high production has been observed for the next 10 years after each of the case go for blowdown respectively. In case of gas production, similar trend has been observed as the oil production. The case scenario-3 gives the highest amount of cumulative oil production ($7.52x10^{10}$ sm^3), while the other cases; scenario-2 and scenario-1 gives total amount of oil $7.40x10^{10}$ sm^3 and $7.28x10^{10}$ sm^3 respectively. Meanwhile, scenario-4 gives $7.12x10^{10}$ sm^3.

Gas-Oil Ratio and Water Cut:

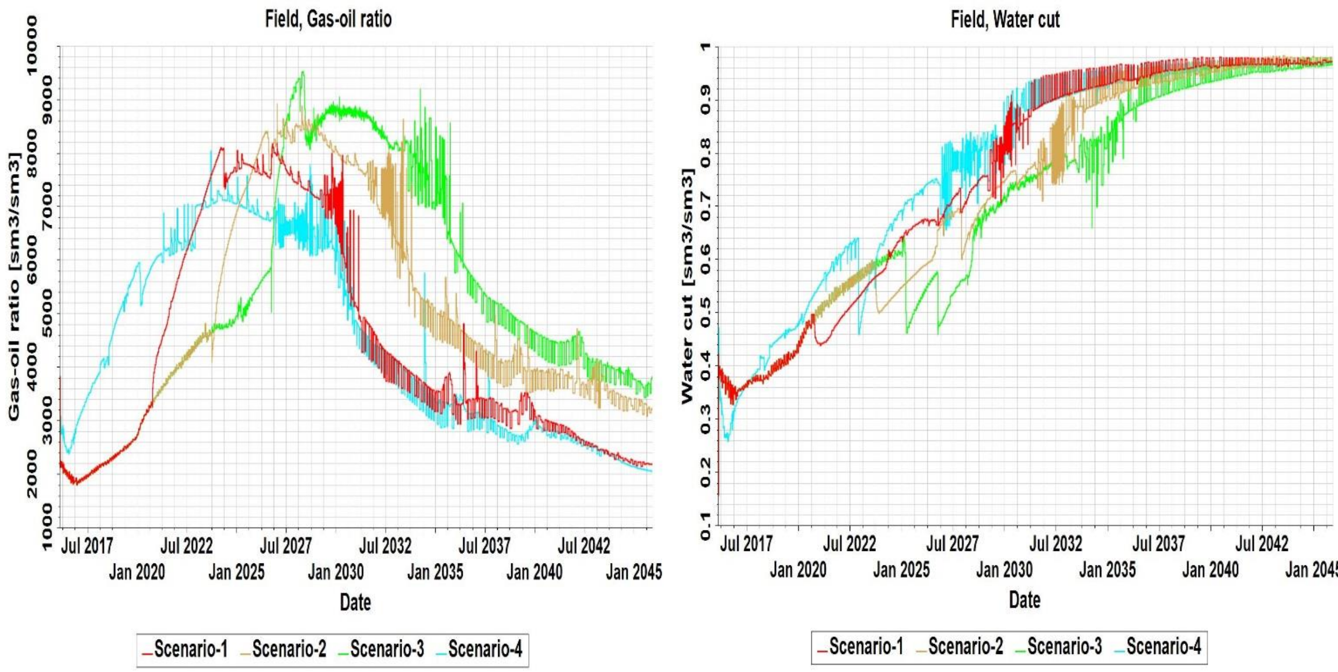

Figure 24: Gas export scenarios; field gas-oil ratio (left), field water cut (right); Scenario-1 (red), Scenario-2 (brown), Scenario-3 (green), Scenario-4 (blue)

In figure 24, in the case of scenario-4, slightly low gas-oil ratio has been observed at the beginning because of the high oil production. Then (after Jul 2017), oil production depleted dramatically which cause the increase in the gas oil ratio. After 2028, the gas-oil ratio started to decrease as the gas production decreased rapidly and water cut increased. The same trend has also been observed for the other three scenarios. The gas-oil ratio of scenario 1, 2, 3 increases rapidly with the high gas export rates. Each scenario reaches to its peak 3-4 years after continuing with the maximum gas export rates. However, the highest gas-oil ratio has been observed around 2028 and lower water cut in scenario-3. The high fluctuations in gas-oil ratio is caused in the later production because some of the well (i.e. P-5, P-9, P-8) shows inconsistency (shut down and reopened) (figure 49, 57, 61, 65) for the same reasons as before (discussed in chapter 6.4.1).

Pressure profiles:

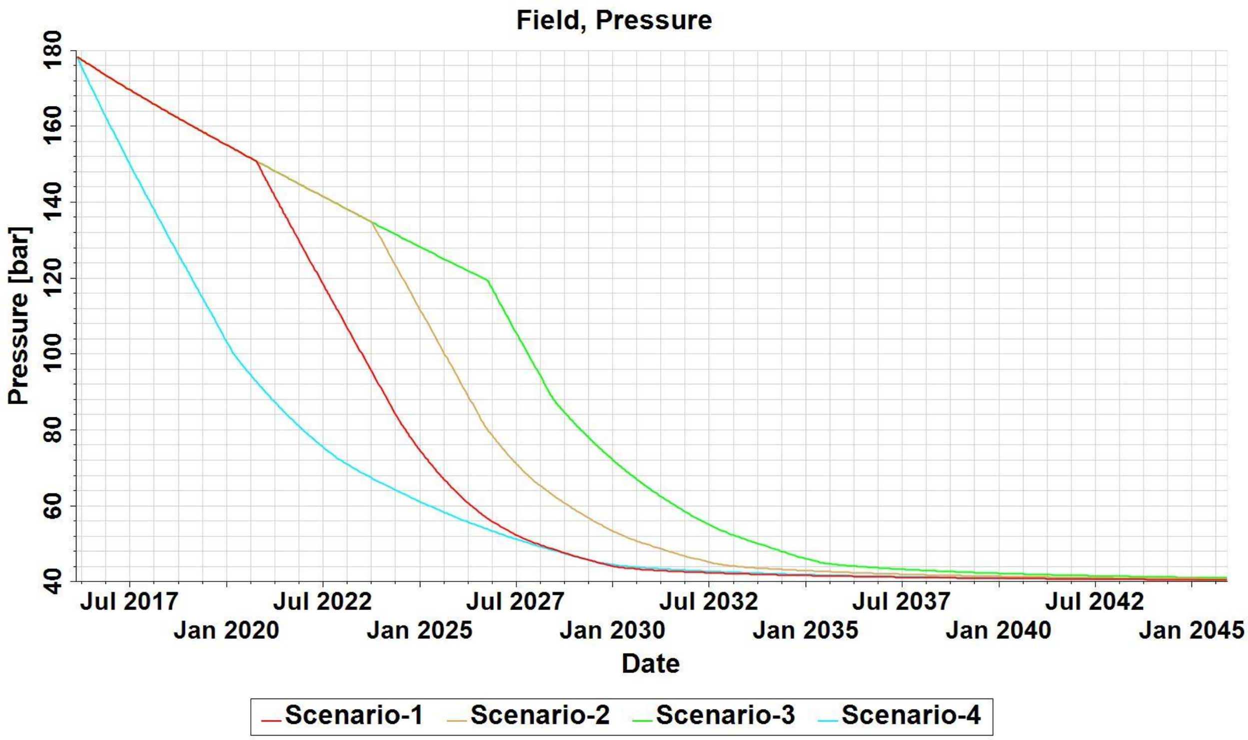

Figure 25: Gas export scenarios; field pressure; Scenario-1 (red), Scenario-2 (brown), Scenario-3 (green), Scenario-4 (blue)

From the pressure profiles in figure 25, it is seen that, the field pressure of the scenario-4 has been depleted dramatically once the gas blowdown started and pressure depleted approximately 130 bar from 2016-2030. In the other scenarios, pressure drawdown of 130-135 bar has been observed in next 10-12 years, once each case goes for gas blowdown.

Oil recovery efficiency:

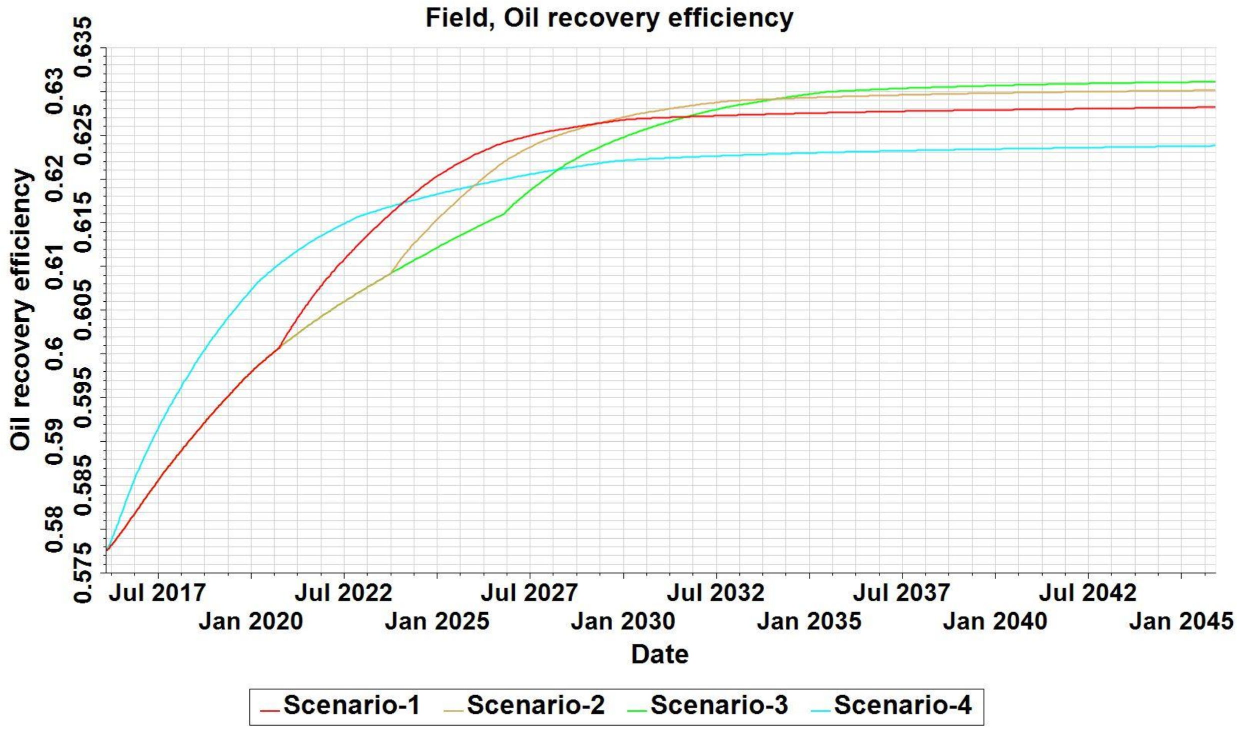

Figure 26: Gas export scenarios; oil recovery efficiency; Scenario-1 (red), Scenario-2 (brown), Scenario-3 (green), Scenario-4 (blue)

From the figure 26, it is seen that, implying high export rate (scenario-4), is resulting in rapid depletion in pressure (figure 25), which gives high oil recovery at the beginning; but the low ultimate oil recovery has been achieved by 2028, once the pressure falls near 40 bar. Moreover, implying lower export rate (scenario-3) results in gradual fall of pressure, which gives low oil recovery at the beginning, but the ultimate oil recovery is much higher because of the maintenance of high pressure in the reservoir for long time. So, it is seen that, delaying the gas blowdown increases the oil recovery. Scenario-3 gives the highest recovery of oil 63.12% in 2045. The gas export case, Scenario-4, shows the lowest oil recovery of 62.29%. the It is also observed that all the different cases reach to ultimate oil recovery by 2037.

6.5.2 Summary

The case, Scenario-3 gives the higher recovery of oil (63.12%) and the scenario-4 gives the lowest oil recovery (62.29%). Prolonging the low gas export rates will increase the oil recovery and also total gas production. However, going for early high gas export, i.e. gas blowdown, will give high oil recovery in early years, but the ultimate recovery will be lower. From all the cases it is also seen that, all the cases reach to its ultimate oil recovery by 2037. So, in this study, production can be shortened to 2037.

Table 17, presents the produced and remaining liquid volumes of Beta Brent reservoir for different gas export scenarios.

Table 17: Produced and remaining liquid volumes for different gas export scenarios

Formation	Produced Oil (Msm^3) Dec, 2045	Remaining OIP (Msm^3) Dec, 2045	Produced gas (Bsm^3) Dec, 2045	Remaining GIP (Bsm^3) Dec, 2045	Recovery of oil Dec, 2045
Scenario-1 (Base case 3)	77.05	45.60	72.90	7.49	62.82
Scenario-2	77.30	45.55	74.05	7.56	62.92
Scenario-3	77.42	45.43	75.19	7.62	63.12
Scenario-4	76.53	46.32	71.07	7.48	62.29

Chapter 7

7.1 Conclusion and recommendation

Conclusions:

Based on this simulation study the following conclusions can be made-

- Injecting more gas (import case) in the reservoir will not give significant oil recovery than the gas export case (base case). The oil recovery for the import case is almost the same as the base case during 2016-2035. Eventually, in 2045, the oil recovery for the import case and base case are 64.4 % and 63.01%.
- If the gas export rate is higher, then the oil recovery factor will be lower and the ultimate recovery will be obtained quickly. Base case 3 provides higher amount of oil and gas recovery in early years than the other cases and reaches to ultimate recovery of oil (62.82%) by 2030; while the base case reaches to its ultimate oil recovery (63.01%) in 2042.
- Prolonging the duration of low export of gas (i.e. delaying maximum gas blowdown) will increase the oil recovery and also the total amount of produced gas. However, early high gas export rate (i.e. early maximum gas blowdown) can reduce the oil recovery. Scenario-3 gives the higher recovery of oil (63.12%) while scenario-4 provides the minimum (62.29%).

Recommendations:

- Further aquifer studies needed to be done as the aquifer have an extensive impact on the reservoir pressure.
- In this study only import case (injection case) and base case (no injection) has been evaluated. However, sensitivity of the gas injection can be studied, which may provide more interesting result on an economic prospect of view.
- Extensive economic analysis should be done before taking a decision to depressurize the field. In case of a large field model, a slight increase in oil recovery can have a significant benefit economically. Early gas blowdown can only be implemented if the extraction of oil isn't further beneficial to produce.
- Well placement studies can be done to increase the sweep efficiency.

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Abbreviations

BETA_HM	Beta Brent history model
BETA _OMIX	Beta Brent formations (Both NETA & ORE)
BETA _NETA	Beta Brent (Ness and Tarbert)
BETA _ORE	Beta Brent (Oseberg-Rannoch-Etive)
COIP	Contacted oil in place
GM	Gamma Ray
GIIP	Gas initially in place
ORE	Oseberg, Rannoch, Etive
ORLEN	Oseberg, Rannoch, Etive, Lower Ness
STOIIP	Stock tank oil-initially-in-place
OIP	Oil in place
GIP	Gas in place

Appendices

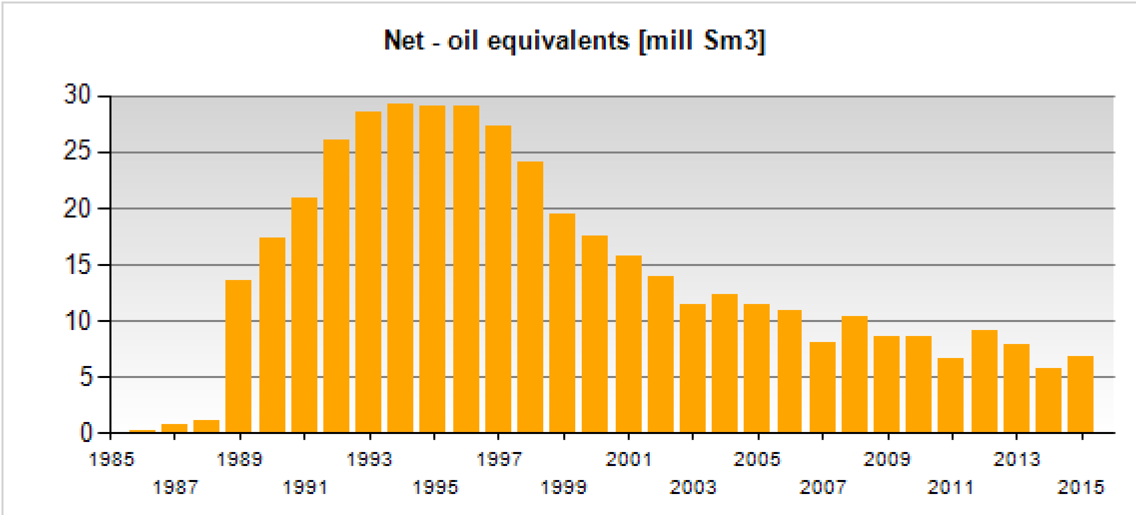
Appendix A

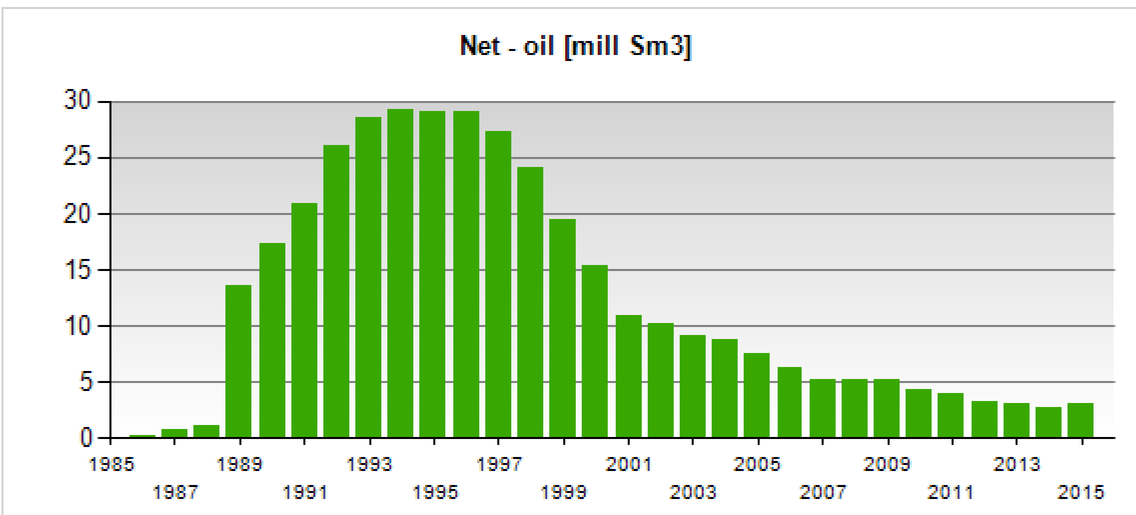
Production history of Oseberg Main field

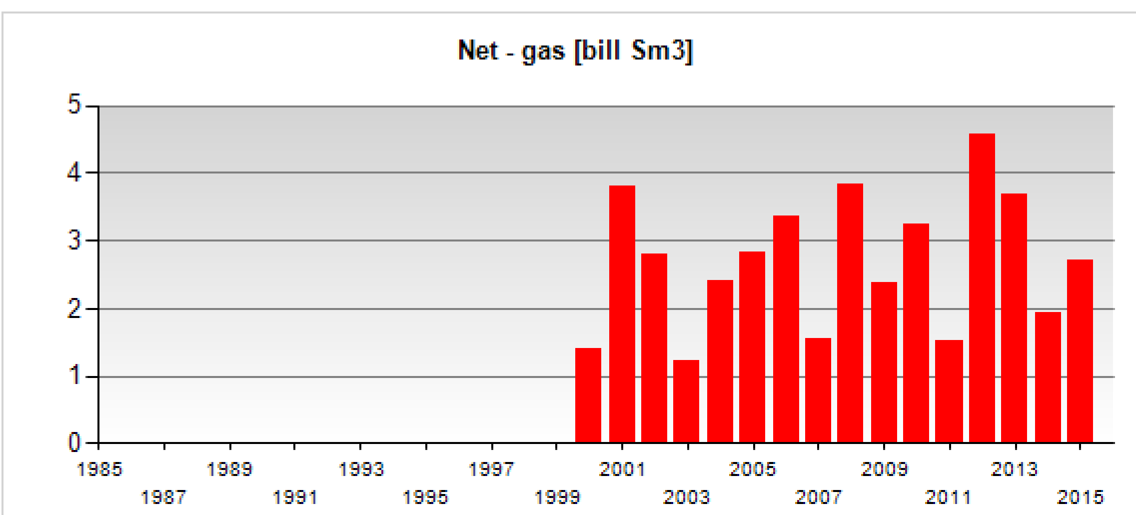
Production history net figures in Oseberg Main Field [6]

Year	Net - oil [mill Sm3]	Net - gas [bill Sm3]	Net - condensate [mill Sm3]	Net - NGL [mill Sm3]	Net - oil equivalents [mill Sm3]
Sum Prod.	**370.935837**	**43.433714**	**0.000000**	**17.632833**	**432.002384**
2016	0.283922	0.160849	0.000000	0.093525	0.538296
2015	3.036046	2.695234	0.000000	1.119618	6.850898
2014	2.731981	1.950130	0.000000	1.098368	5.780479
2013	2.998776	3.690016	0.000000	1.197539	7.886331
2012	3.310547	4.568561	0.000000	1.176477	9.055585
2011	3.913687	1.529918	0.000000	1.198949	6.642554
2010	4.309418	3.243231	0.000000	0.958897	8.511546
2009	5.125387	2.379680	0.000000	1.074853	8.579920
2008	5.292512	3.818438	0.000000	1.179027	10.289977
2007	5.163588	1.547516	0.000000	1.303025	8.014129
2006	6.261790	3.370074	0.000000	1.255171	10.887035
2005	7.466758	2.820909	0.000000	1.164678	11.452345
2004	8.713763	2.422904	0.000000	1.183984	12.320651
2003	9.175111	1.238797	0.000000	1.025059	11.438967
2002	10.112527	2.797595	0.000000	1.019130	13.929252
2001	10.970315	3.796675	0.000000	0.954909	15.721899
2000	15.410819	1.403187	0.000000	0.629624	17.443630
1999	19.435223	0.000000	0.000000	0.000000	19.435223
1998	24.101656	0.000000	0.000000	0.000000	24.101656
1997	27.268265	0.000000	0.000000	0.000000	27.268265
1996	29.126488	0.000000	0.000000	0.000000	29.126488
1995	28.985230	0.000000	0.000000	0.000000	28.985230
1994	29.211657	0.000000	0.000000	0.000000	29.211657
1993	28.462908	0.000000	0.000000	0.000000	28.462908
1992	26.104005	0.000000	0.000000	0.000000	26.104005
1991	20.915879	0.000000	0.000000	0.000000	20.915879
1990	17.308728	0.000000	0.000000	0.000000	17.308728
1989	13.514304	0.000000	0.000000	0.000000	13.514304
1988	1.125957	0.000000	0.000000	0.000000	1.125957
1987	0.807807	0.000000	0.000000	0.000000	0.807807
1986	0.290783	0.000000	0.000000	0.000000	0.290783

Production history net charts in Oseberg Main Field:







Appendix B
Production history (1991-2016) of Beta Brent reservoir

Well production rates:

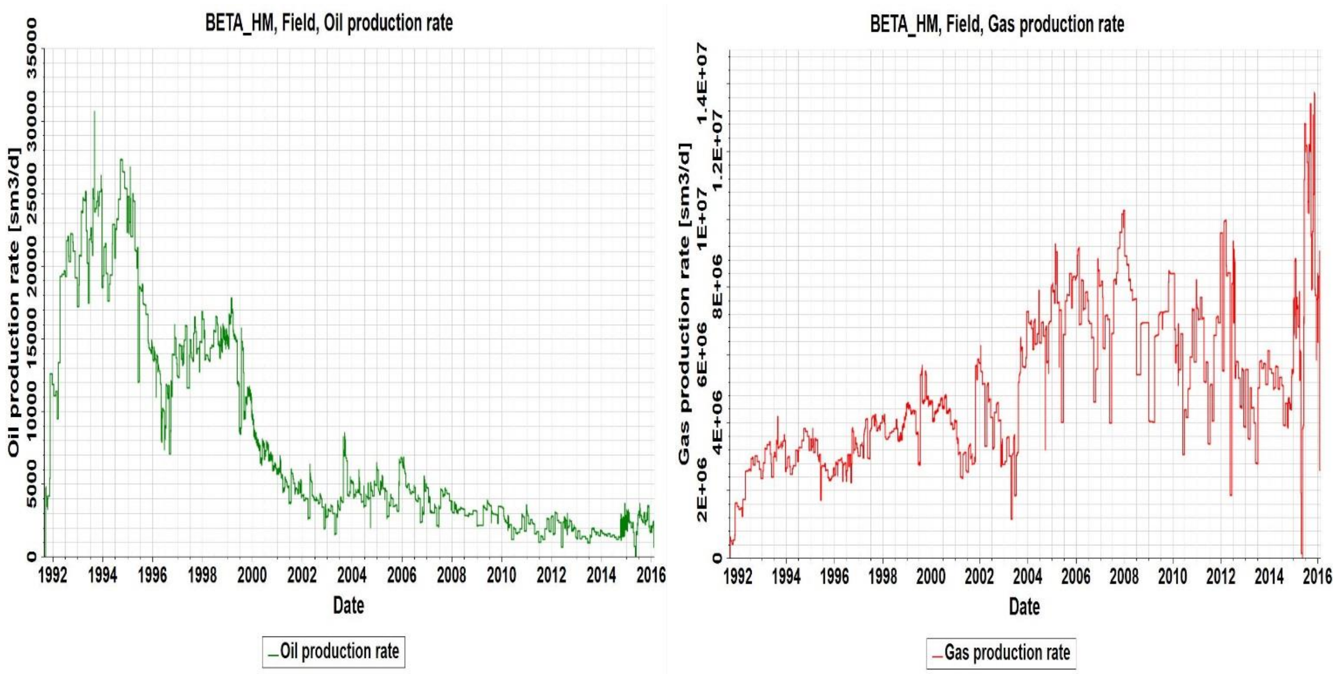


Figure 27: Beta Brent reservoir field oil production rate (left), field gas production rate (right)

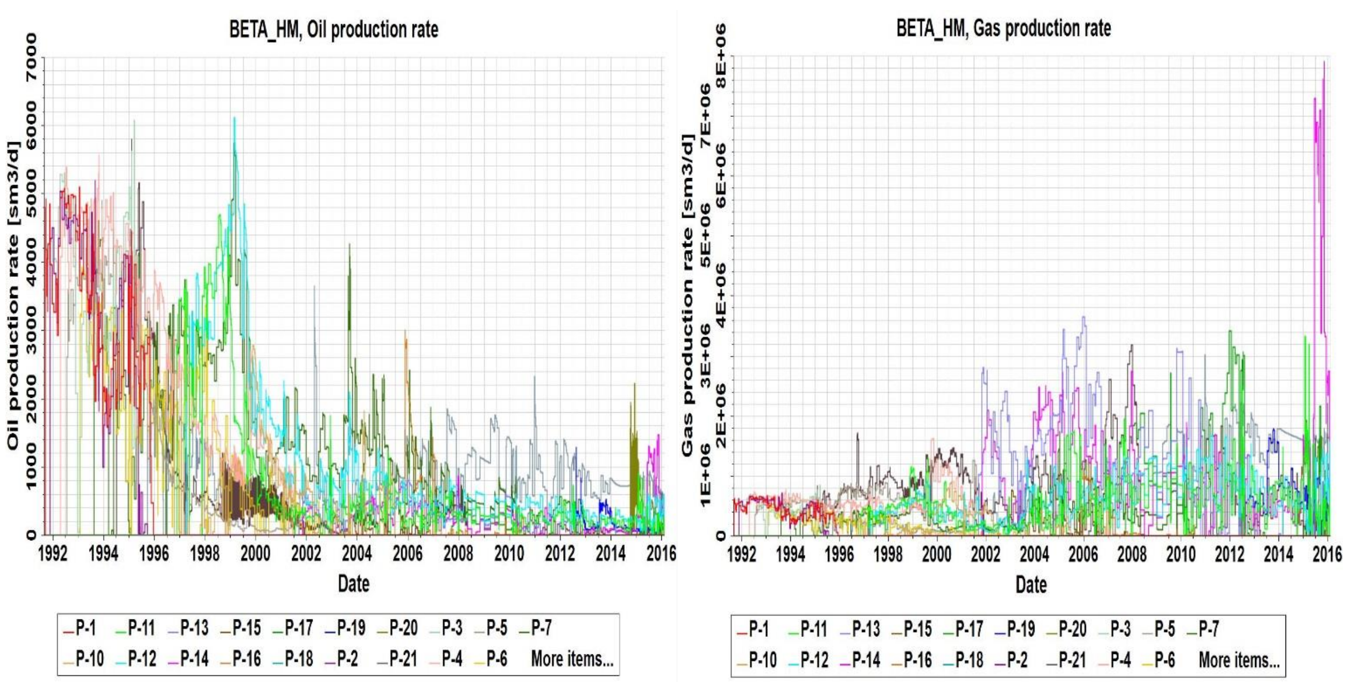


Figure 28: Beta Brent reservoir well oil production rates (left), well gas production rates (right)

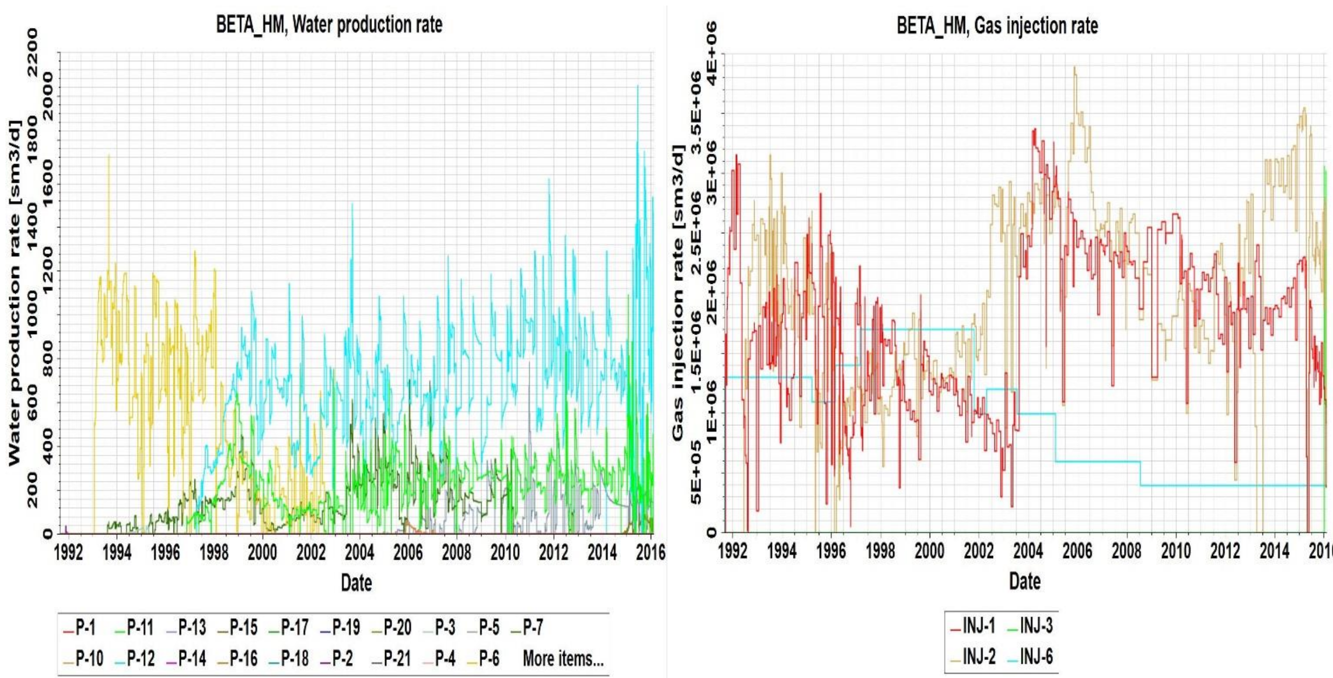


Figure 29: Beta Brent reservoir well water production rates (left), well gas injection rates (right)

Cumulative production:

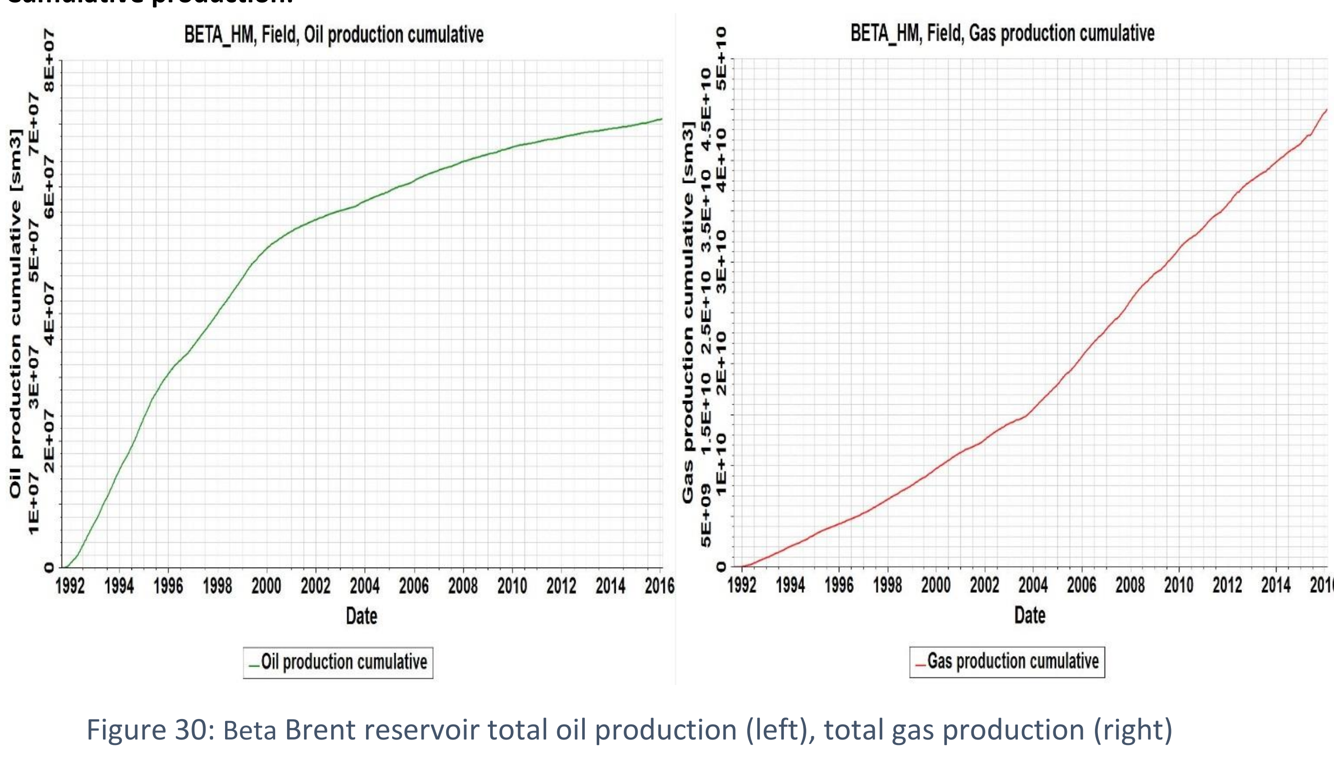


Figure 30: Beta Brent reservoir total oil production (left), total gas production (right)

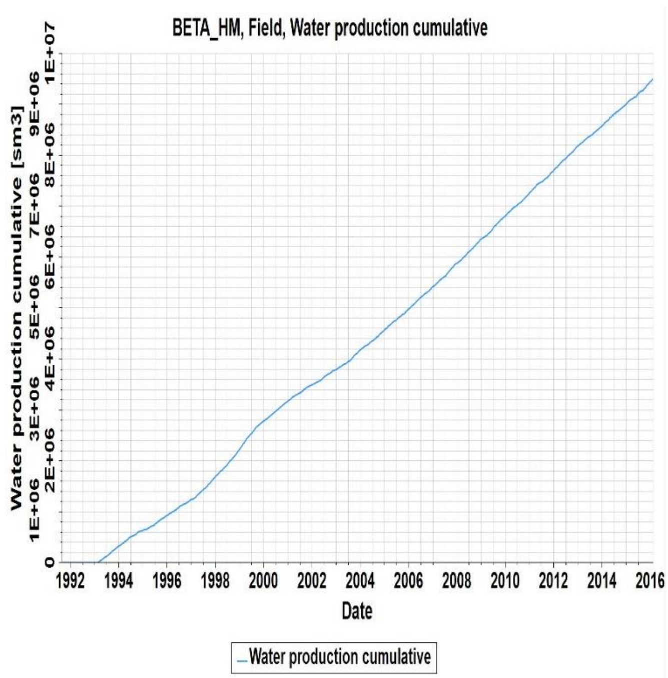


Figure 31: Beta Brent reservoir total water production (left), total gas injection (right)

Gas-Oil Ratio and Water Cut:

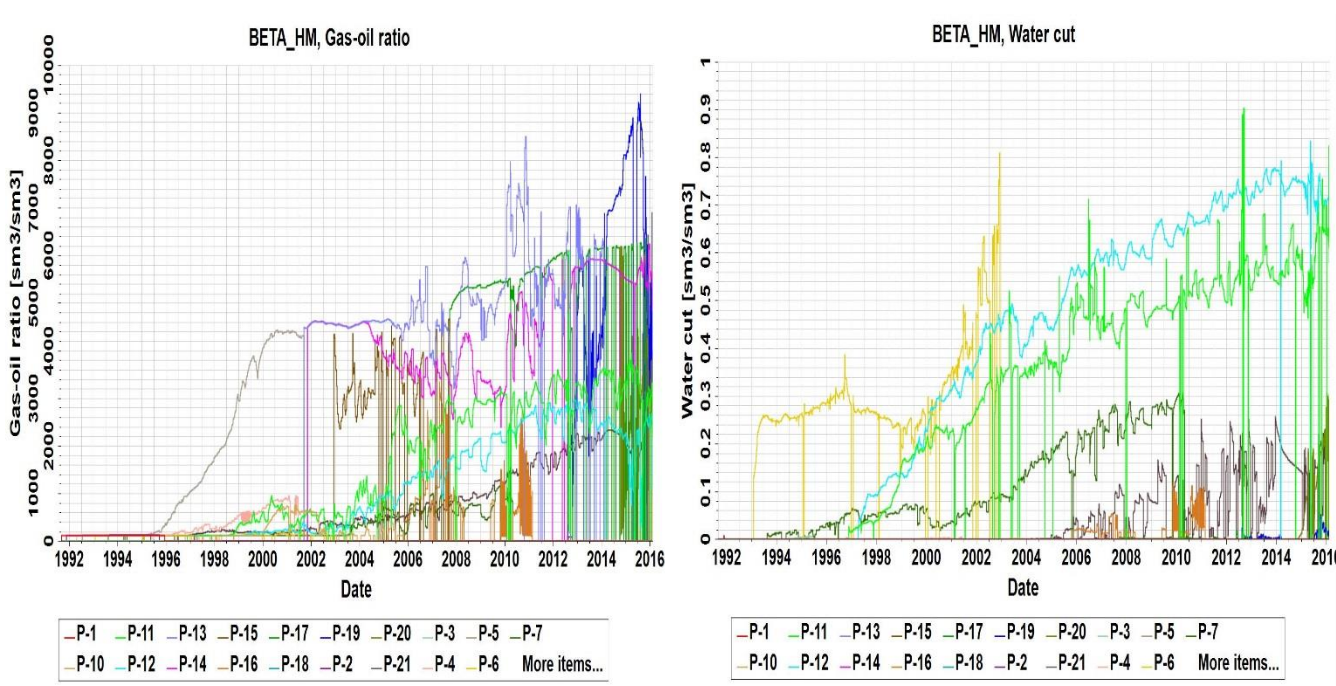
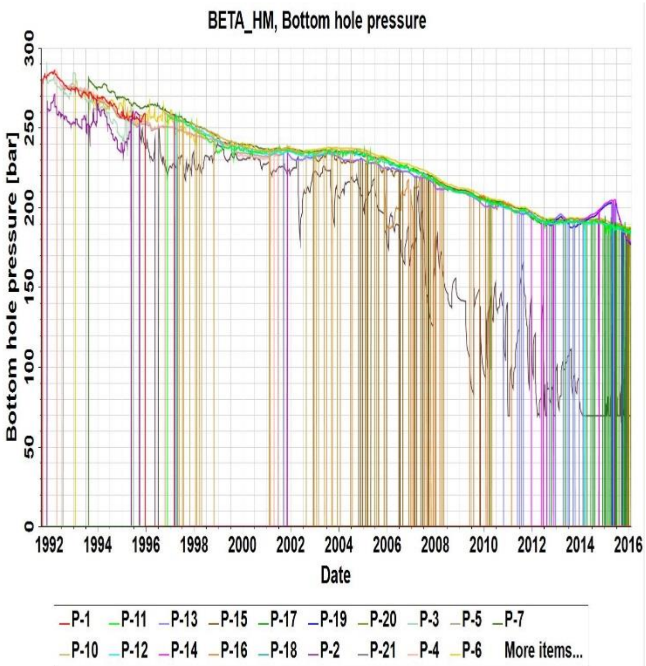


Figure 32: Beta Brent reservoir well gas-oil ratio (left), well water cut (right)

Pressure profiles:



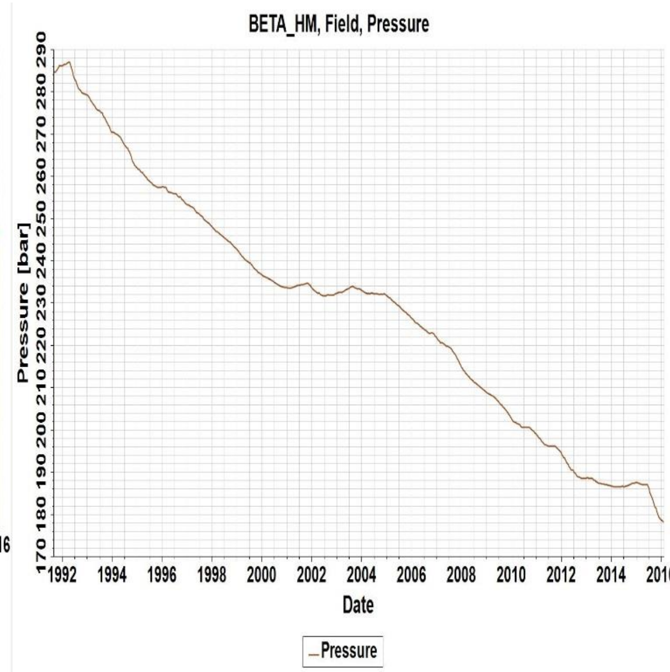


Figure 33: Beta Brent reservoir well bottom hole pressure (left), field pressure (right)

Oil recovery efficiency:

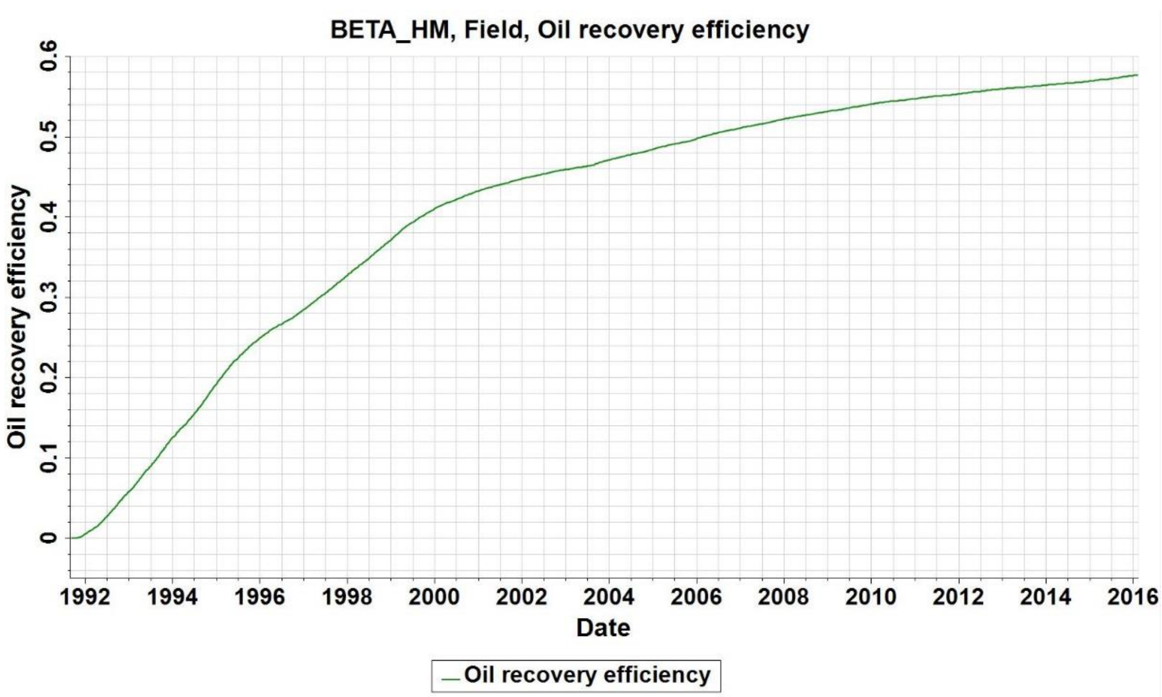


Figure 34: Beta Brent reservoir oil recovery efficiency

Appendix C
Prediction of the future field performance

Cumulative production:

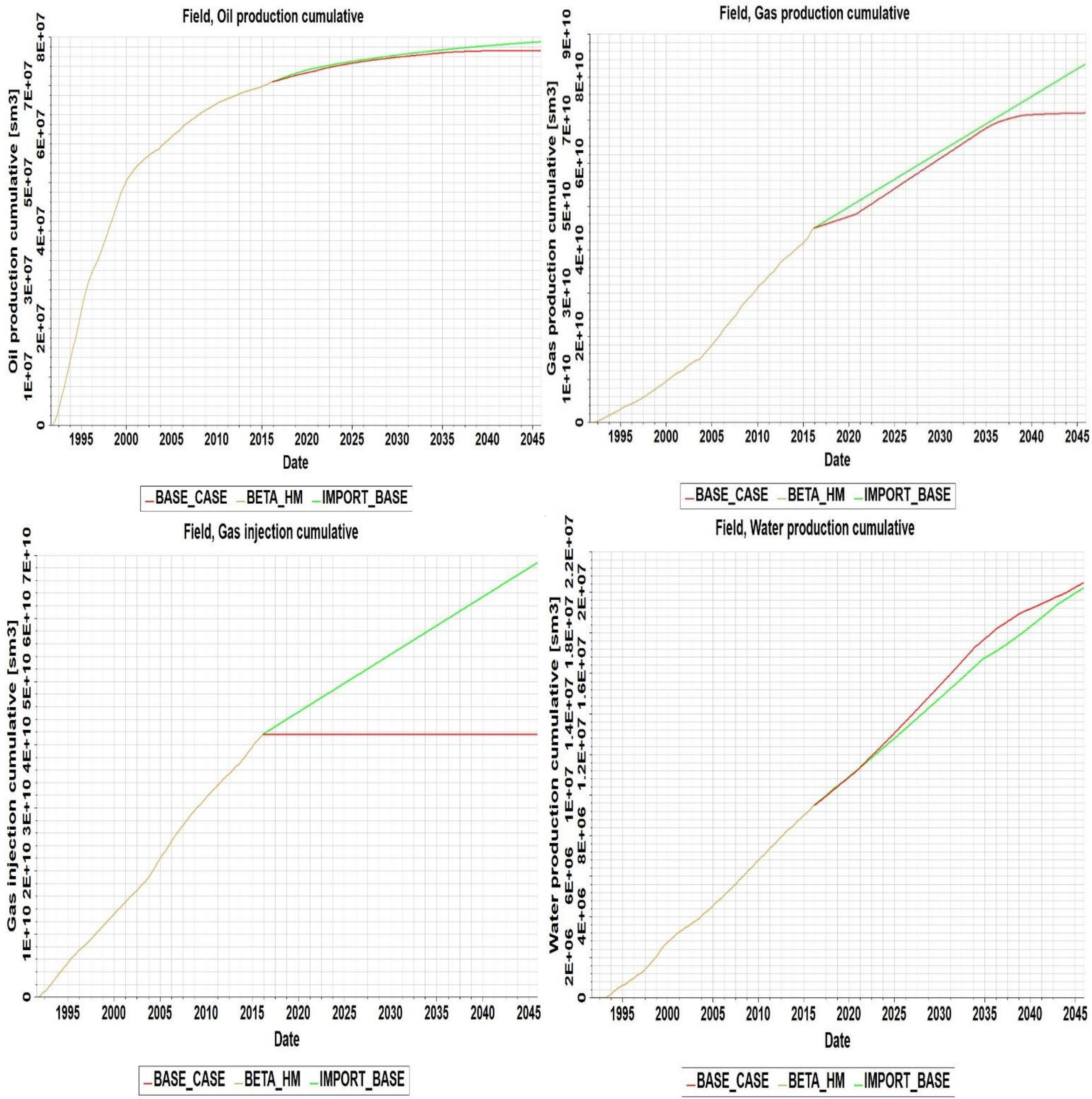


Figure 35: Prediction of the field performance; total- oil production (upper left), gas production (upper right); gas sales (lower left), water production (lower right); base case (green), import case (red), Beta_HM (brown)

Gas-Oil Ratio and Water Cut:

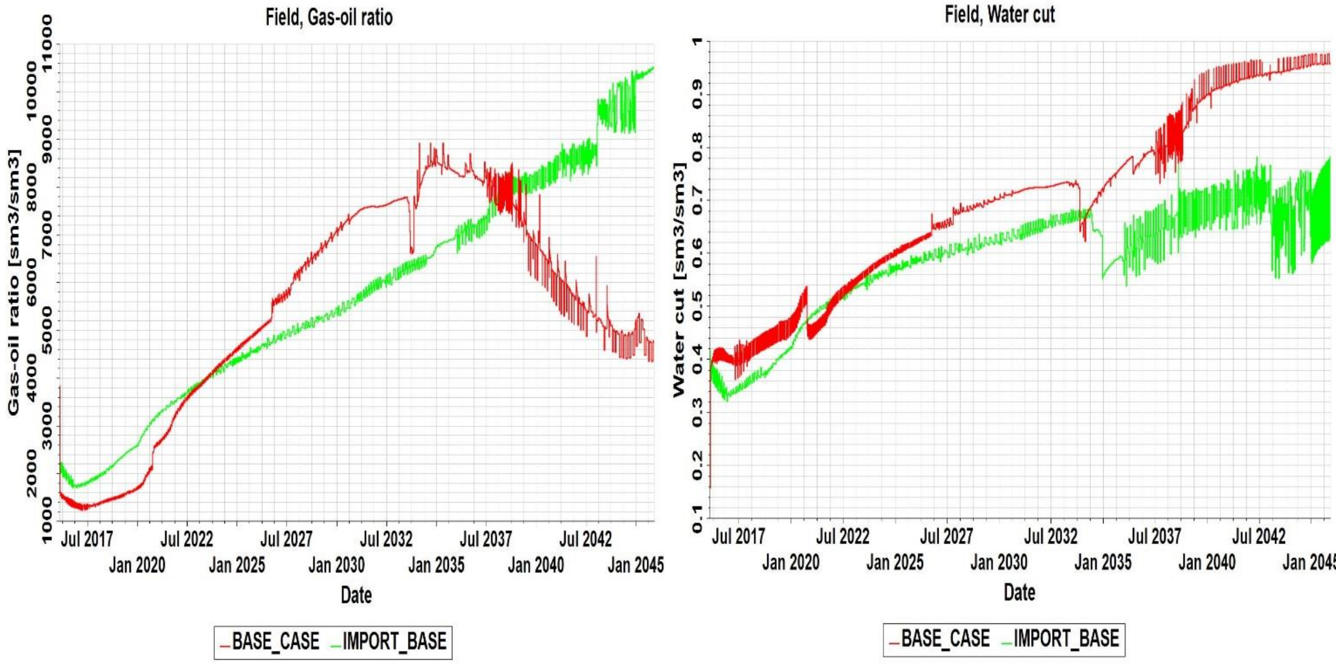


Figure 36: Prediction of the field performance; field- gas-oil ratio (left), water cut (right); base case (green), import case (red)

Pressure profiles:

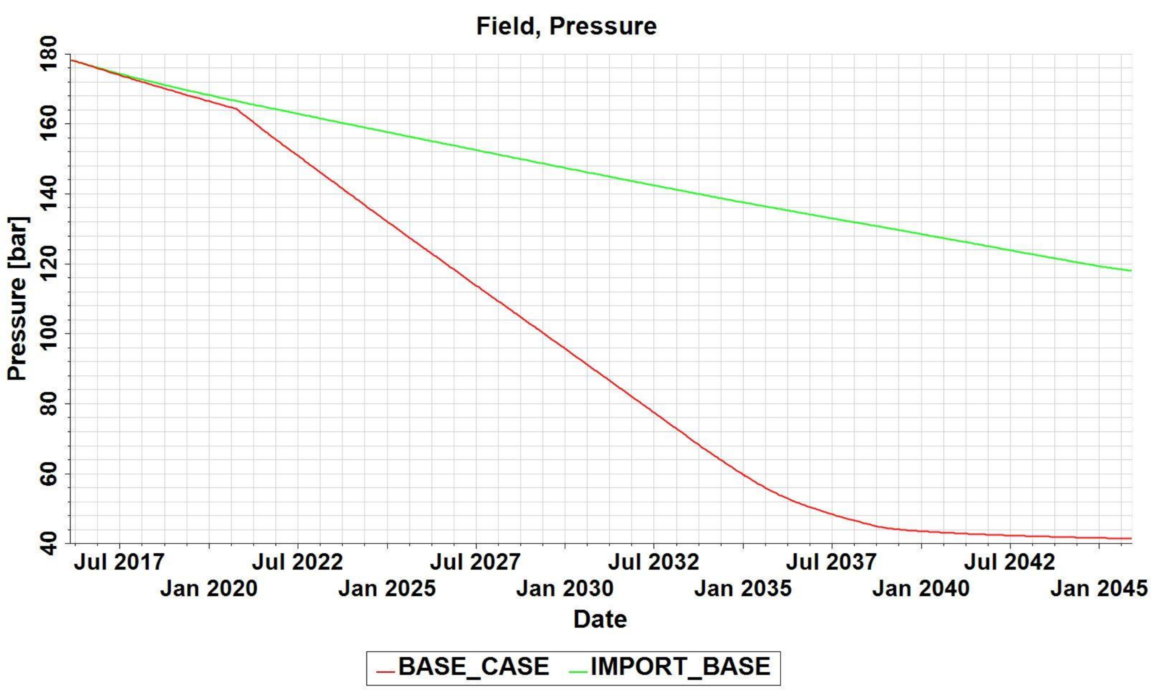


Figure 37: Prediction of the field performance; field pressure; base case (green), import case (red)

Appendix D

The well completion coordinates of active producers (after Feb 2016)

Active Production wells (After Feb, 2016):

Well	Position			
P-5	I	J	K1	K2
Perforation	89	66	5	5
	89	66	6	6
	89	66	7	7
	89	66	8	8
	90	66	8	8

Well	Position			
P-8	I	J	K1	K2
Perforation	90	73	4	4
	90	74	4	4
	90	75	4	4
	89	76	4	4
	89	77	4	4
	89	77	5	5
	89	76	5	5
	90	76	5	5

Well	Position			
P-9	I	J	K1	K2
Perforation	86	94	21	21
	86	94	22	22
	86	95	22	22
	86	96	22	22
	88	98	21	21
	88	98	20	20
	89	98	20	20
	89	98	19	19
	89	98	18	18
	89	99	18	18
	89	99	17	17
	90	99	17	17
	90	99	16	16

Well	Position			
P-11	I	J	K1	K2
Perforation	88	68	33	33
	88	67	33	33
	87	65	35	35
	87	65	37	37
	87	64	38	38
	87	64	39	39
	87	64	40	40
	87	63	39	39
	87	62	38	38
	86	62	39	39
	86	61	39	39
	86	60	41	41
	86	59	41	41

Well	Position			
P-12	I	J	K1	K2
Perforation	90	71	16	16
	88	80	21	21
	89	80	20	20
	93	76	14	14
	93	76	13	13
	90	71	17	17
	89	80	21	21
	88	80	22	22
	92	77	15	15
	93	76	15	15
	88	70	23	23
	94	76	13	13
	94	75	13	13
	88	82	35	35
	88	82	34	34
	88	78	36	36
	88	76	38	38
	88	75	38	38
	89	74	33	33
	88	77	37	37
	90	73	30	30
	90	73	29	29
	90	73	31	31
	89	74	36	36
	88	75	39	39
	90	73	32	32

Well	Position			
P-14	I	J	K1	K2
Perforation	89	60	6	6
	89	59	6	6
	89	58	6	6
	89	57	6	6
	89	57	5	5
	89	57	4	4
	89	56	4	4
	89	56	3	3
	89	56	2	2
	89	55	2	2
	89	55	1	1
	90	54	1	1
	90	53	1	1
	90	53	2	2
	90	52	2	2
	90	52	3	3
	90	52	4	4
	89	52	4	4
	89	51	4	4
	89	51	5	5
	89	51	6	6
	88	57	5	5
	88	57	6	6

Well	Position			
P-15	I	J	K1	K2
Perforation	87	86	7	7
	87	87	7	7
	87	88	7	7
	87	88	8	8
	87	86	8	8
	88	86	8	8
	88	86	7	7

Well	Position			
P-21	I	J	K1	K2
Perforation	90	76	4	4
	90	77	4	4
	90	78	4	4
	90	79	4	4
	90	79	5	5
	90	80	5	5
	90	81	5	5
	89	81	5	5

Well	Position			
P-18	I	J	K1	K2
Perforation	88	96	30	30
	88	97	30	30
	88	96	31	31
	88	95	31	31
	88	94	31	31
	89	92	31	31
	89	91	31	31
	89	90	31	31
	89	90	30	30
	89	91	30	30
	89	92	30	30
	89	100	29	29
	89	93	32	32
	89	92	32	32
	89	89	30	30
	88	94	32	32
	89	88	30	30
	88	95	32	32
	84	99	51	51
	89	100	31	31
	89	100	30	30
	84	97	51	51
	85	96	49	49
	89	93	33	33
	84	98	51	51
	88	96	32	32
	87	90	37	37

Well	Position			
P-19	I	J	K1	K2
Perforation	87	82	5	5
	87	82	6	6
	87	82	8	8
	88	83	14	14
	88	83	15	15
	88	84	15	15
	89	84	15	15
	89	85	15	15
	89	86	15	15
	89	87	15	15
	89	87	14	14
	89	86	14	14
	89	88	15	15
	89	88	16	16
	90	88	16	16
	90	89	16	16
	90	90	16	16
	90	90	17	17
	91	90	17	17
	91	91	17	17
	91	91	16	16
	91	91	15	15
	91	91	14	14
	92	91	14	14
	92	92	14	14

Well	Position			
P-20	I	J	K1	K2
Perforation	85	61	39	39
	85	61	40	40
	85	61	41	41
	86	61	39	39
	86	62	37	37
	86	62	36	36
	86	62	35	35
	86	66	35	35
	87	66	35	35
	87	67	35	35
	87	67	36	36
	87	70	37	37
	87	74	38	38
	87	73	38	38
	86	64	33	33
	86	63	32	32
	86	62	32	32

Injection wells:

Well	Position			
INJ-1	I	J	K1	K2
Perforation	67	62	29	29
	67	62	30	30
	67	62	31	31
	67	62	32	32
	67	62	33	33
	67	62	34	34
	67	62	35	35
	67	62	36	36
	67	62	37	37
	67	62	38	38
	67	62	39	39

Well	Position			
INJ-2	I	J	K1	K2
Perforation	71	69	7	7
	71	69	8	8
	71	70	8	8
	71	70	9	9
	71	70	10	10
	71	70	11	11
	71	70	12	12
	72	71	26	26
	72	71	27	27
	72	71	29	29
	73	71	29	29
	73	71	30	30

Well	Position			
INJ-3	I	J	K1	K2
Perforation	78	73	33	33
	77	73	33	33
	77	73	32	32
	77	74	32	32
	77	74	31	31

Well	Position			
INJ-4	I	J	K1	K2
Perforation	100	56	40	40
	100	57	40	40
	100	58	40	40
	100	59	40	40
	100	60	40	40
	100	61	40	40
	100	62	40	40
	100	63	40	40
	100	64	40	40
	100	65	40	40
	100	66	40	40
	100	67	40	40
	100	68	40	40
	100	69	40	40
	100	70	40	40
	100	71	40	40
	100	72	40	40
	100	73	40	40
	100	74	40	40
	100	75	40	40

Well	Position			
INJ-5	I	J	K1	K2
Perforation	100	98	40	40
	100	97	40	40
	100	96	40	40
	100	95	40	40
	100	94	40	40
	100	93	40	40
	100	92	40	40
	100	91	40	40
	100	90	40	40
	100	89	40	40
	100	88	40	40
	100	87	40	40
	100	86	40	40
	100	85	40	40
	100	84	40	40
	100	83	40	40
	100	82	40	40
	100	81	40	40
	100	80	40	40
	100	79	40	40

Well	Position			
INJ-6	I	J	K1	K2
Perforation	68	90	29	29
	68	90	30	30
	68	90	31	31
	68	90	32	32
	68	90	33	33
	68	90	34	34
	68	90	35	35
	68	90	36	36
	68	90	37	37
	68	90	38	38

Appendix E
Production forecasting of Beta Brent reservoir

(Base case)

Well production rates:

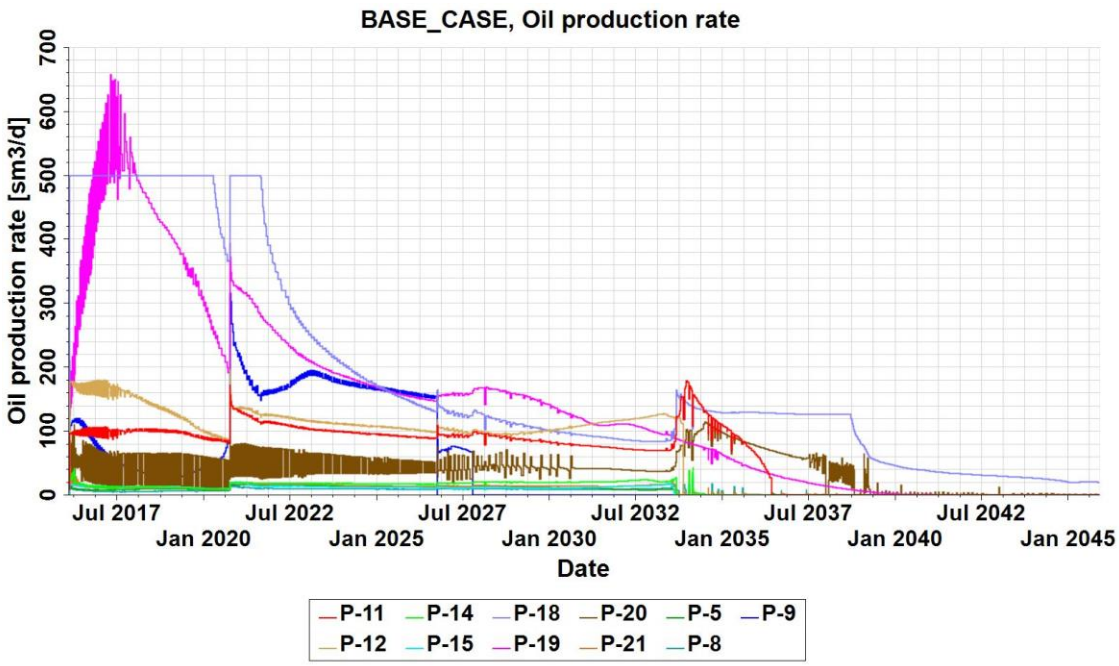


Figure 38: Base case; well oil production rates.

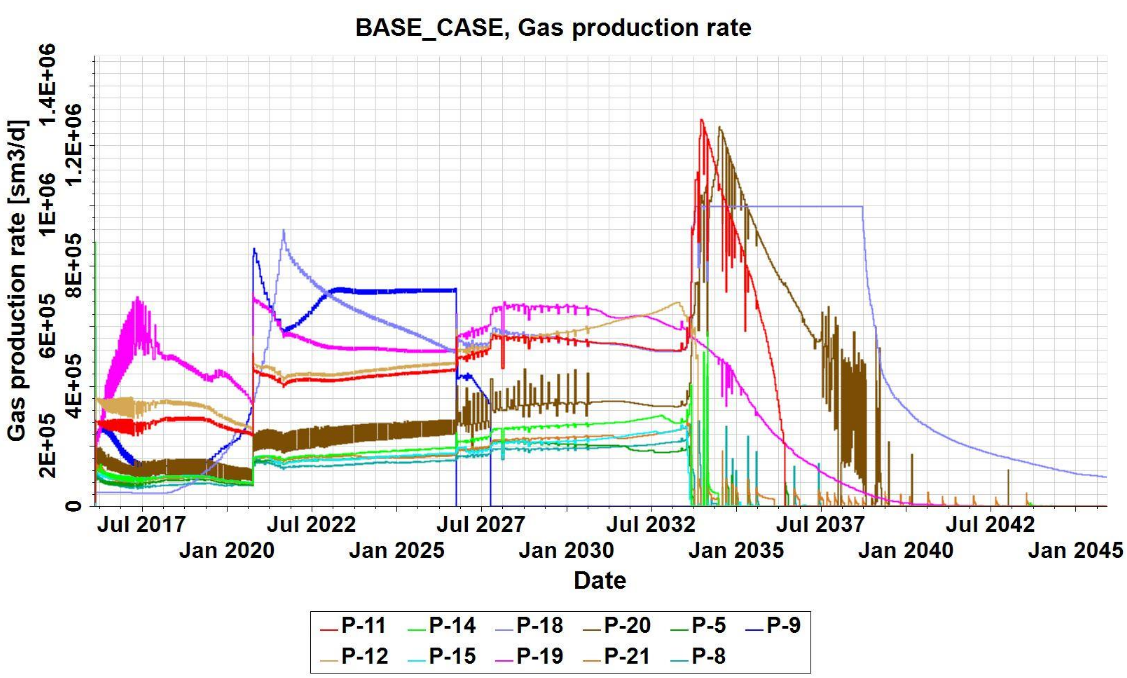


Figure 39: Base case; well gas production rates.

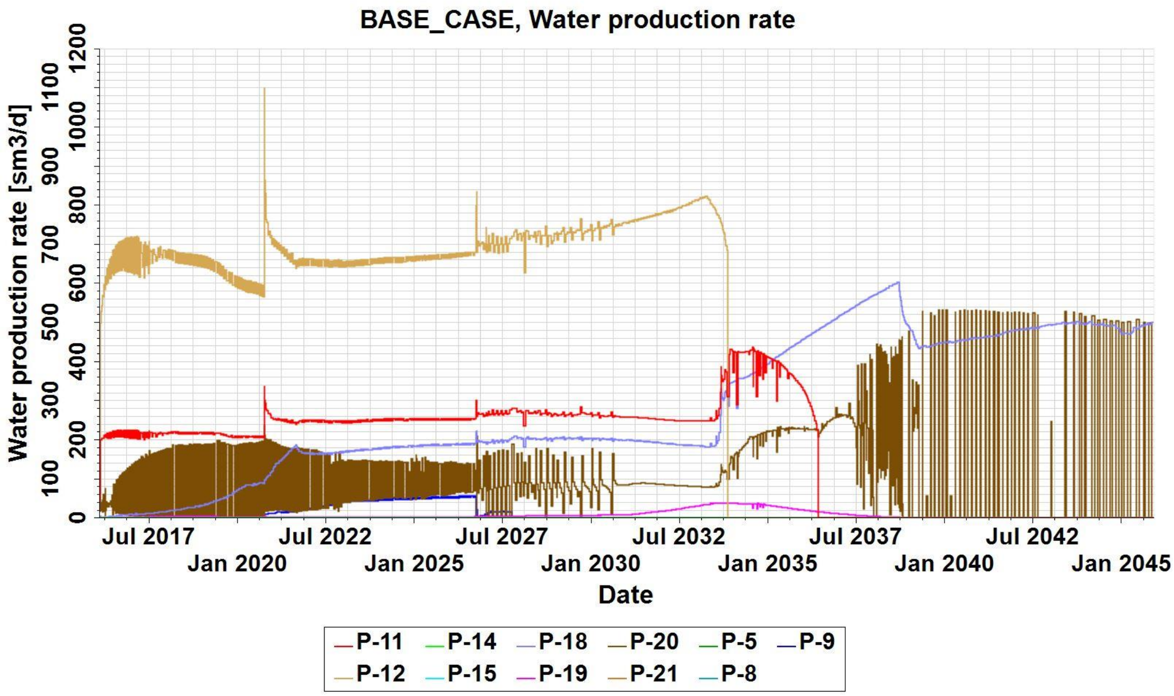


Figure 40: Base case; well water production rates

Gas-Oil Ratio and Water Cut:

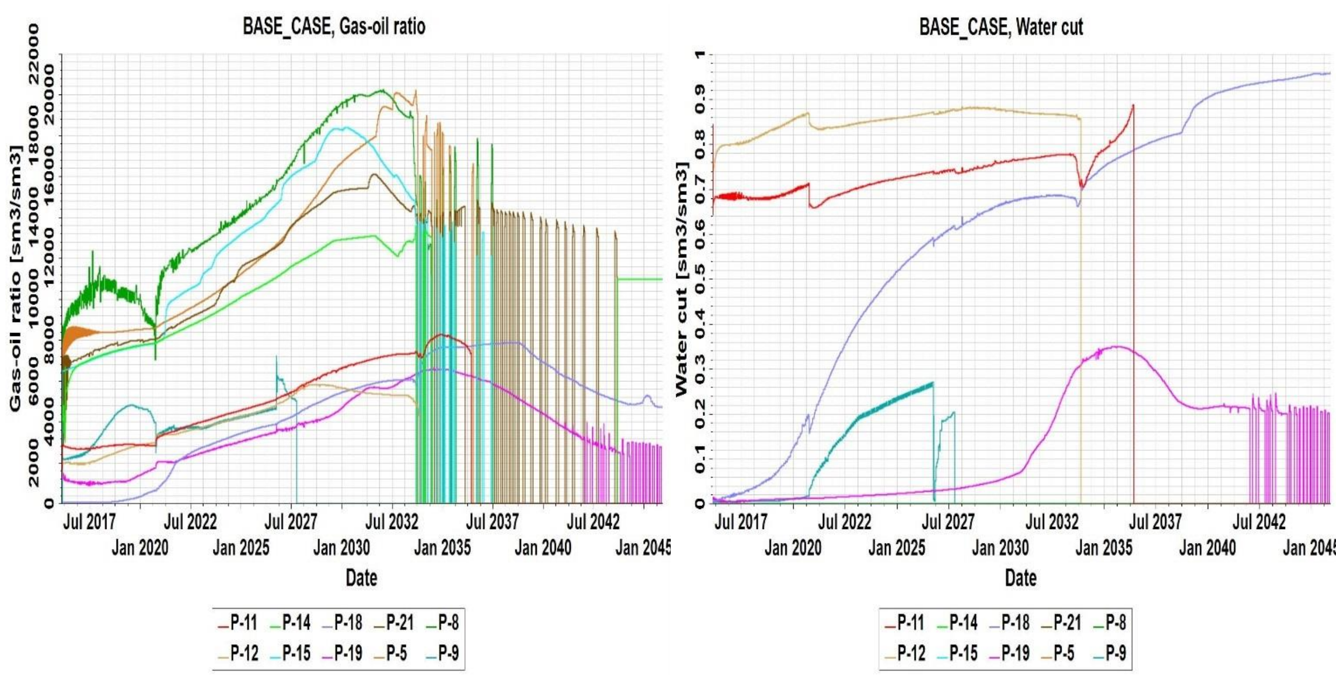


Figure 41: Base case; reservoir well gas-oil ratio (left), well water cut (right)

(Base case_2)

Well production rates:

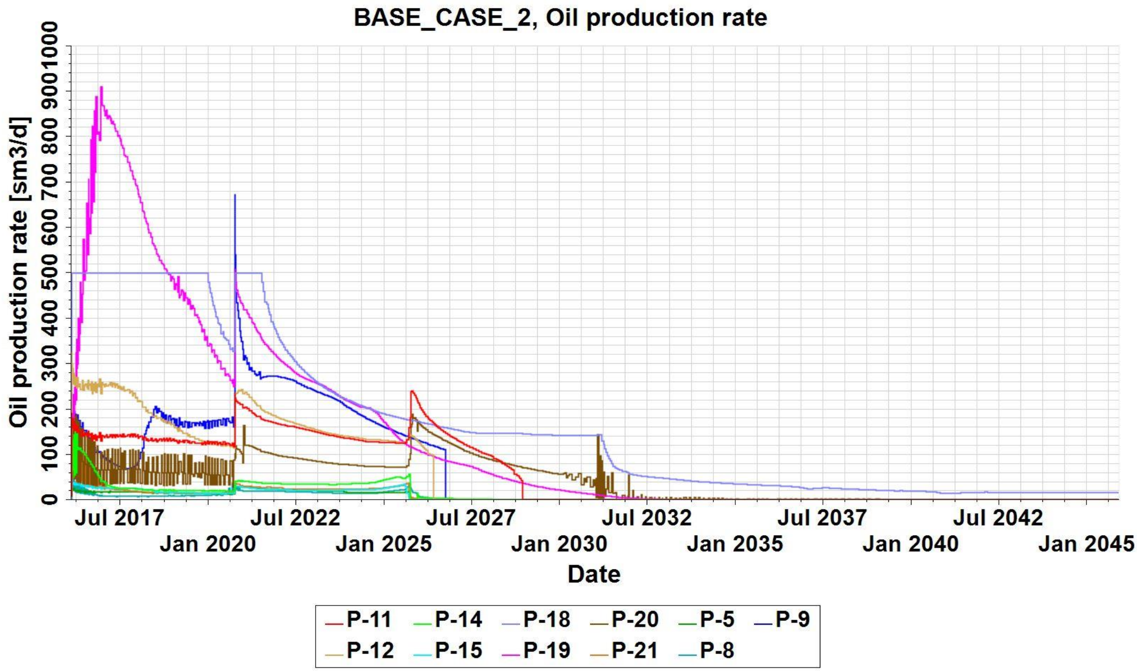


Figure 42: Base case 2; well oil production rates.

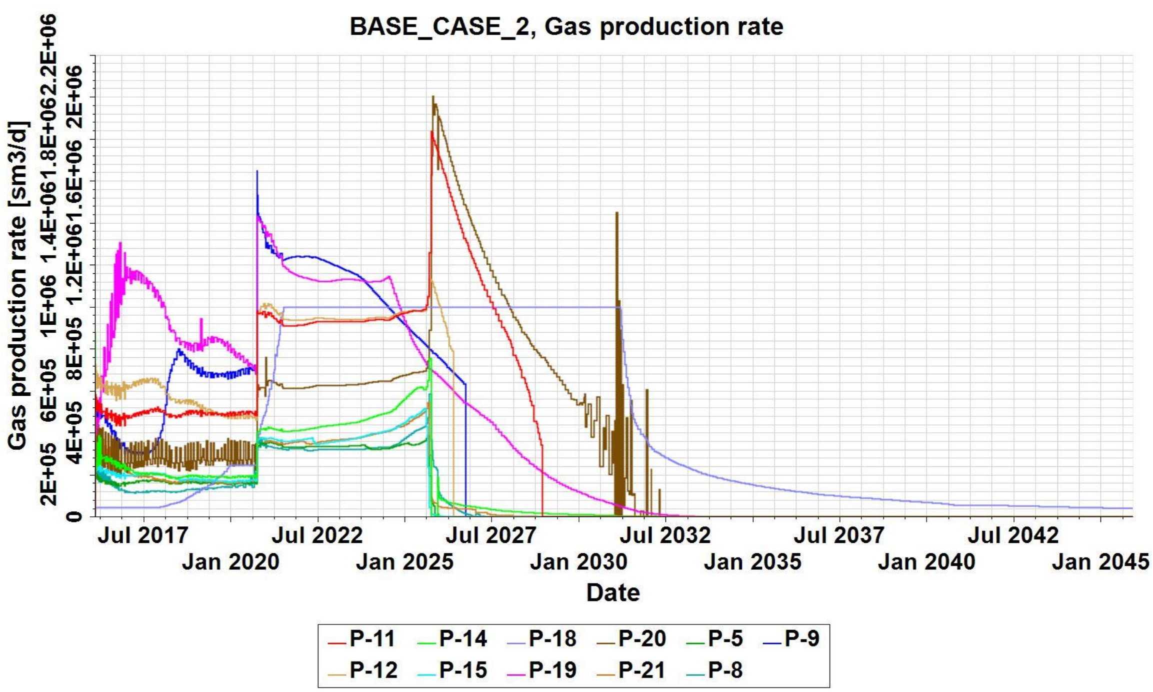


Figure 43: Base case 2; well gas production rates.

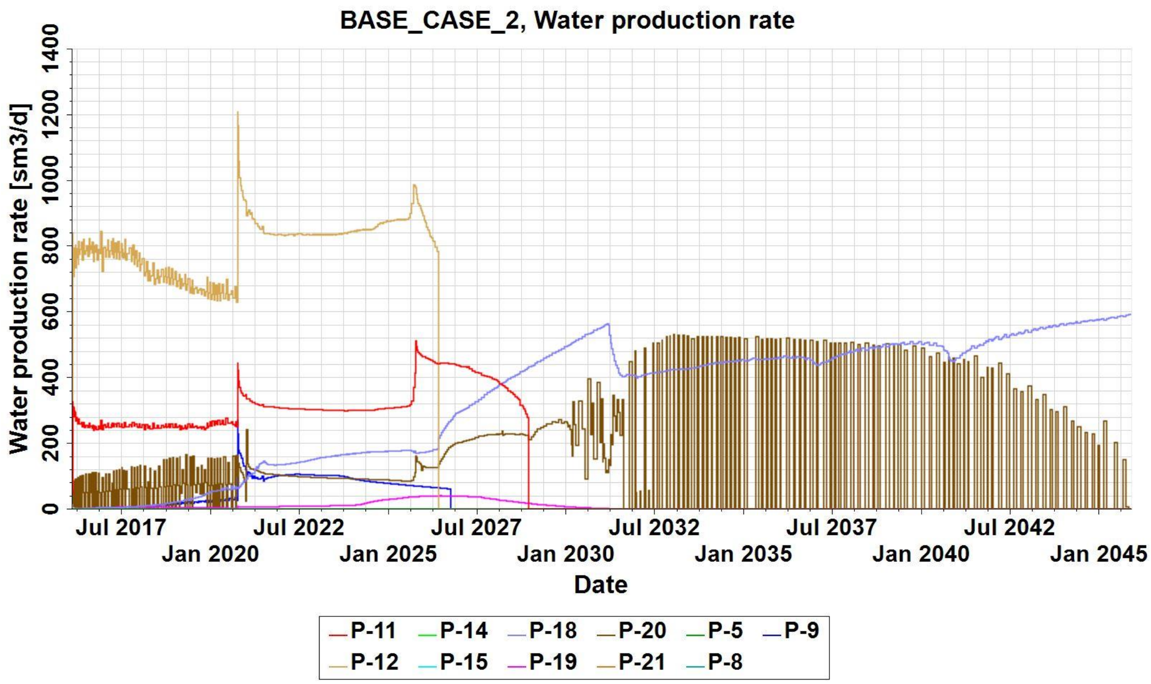


Figure 44: Base case 2; well water production rates

Gas-Oil Ratio and Water Cut:

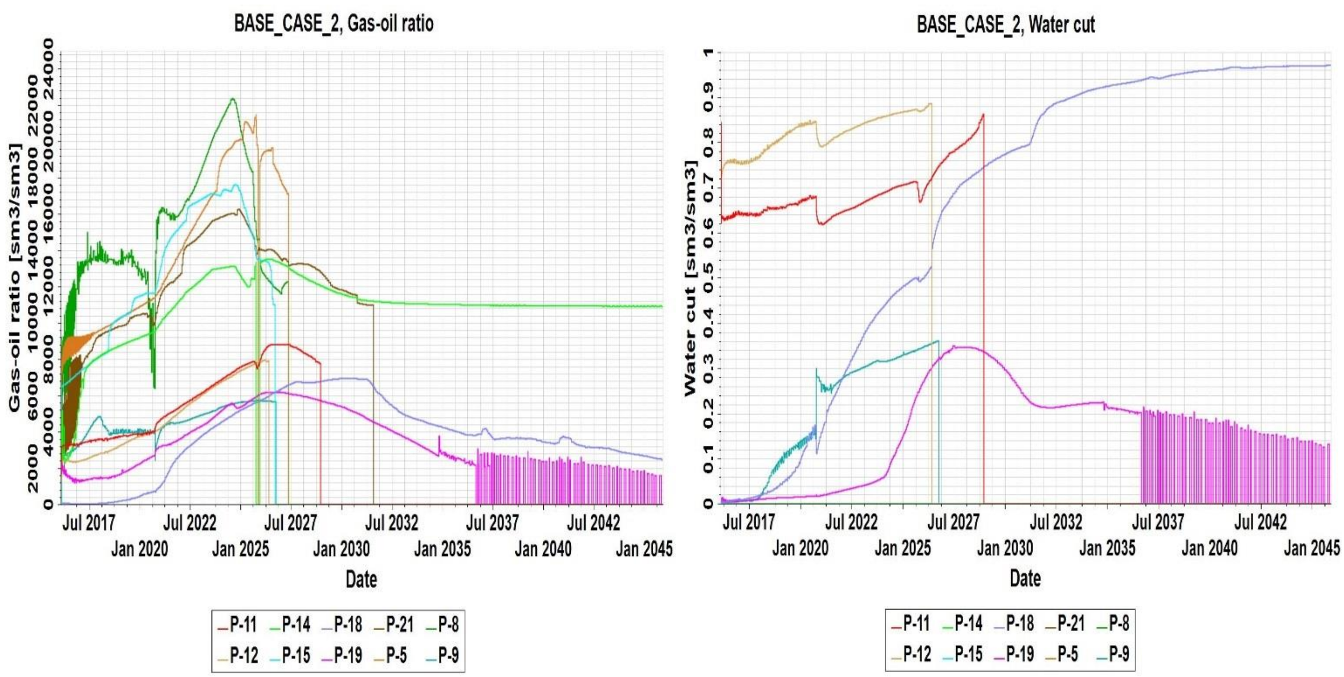


Figure 45: Base case 2; reservoir well gas-oil ratio (left), well water cut (right)

(Base case_3)

Well production rates:

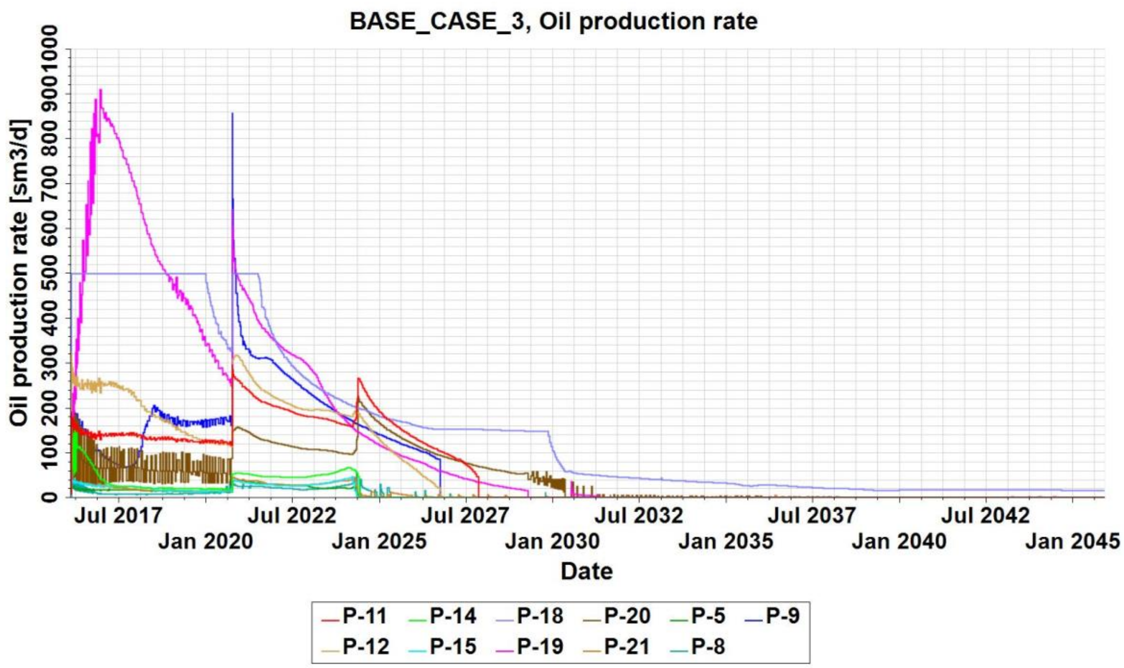


Figure 46: Base case 3 (Scenario-1) ; well oil production rates.

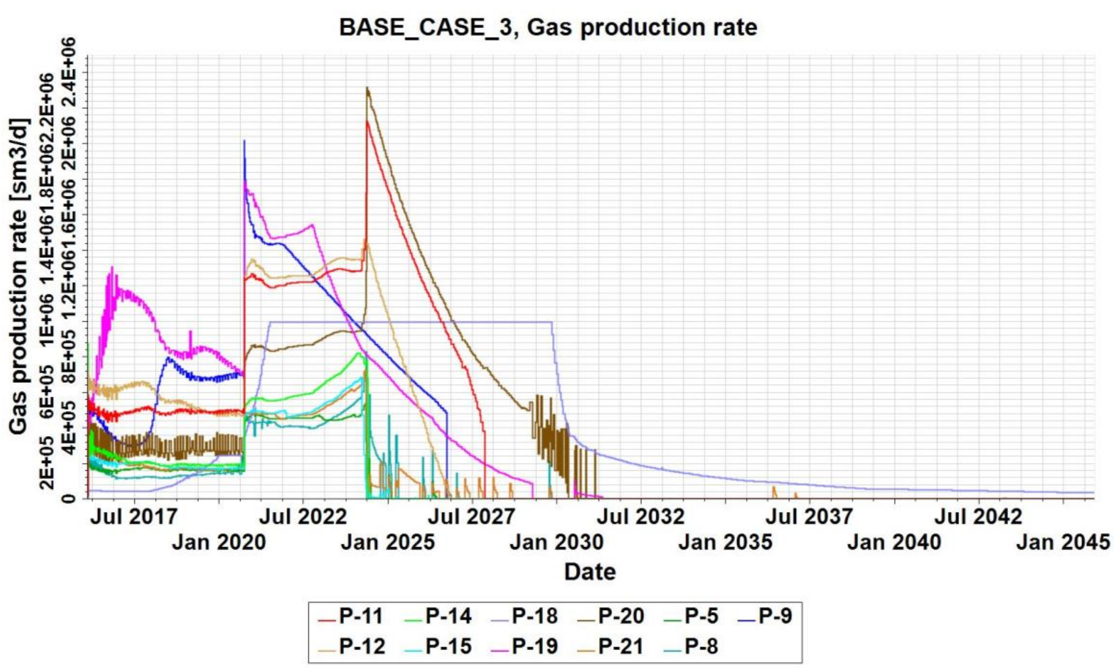


Figure 47: Base case 3 (Scenario-1); well gas production rates.

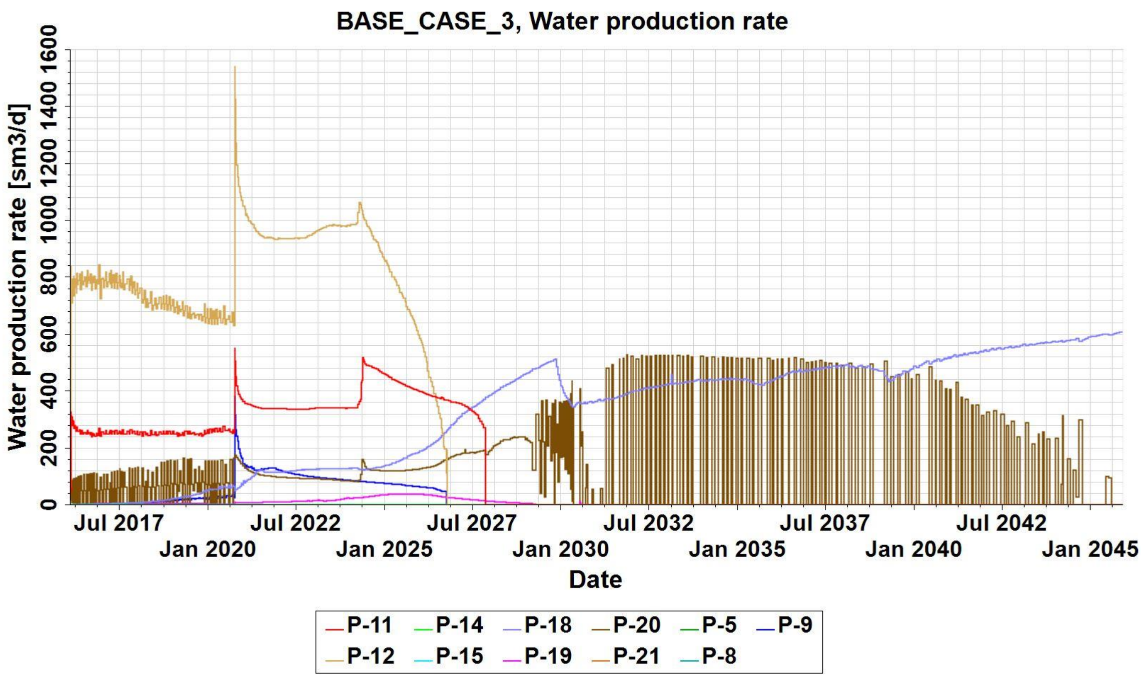


Figure 48: Base case 3 (Scenario-1); well water production rates

Gas-Oil Ratio and Water Cut:

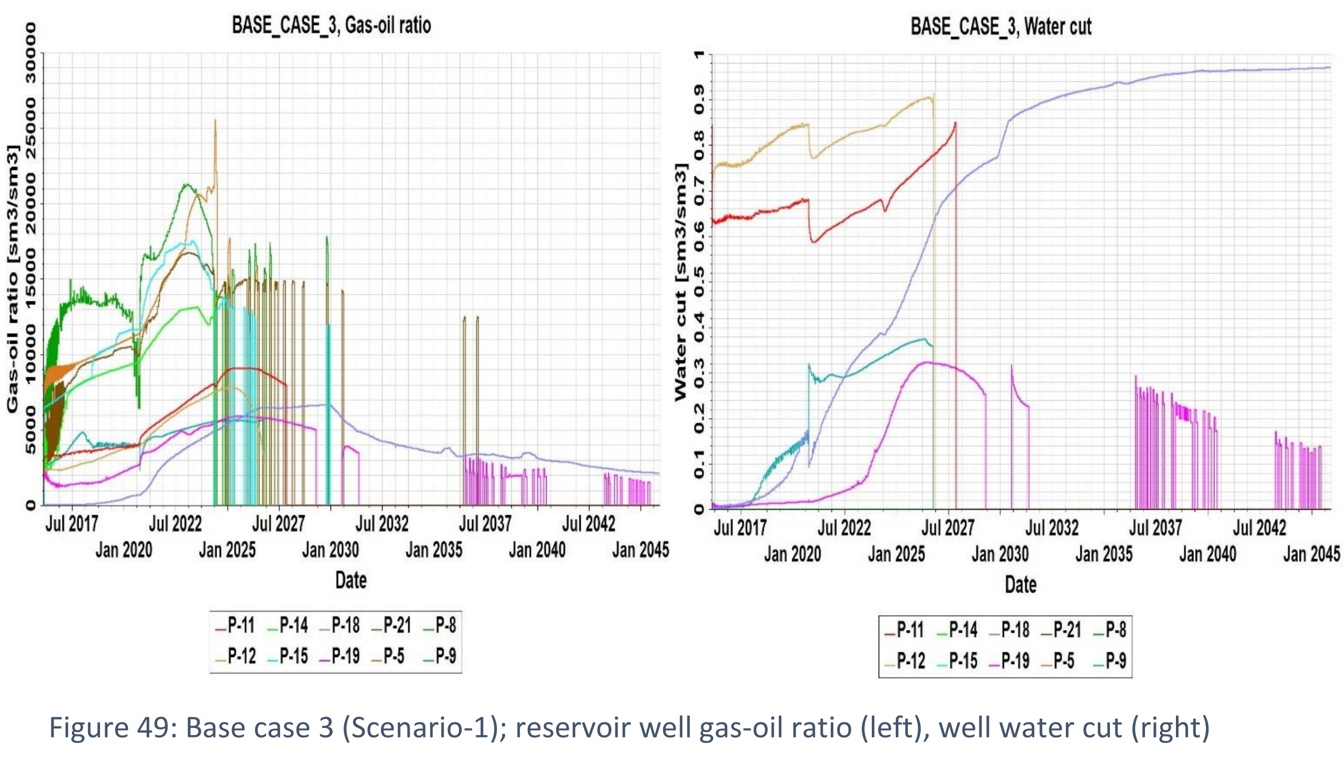


Figure 49: Base case 3 (Scenario-1); reservoir well gas-oil ratio (left), well water cut (right)

(Base case_4)

Well production rates:

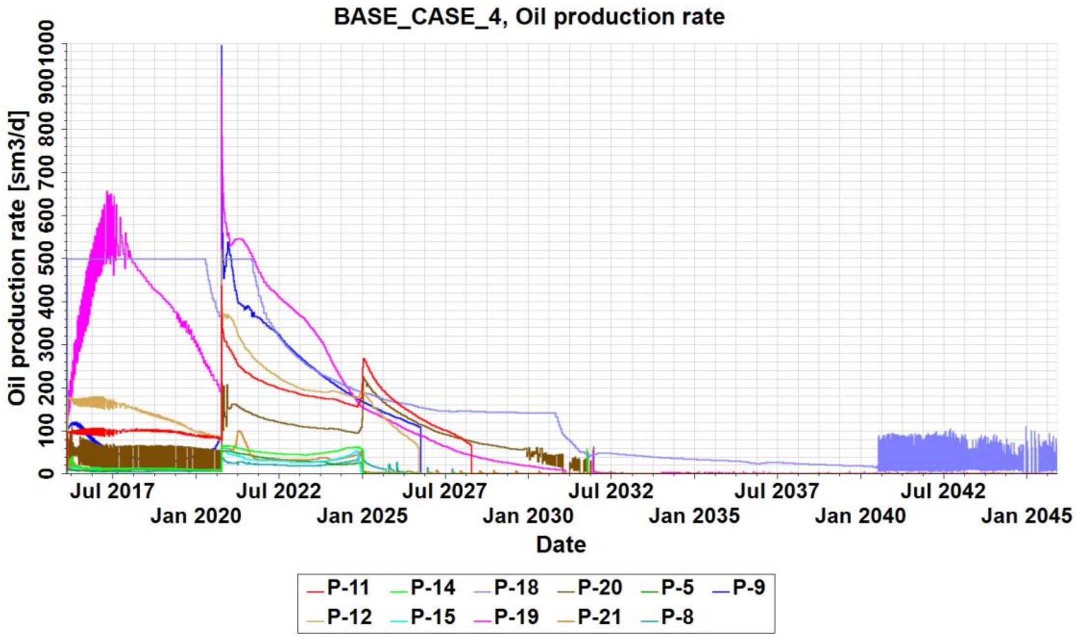


Figure 50: Base case 4; well oil production rates.

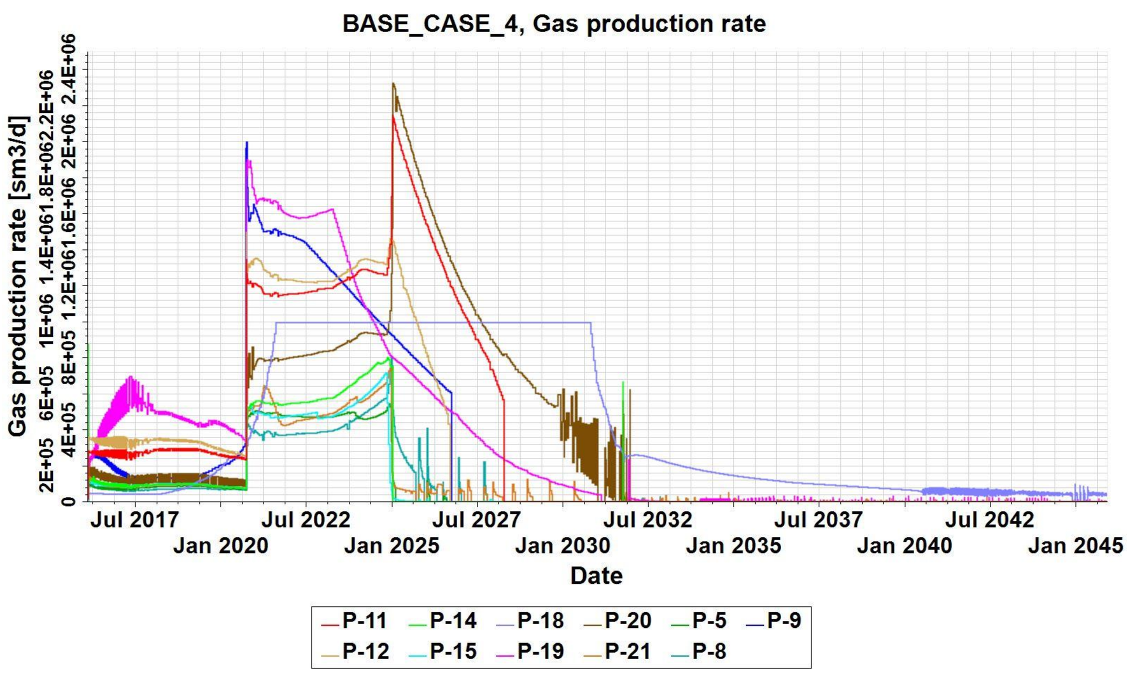


Figure 51: Base case 4; well gas production rates.

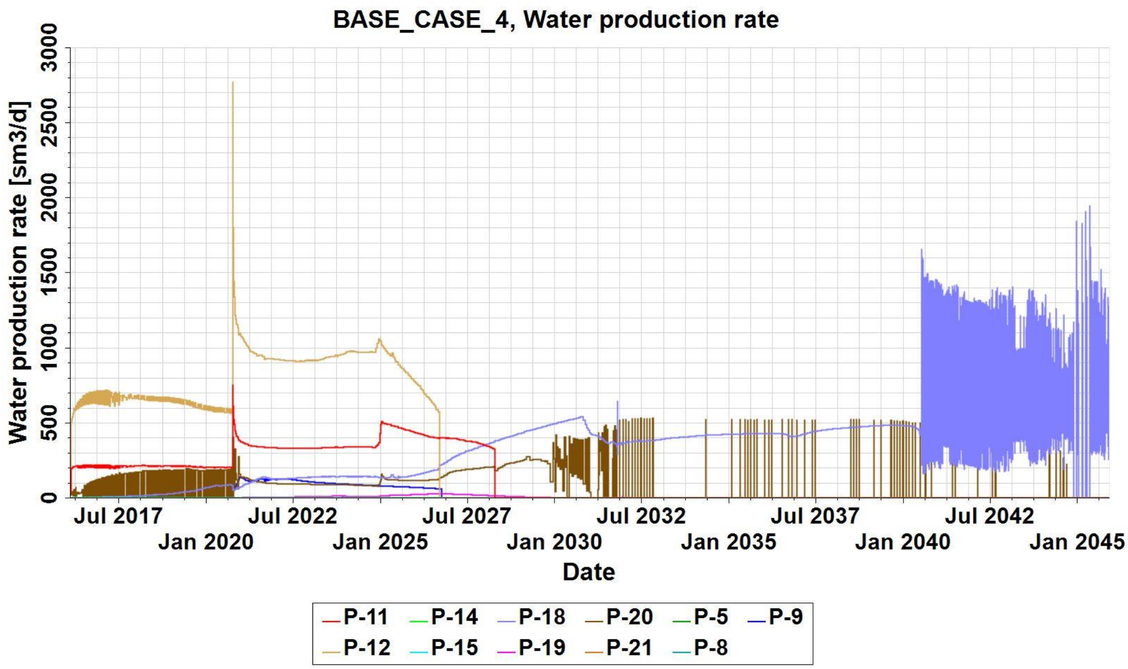


Figure 52: Base case 4; well water production rates

Gas-Oil Ratio and Water Cut:

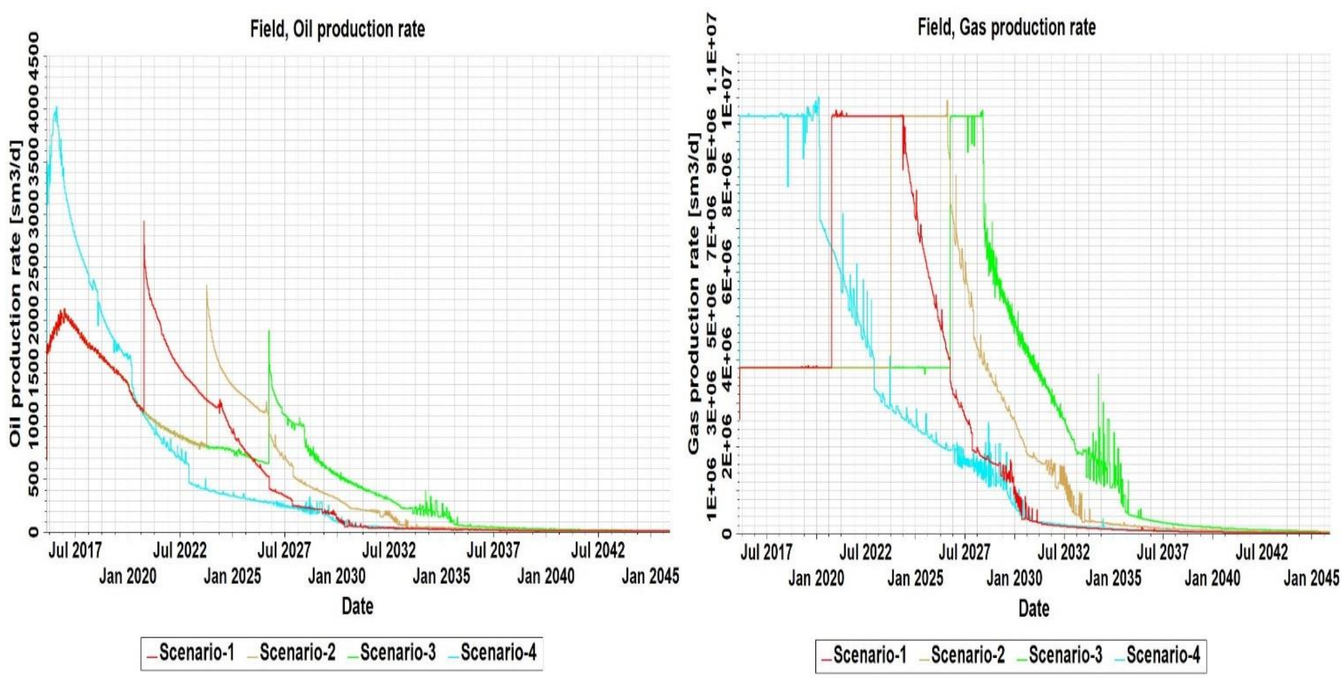


Figure 53: Base case 4; reservoir well gas-oil ratio (left), well water cut (right)

Appendix F
Production forecasting of gas export scenarios

(Scenario-1: Base_Case_3)

The production profiles of Scenario-1 have already been illustrated in Appendix E (Base case_3)

(Scenario-2: BETA_2016-2023)

Well production rates:

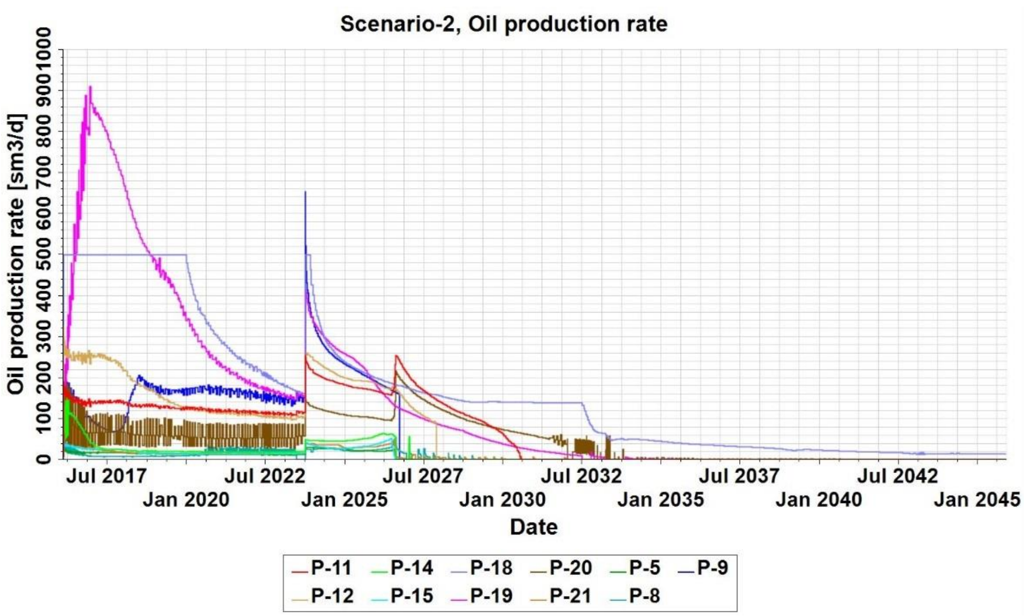


Figure 54: Scenario-2; well oil production rates.

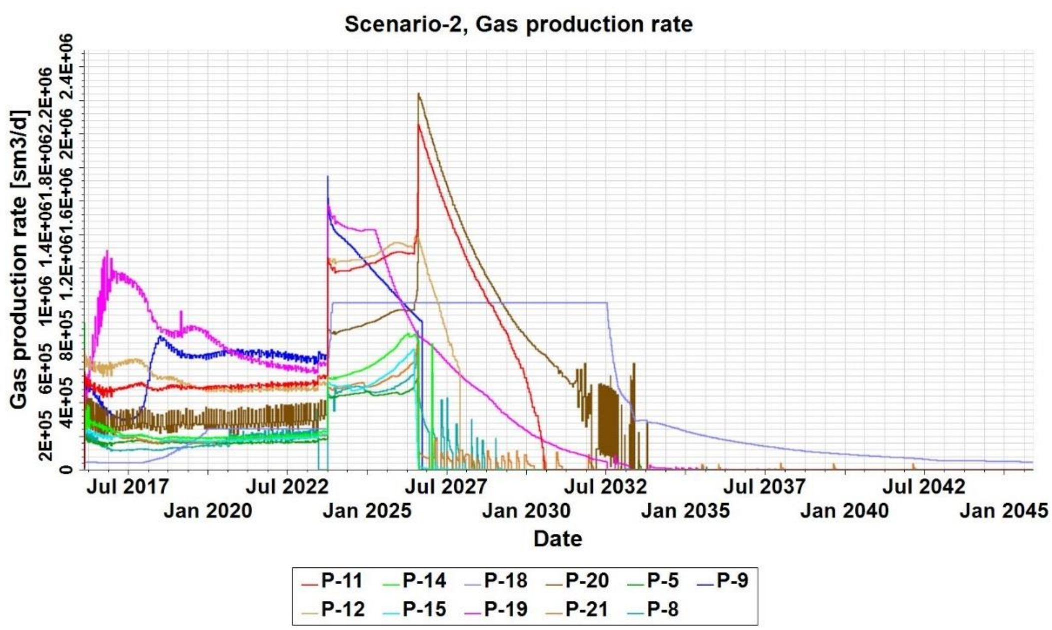


Figure 55: Scenario-2; well gas production rates.

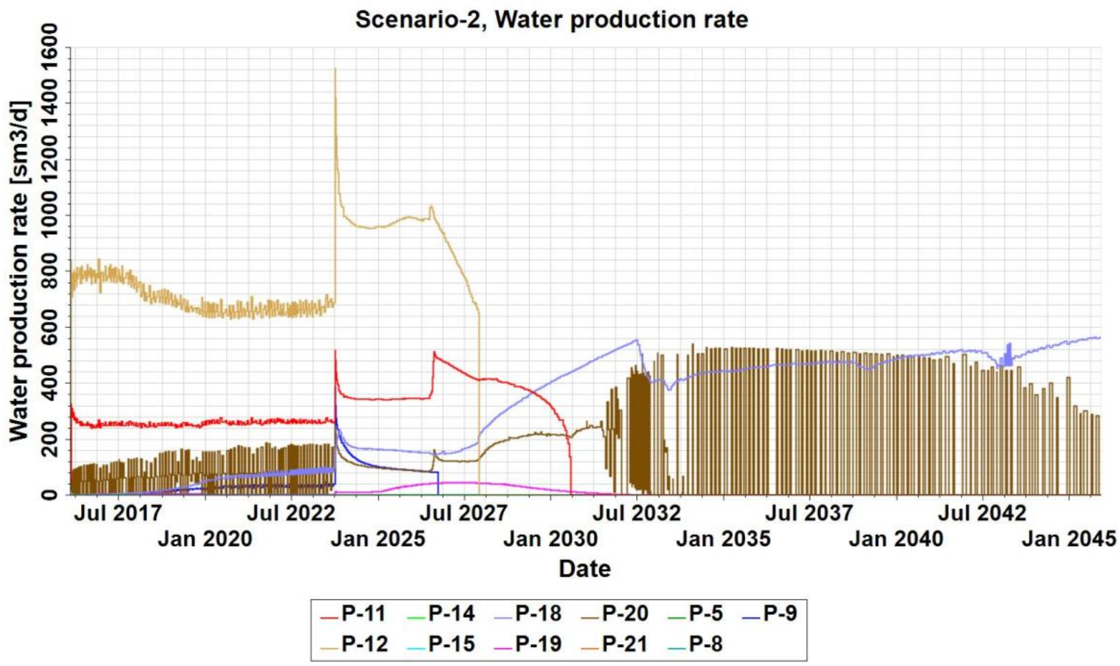
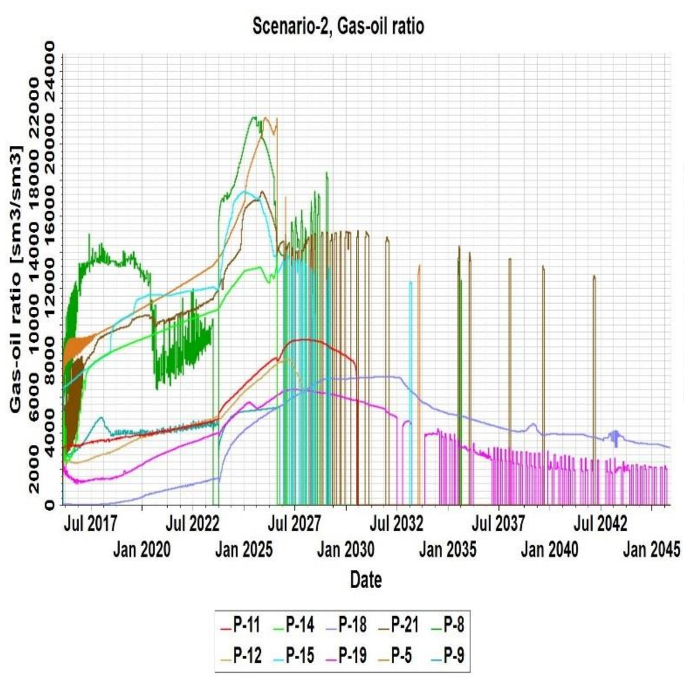


Figure 56: Scenario-2; well water production rates

Gas-Oil Ratio and Water Cut:



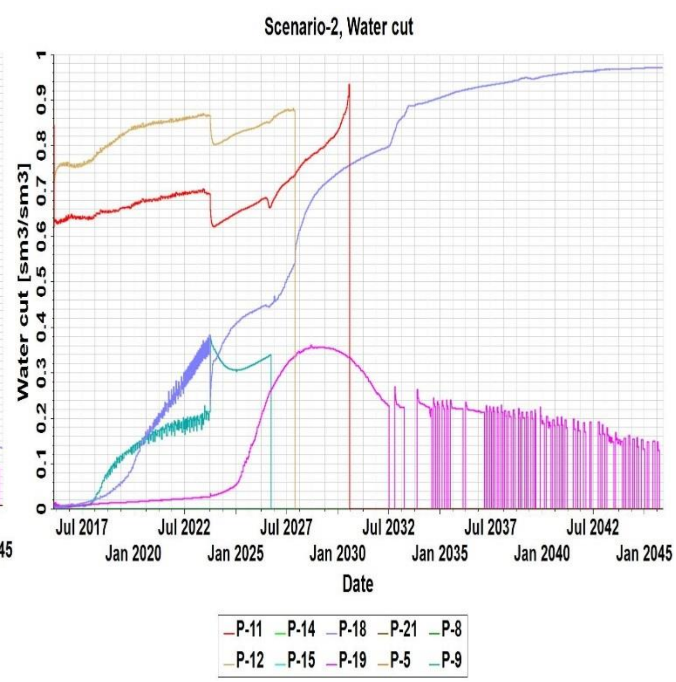


Figure 57: Scenario-2; reservoir well gas-oil ratio (left), well water cut (right)

(Scenario-3: BETA_2016-2026)

Well production rates:

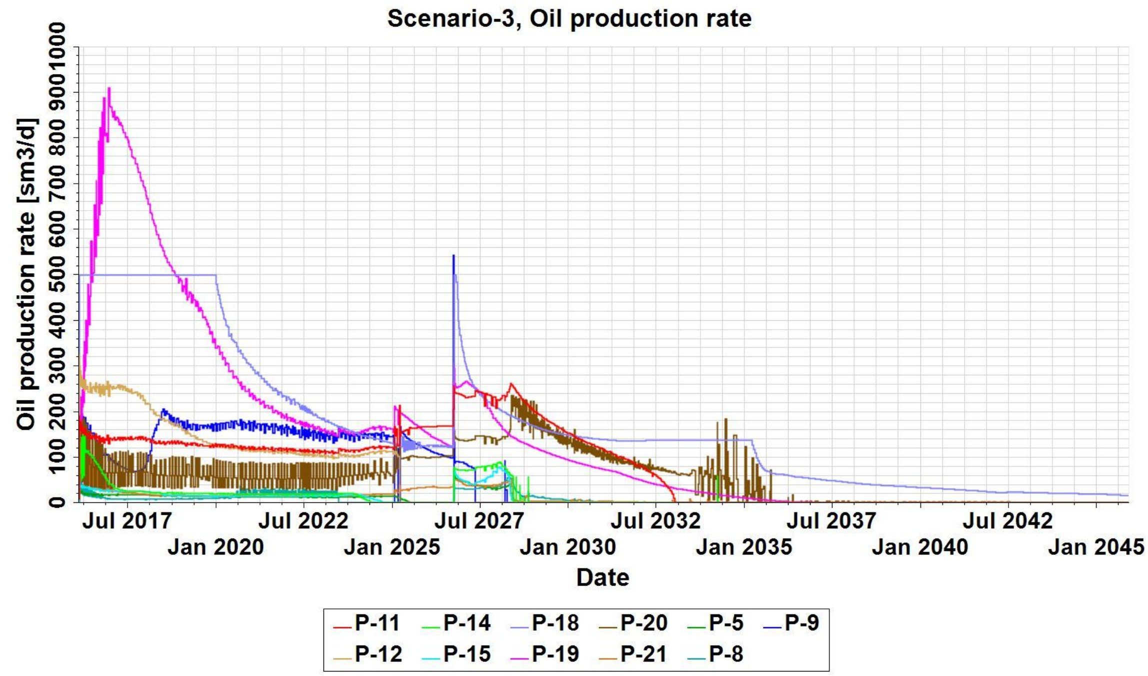


Figure 58: Scenario-3; well oil production rates.

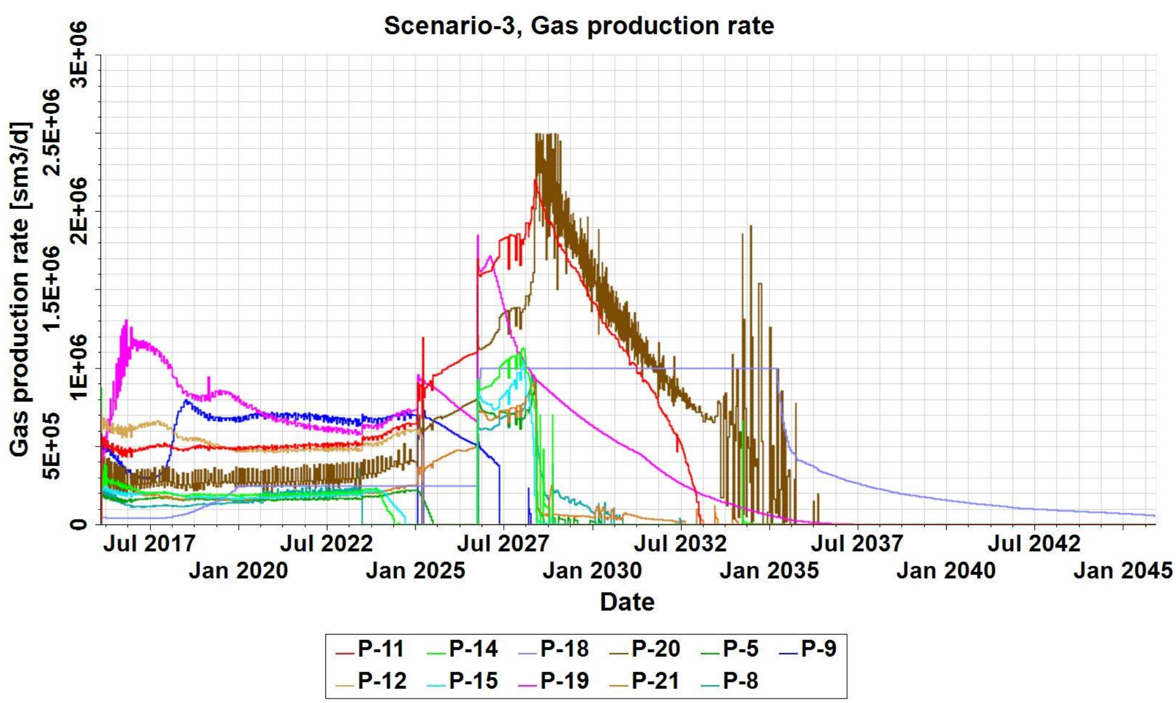


Figure 59: Scenario-3; well gas production rates.

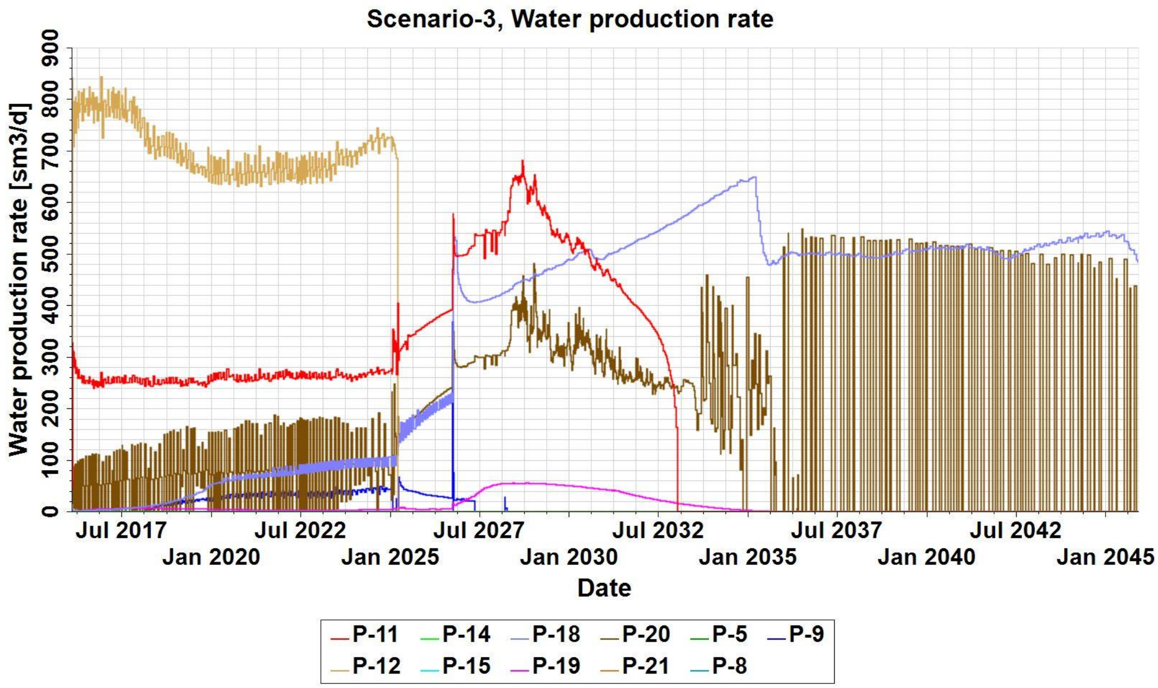
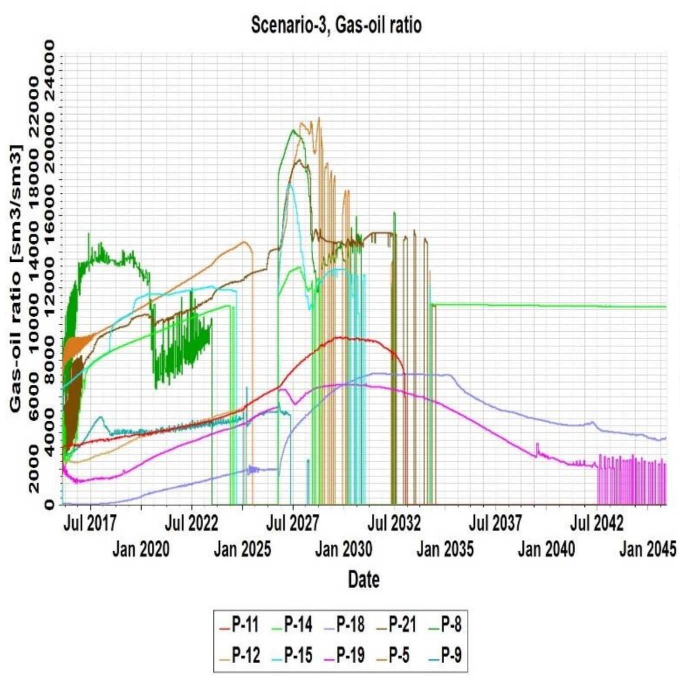


Figure 60: Scenario-3; well water production rates

Gas-Oil Ratio and Water Cut:



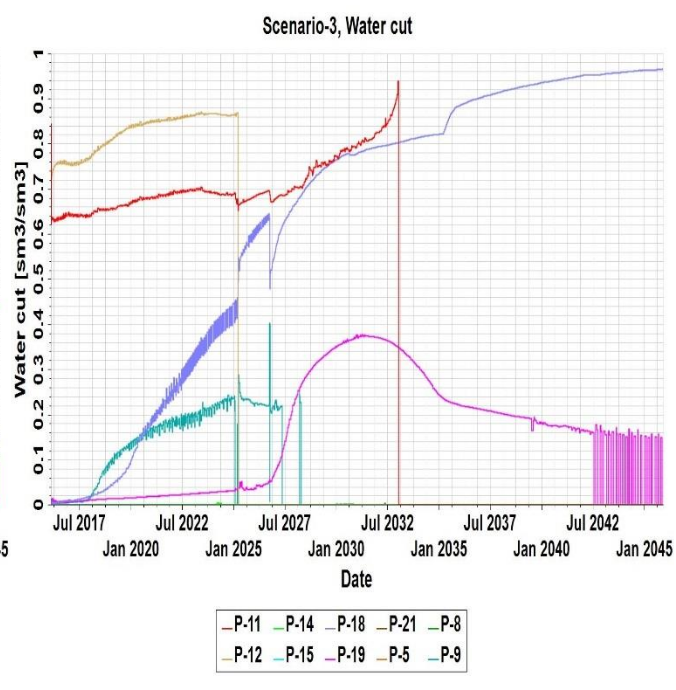


Figure 61: Scenario-3; reservoir well gas-oil ratio (left), well water cut (right)

(Scenario-4: BETA_GAS_EXPORT_2016)

Well production rates:

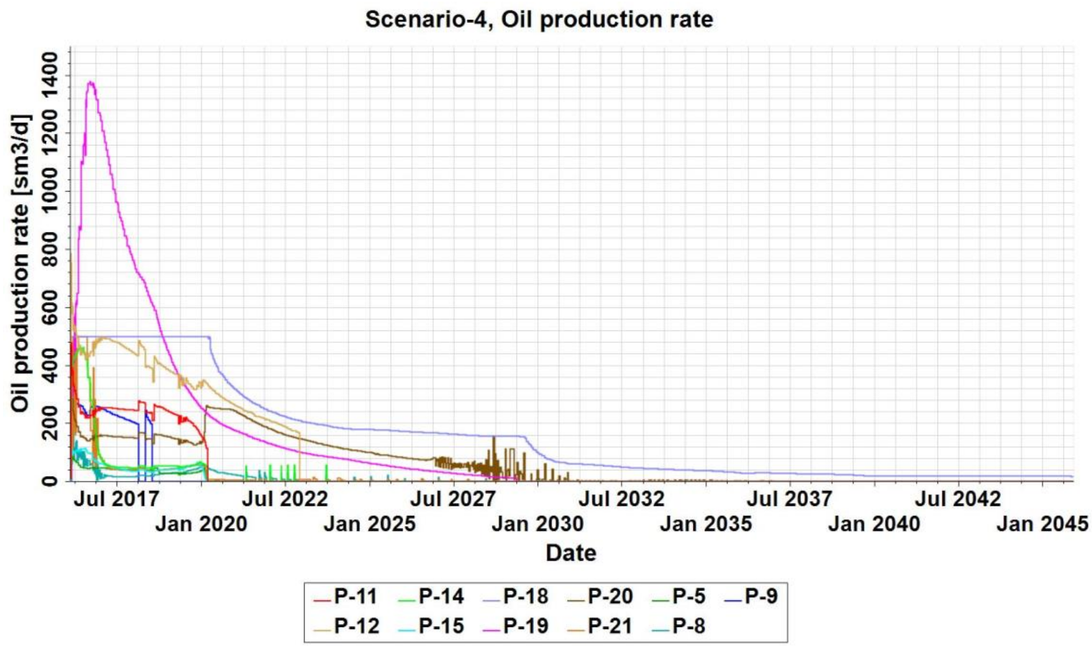


Figure 62: Scenario-4; well oil production rates.

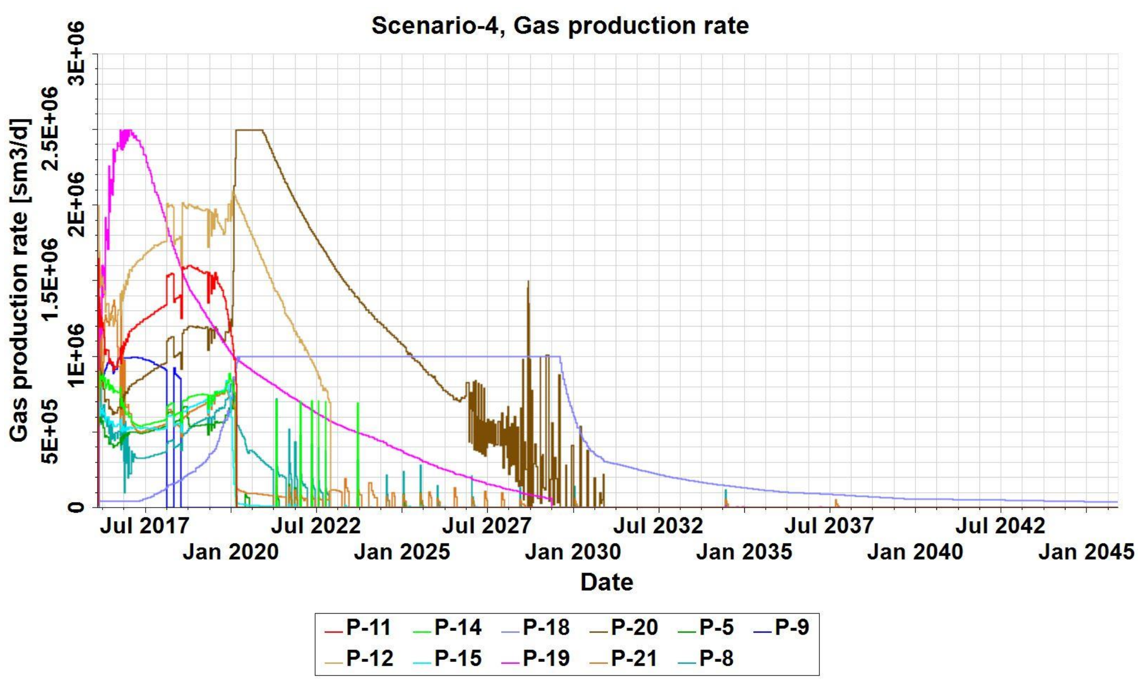


Figure 63: Scenario-4; well gas production rates.

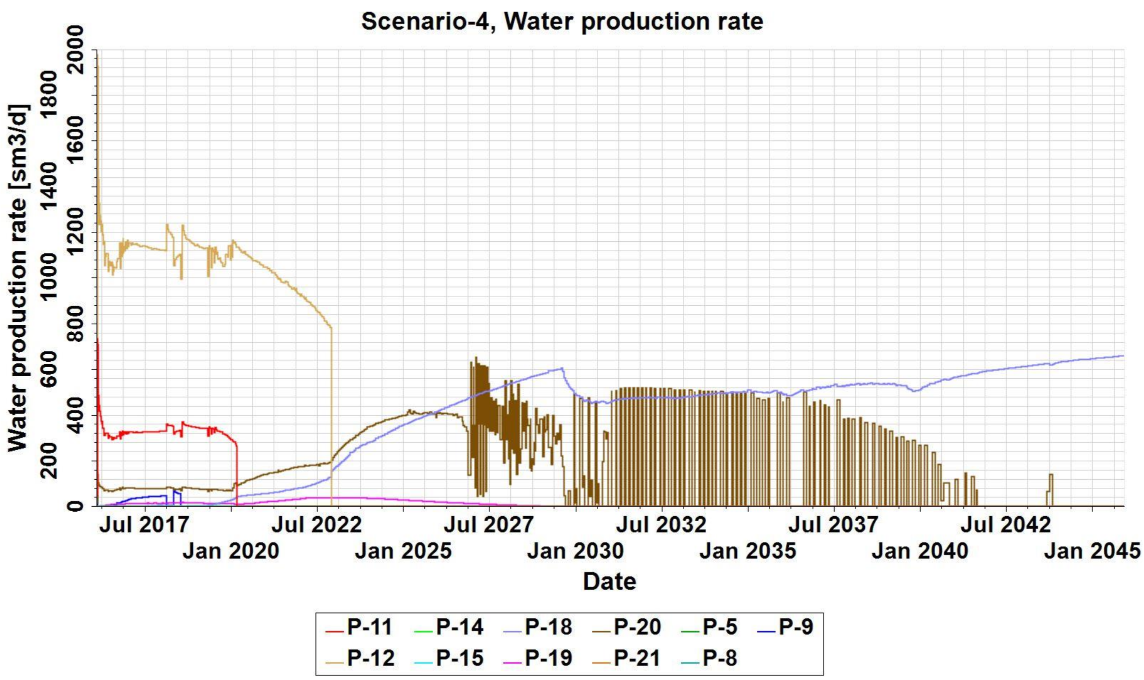


Figure 64: Scenario-4; well water production rates

Gas-Oil Ratio and Water Cut:

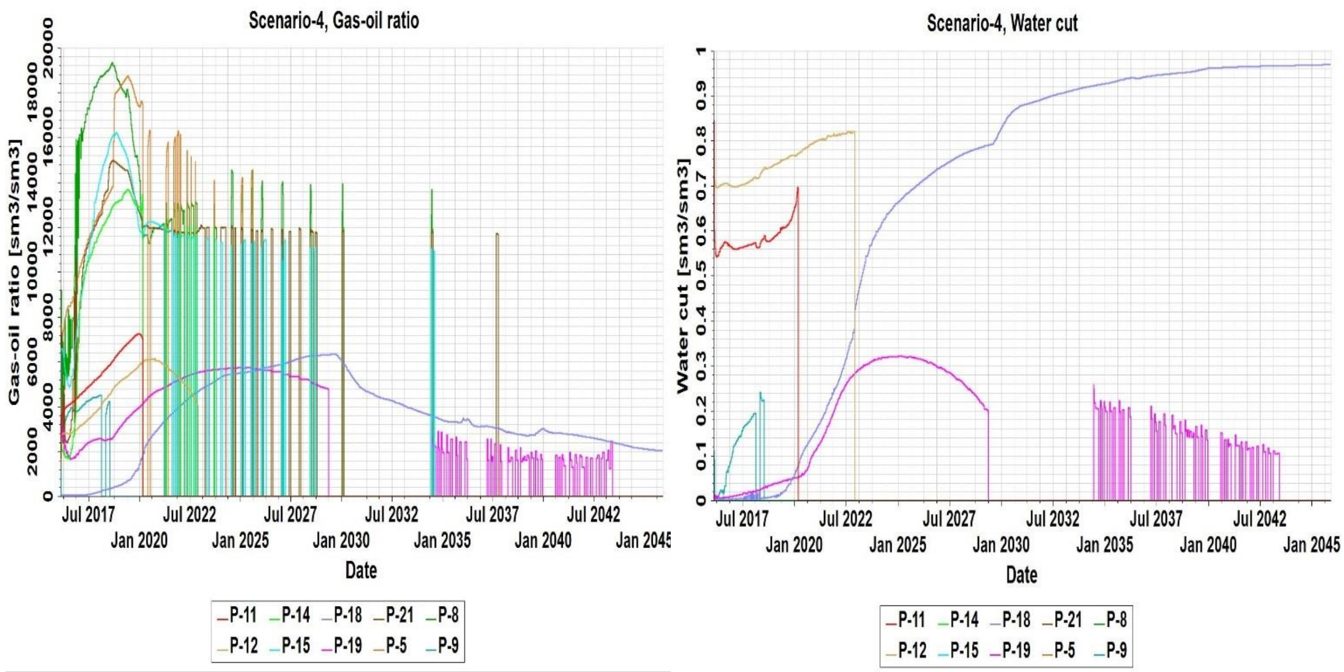


Figure 65: Scenario-4; reservoir well gas-oil ratio (left), well water cut (right)