EXPERTS IN TEAMWORK
GULLFAKS VILLAGE 2010

GROUP 3

Technical Report

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Preface

Experts in Teamwork (EiT) is a compulsory course for all Master's degrees and professional studies at NTNU. Students work in groups of five or six students from several different disciplines. EiT is organized in "villages" which consist of around thirty students. All the faculties offer villages and the students can chose between them. The village is characterized through a broad interdisciplinary topic. At the end of the semester the students shall submit a report, consisting of two parts, one technical part and one process part. The objective of Experts in Teamwork is to encourage students to apply their academic learning and develop their teamwork skills. During the work in this course the students have the opportunity to test their ability in working in a team and to improve their cooperation with others. This teamwork enables each student to receive training in the application of their field of expertise in practice, which furthermore leads to an improvement of their own academic skills. All the group members have tried to fulfil their responsibilities in the best way in order to reach the group goal. The group would like to thank the advisers and facilitators from Statoil, the village chief Jon Kleppe, Jan Ivar Jensen and the student assistants, Ida Emilia Sareneva and Daniel Aleksander for the effective help and encouragements.

Abstract

This report is written as a result of the work being done by group 3 in Gullfaks Village 2010. The goal of the village is improved recovery on Gullfaks Sør Statfjord. This technical report consists of two parts, Part A and Part B.

An Eclipse reservoir simulation model was run to simulate two different cases in part A, a reference case and an extended case. In the extended case two injection wells and four producers was added to the reference case. Of the producer wells, three should be two-branched wells, and one single-branched. There were two possible expansion options; a new drilling platform at Gullfaks Sør, or a subsea solution. The simulation showed that the recovery factor increased, but so did also the gas-oil ratio. Based on the economic evaluation, the platform solution is the most profitable. It is beneficial in the best case, but it is not, and even less beneficial than the subsea solution in the worst case. This means that it is all a question of risk.

The challenge in part B was to improve the recovery using smart wells. A five-branched well and Inflow Control Devices were used in the model. The Eclipse reservoir simulation model was also used to simulate this part. The drilling and productions option were the same as in part A, a fixed platform or a subsea solution. The results were mixed. A more stable oil production rate was observed compared to the extended case, but the production rate was lower until 2020. The economic analysis for the five-branched well resulted in negative revenue for both alternatives. The main reason for this is the high cost of the gas that has to be bought.

Content

1 Introduction

Fields, discoveries and prospects in the Gullfaks area are shown in Figure 1. The area comprises nine production licences. The red line in the figure divides the area into two parts: the Gullfaks field (Gullfaks/GF) and the Gullfaks satellites (Gullfaks SAT/GF SAT). Gullfaks SAT consist of Gullfaks South, Rimfaks, Gullveig, Skinfaks and Gulltopp. The Gullfaks Satellite Fields all lay on separate, westward rotated fault blocks in the southern part of the Tampen area to the west and south of the Gullfaks Field. The pre-Cretaceous structure is the result of two different rift phases – one Permian-Triassic and one late Jurassic-early Cretaceous. The structuring during the first phase partly controlled the development of the structural pattern during the latter phase. The area is dominated by late Jurassic–early Cretaceous rift-phase developments.

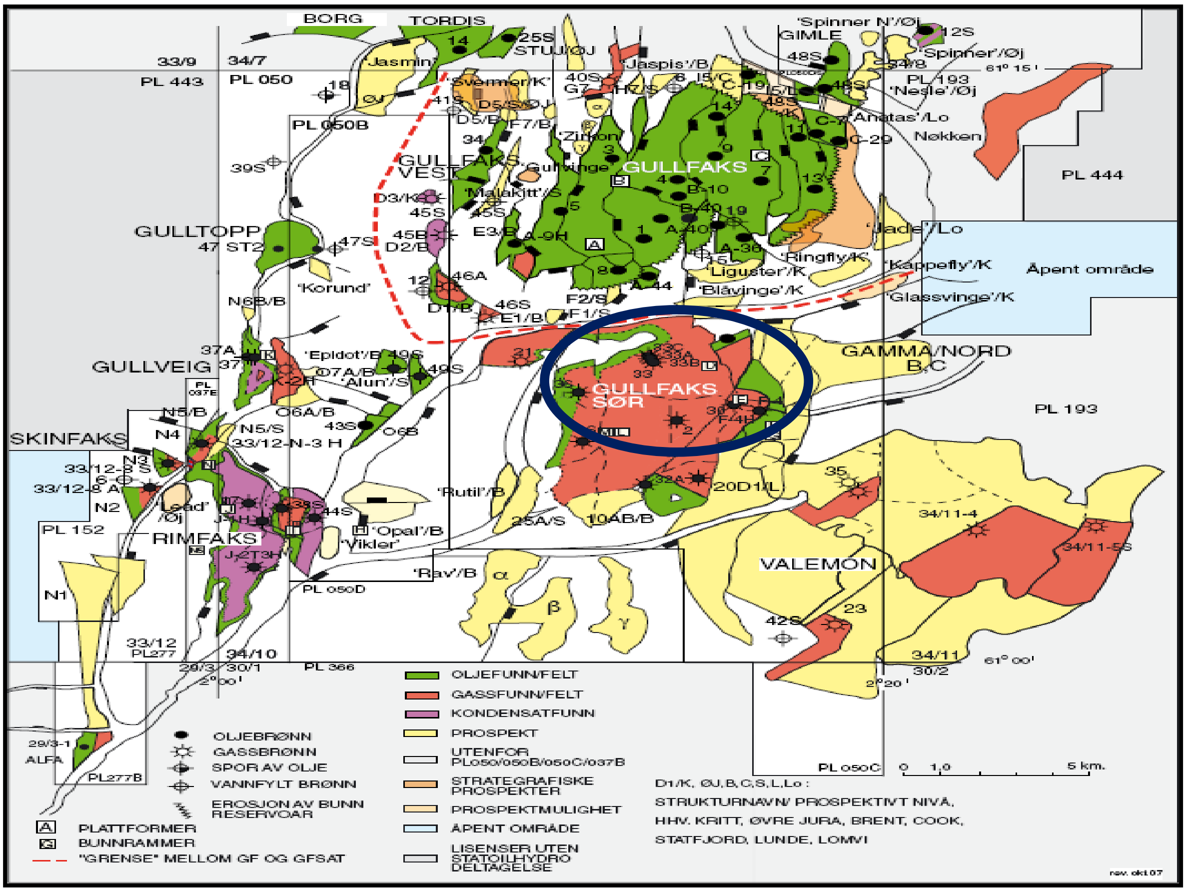


Figure 1: Field, discoveries and prospects (Statoil, Gullfaks Village 2010 IOR from Gullfaks Sør Statfjord, 2010).

2 Stractural Geology of Gullfaks Area

2.1 Gullfaks Main Field

The Gullfaks Field lies to the west of the Viking Graben, and constitutes a structural high point in the Tampen area. The field comprises a number of rotated fault blocks, containing mainly pre-, but also syn-rift sediments as young as late Jurassic to early Cretaceous in age and is divided into three main structural domains (Figs. 2). The central and western areas of the field consist of a domino system of westerly dipping rotated fault blocks. A nonrotated horst complex lies farthest to the east. Between these two areas lies a complex accommodation area, characterised by a fragmented antiformal fold structure. The structural architecture of Gullfaks is mainly the result of late Jurassic-early Cretaceous rifting, although earlier rift structures of Permian-Triassic age probably influenced the later structural development to some degree (Fossen & Hesthammer, 2005).

The field is dissected by a set of main faults which form an anatomising pattern, with a dominant north-south orientation in map view (Figure 2). These faults typically have offsets of between 50 and 250 metres, although throws of almost 500 metres are recorded. The main faults in the domino system have an eastward dip of approximately 30°. In the horst complex, the faults have a westward dip of approximately 60-65°.

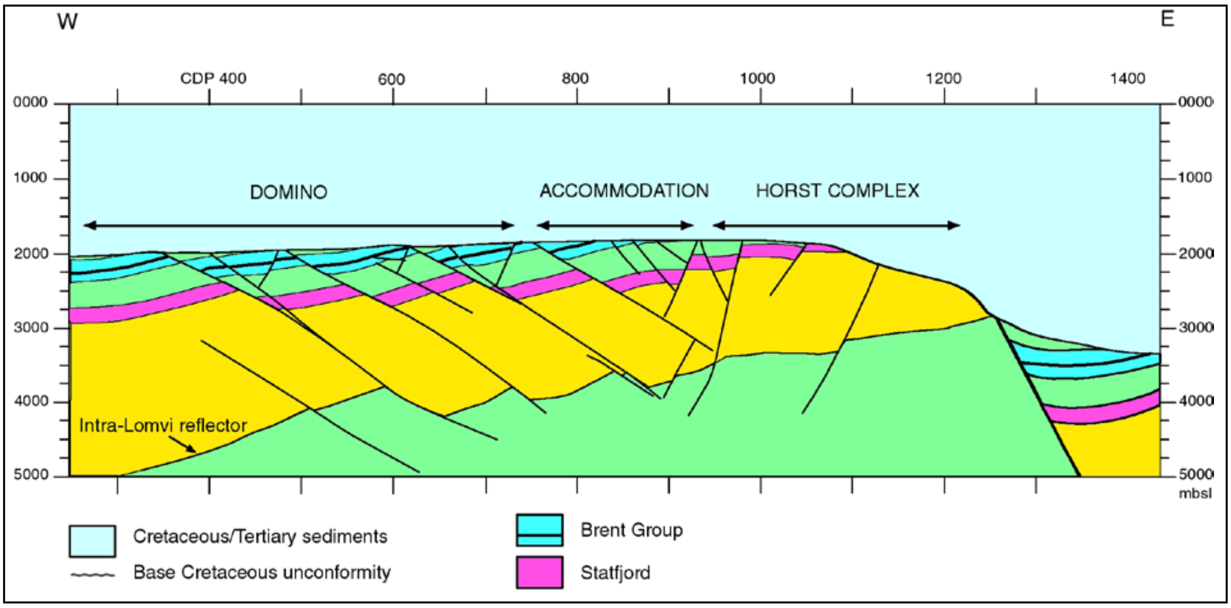


Figure 2: General Average of Gullfaks main field (Statoil, 2007).

2.2 Gullfaks South

Gullfaks South represents the deepest structural level in Gullfaks SAT, with top reservoir at 2,860 m TVD MSL. In terms of both area and total resources in place, it is clearly the largest of the four fields. The faults in Gullfaks South have dominant N-S trends, and are associated with NE-SW and E-W trending faults. The fault density tends to increase at shallower stratigraphic depths (Brent Group), containing sediments that were less consolidated at the time of deformation. The Gullfaks South structure has traditionally been divided into three structural domains from west to east: the domino system, the transitional area and the horst complex Figure 3.

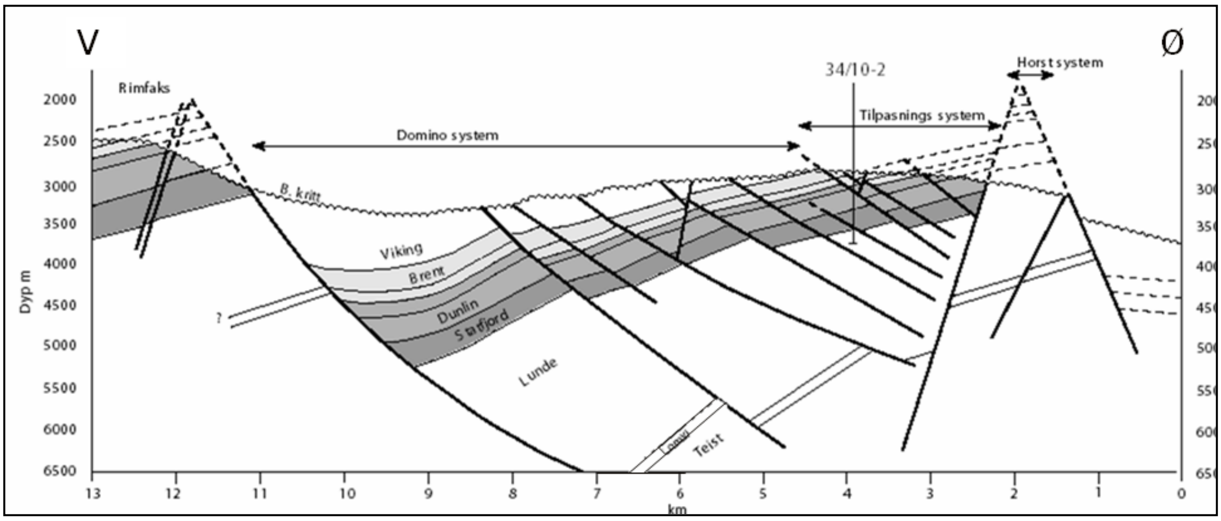


Figure 3: General cross-section of Gullfaks South (Statoil, 2007).

The Domino system

The Domino system is represented by recurring easterly dipping faults and westerly dipping layers. This is the dominating structural domain and constitutes the western and central parts of Gullfaks South.

The accommodation area

Between the Domino system and the Horst complex lays a transitional area which makes up the third structural domain on Gullfaks South. The transitional area (also referred to as the accommodation area) has a NNE-SSW orientation and is the most complex structural area.

During the fault development phase, this area must have acted as a buffer zone between the eastward-facing faults in the domino area and the westward-facing faults in the horst complex.

The Horst complex

The Horst complex makes up the eastern most part of Gullfaks South, and defines a structural crest with a NNE-SSW orientation and is delineated by easterly and westerly dipping faults.

This is also the most eroded area, mostly with Cretaceous sediments lying directly on the Triassic sediments of the Lunde Formation. Locally, up to 30 m of upper Jurassic with traces of unclean sands (34/10-F-4 H, -G-3 H) has been preserved beneath the Base Cretaceous Unconformity. The horst structure may be less deformed than the other parts of the field to the East, although the lack of good continuous seismic reflections makes this interpretation uncertain. In the east, the horst is bounded by a fault offset of more than 1,000 m. Fault seal analyses, including measurement of micro-faults in core samples, show significant reduction of fault rock permeabilities relative to the undeformed rock (Statoil, Faulting and Fault Sealing in the Gullfaks Sør field, Rapport 9802).The fault rock permeability decreases with increasing amount of phyllosilicate minerals in the reservoir. This reduction is especially pronounced for faults in the Ness and Etive Formations, due to relatively low sand thicknesses in these layers and the consequent high probability for fault offset, and restricted fluid flow can be expected. Faults in the Tarbert Formation and Rannoch Formation have higher permeabilities, as the sand layer thickness is greatest for these intervals, and the communication in these zones is expected to be less restricted for a given fault offset. Faults in the Statfjord Formation are generally dominated by low permeability fault rocks that are likely to restrict fluid flow. Good communication across faults in the Eirikson Member, where cataclasite is locally distributed, was indicated in a fault seal analysis study. Production history, however, shows that this analysis was overly optimistic: this was later confirmed by a comprehensive micro structural study of cores from Wells 34/10-2 and 34/10-30 (GF-Petek-99, 1999) .This study revealed the presence of deformation bands (containing cataclasite and framework phyllosilicate) leading to a reduction of the fault rock permeability by a factor of four relative to the undeformed rock. Obviously, this would contribute to the general poor flow characteristics of this reservoir.

2.3 Source rocks and migration in Gullfaks South

The conclusions from geochemical data and migration modelling studies are summarised below:

The fluids in Gullfaks South have been generated from a moderately mature marine Draupne Formation source rock.

- The field has primarily been filled from the east via the Lunde Formation through the Statfjord Formation to the Brent Group. The Brent Group in the Gamma structure to the East is juxtaposed against the Lunde Formation on the Gullfaks South Field across the main eastern boundary fault.
- The geochemical signature of the fluids in the western parts of Gullfaks South (Wells 34/10- 36 and 34/10-21) has a greater terrestrial kerogen source signature indicating that the fluids have received some contribution from a local kitchen area, probably in the west, which is oil-mature today.
- This kitchen also has the possibility of contributing oil to the 15AB/B and H/B prospects. The contribution from this basin will, however, be extremely limited.. The Draupne Formation in the southern part of the Viking Graben has passed beyond hydrocarbon generation today, but was oil-mature in the Palaeocene.
- The geochemical signature of the Statfjord Formation oil in Well 34/10-32R in the south of Gullfaks South indicates contribution from a local source. According to the local migration model, a local basin in the south contributes to this area – something that is positive for the prospects in Segments 10AB/B.

2.4 Reservoir Quality, Statfjord Formation, Gullfaks South

The upper Statfjord Formation interval, consisting of the Nansen Member and Eiriksson-2 unit, is approximately 70-80 m thick, while the lower Statfjord Formation interval, consisting of the Eiriksson1 unit and Raude Member, has a thickness of around 160-175 m. In a number of wells and observation boreholes, there have been clear indications of several hydrocarbon systems internally in the Statfjord Formation (Statoil, Rapport 9802).Empirical production data from Wells G-2 HT3 and F-4 AHT3 show that the reservoir pressure has decreased quite quickly and are indicative of limited communication laterally within the reservoir. This was the background to a geological study of the structure based on core material from exploration Wells 34/10-2 and 34/10-30 in the summer of 1999.The study found a number of deformation bands linked to faults and these were interpreted as the most important reason for reduced communication. The throw across the micro-faults/deformation bands is on a millimetre to centimetre scale, but dissolution and recrystalization of quartz has caused much reduced permeability across the deformation zones. In Well L-4 H (drilled during winter 1999/2000) the Statfjord Formation was found to be dry approximately 60 m above the OWC in the existing fluid model (3,362 m TVD MSL). This indicates that there are sealing faults within the Statfjord Formation and that the reservoir is significantly more complex than was originally assumed.

The assumed contacts for the Statfjord Formation at Gullfaks South are based on pressure measurements and log evaluations in Exploration Wells 34/10-2 and 34/10-30. The resistivity log in Exploration Well 34/10-32 is consistent with the same OWC. For volume calculations, we therefore assume a common GOC and OWC for most segments, even though we know that the detailed pressure picture is very complex, so that the contacts may vary locally.

In addition to the exploration wells, the Statfjord Formation has been logged in Wells F-4AHT3, G-2 H, G-2 T3H, G-3 HT2, G-1 H, G-2 Y2H, F-2 Y1H and F-2 Y2H (Figure 4).

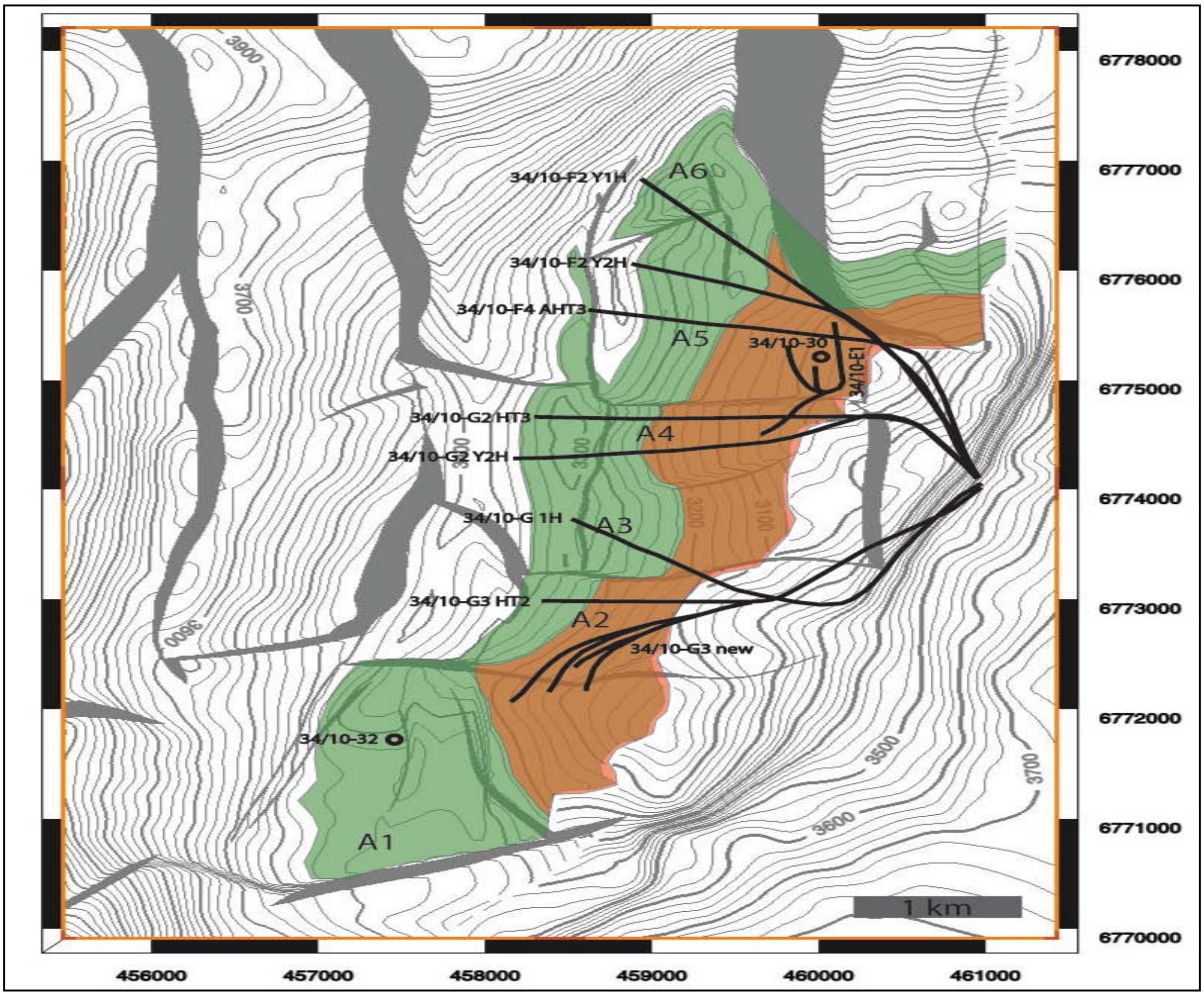


Figure 4: Distribution of the Exploration and Production Wells.

2.5 Seismic data in Gullfaks

Gullfaks is covered by a number of seismic volumes, both surface streamer seismic surveys and ocean bottom cable seismic data. The quality of the seismic data varies across the Gullfaks Field. Problems with imaging are often related to carbonate-cemented sands in the Hordaland Group and gas leakages. There are also areas of significantly reduced reflectivity associated with the near surface sediments deposited along the Norwegian Trench. A map showing the extent of these deposits, and a seismic cross-section illustrating the problems with data described above is shown in Figure 5.

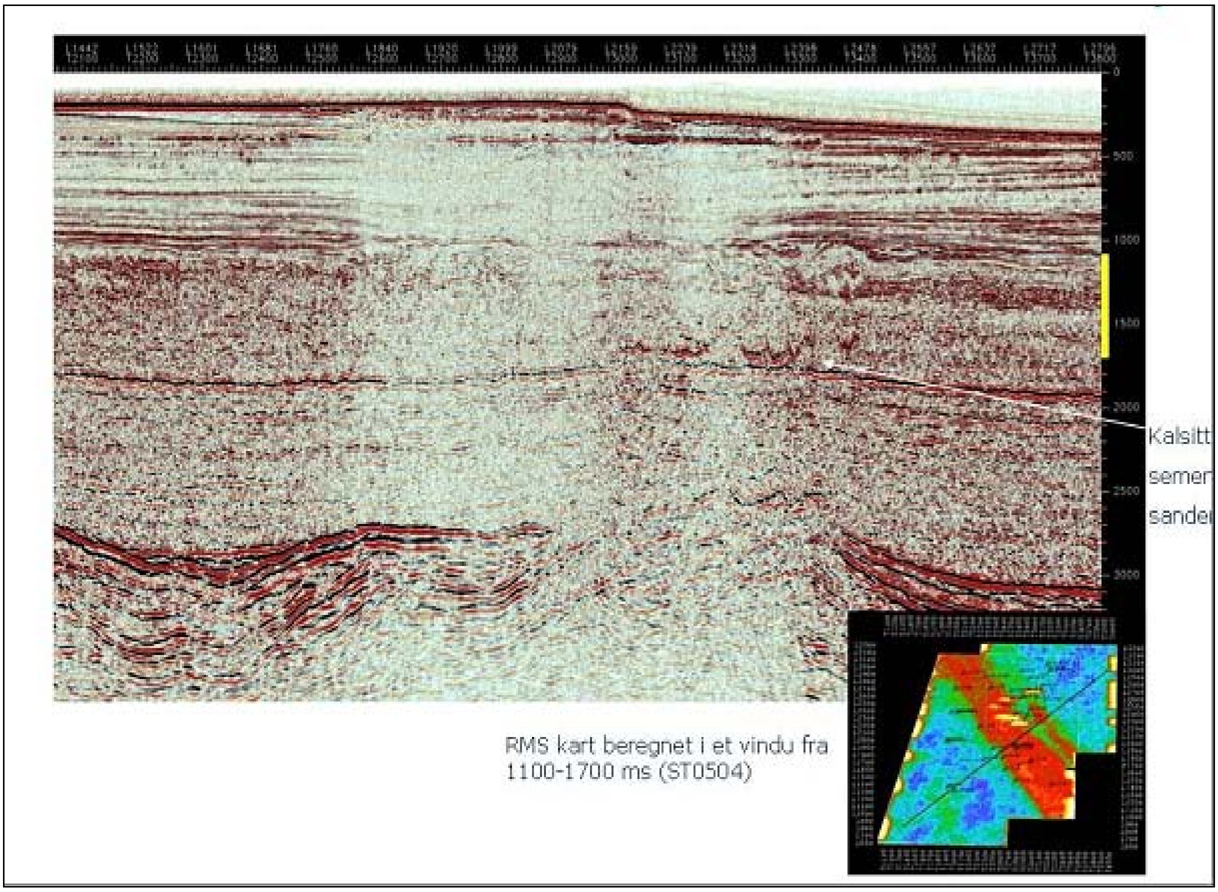


Figure 5: Seismic data quality, Gullfaks HF.

3 Part A

3.1 The wells in Gullfaks Sør

The Gullfaks Sør field is located in the Statfjord formation, and consists of three zones. These are Nansen, Eiriksson and Raude. The reservoir model is divided into 15 layers (layer 15 inactive):

Formation	Layer
Nansen	1, 2, 3, 4, 5, 6, 7, 8
Eiriksson	9, 10, 11, 12, 13
Raude	14, 15

Well	Comments	Prod. /Inj. from 2010	Perforations in Nansen/Eiriksson/Raude	Perf. top	Perf. btm
G-2T3H	Prod. start 1999	-	N, E, R	3706	4930
G-2ML	Prod.start 2004	P			
F-4AT3H	Prod.start 1999	P			
G-3T2H	Prod.start 2001	-	N	4457	4955
G-1H	Prod.start 2003	-	N, E, R	4526	5253
F-2ML	Prod.start 2004	P			
F-1H	Future well (but included in basecase)	P			
E-3H	Future injection well (but included in basecase), shut in 5 y before end simulation	I			
G-4H	Future well (but included in basecase)	P			
E-2BH	Future injection well (but included in basecase), shut in 5 y	I			

	before end simulation				
G-3Y3HT4	Prod. start 2005 Lost?	-			
E-1Y3H	Start 2006 Gas injector	-	N, E, R		

Table 1: Old Wells.

Well	Total perforated length [m]	k_h/k_v	High permeable layers
W1	997,6802	10	4, (7), 9, (10), 12, 13
W2W3	1095,714	10	4, (7), 9, (10), 12, 13
W4W5	1249,737	10	4, (7), (9), (10), 12, 13
W6W7	963,3361	10	((3)), 4, (10), 12, 13
GI-2	238,48	10	((3)), ¤, 7, (8), 9, (10), 12, 13
GI-4	231,3422	10	((1)), (3), 4, 7, ((8)), 9, (10), 12, 13

Table 2: New wells.

The data is found in the 'Statfjord_(landsby_2010)' directory in the Gullfaks database. We can see that layer 4 is the most permeable layer in the formation. Other high permeable layers are 9, 12 and 13. The parenthesis in Table 2 indicates the degree of high permeability.

There is assumed zero skin in the model. The wells are completed with 6 5/8" screens, 8.5" wellbore. In the base-case, five wells are producing from 2010 and two wells are injecting, see Table 1. In addition, 6 more wells are added in the extended case, four producers and two injectors. The well trajectories are shown in Figure 6.

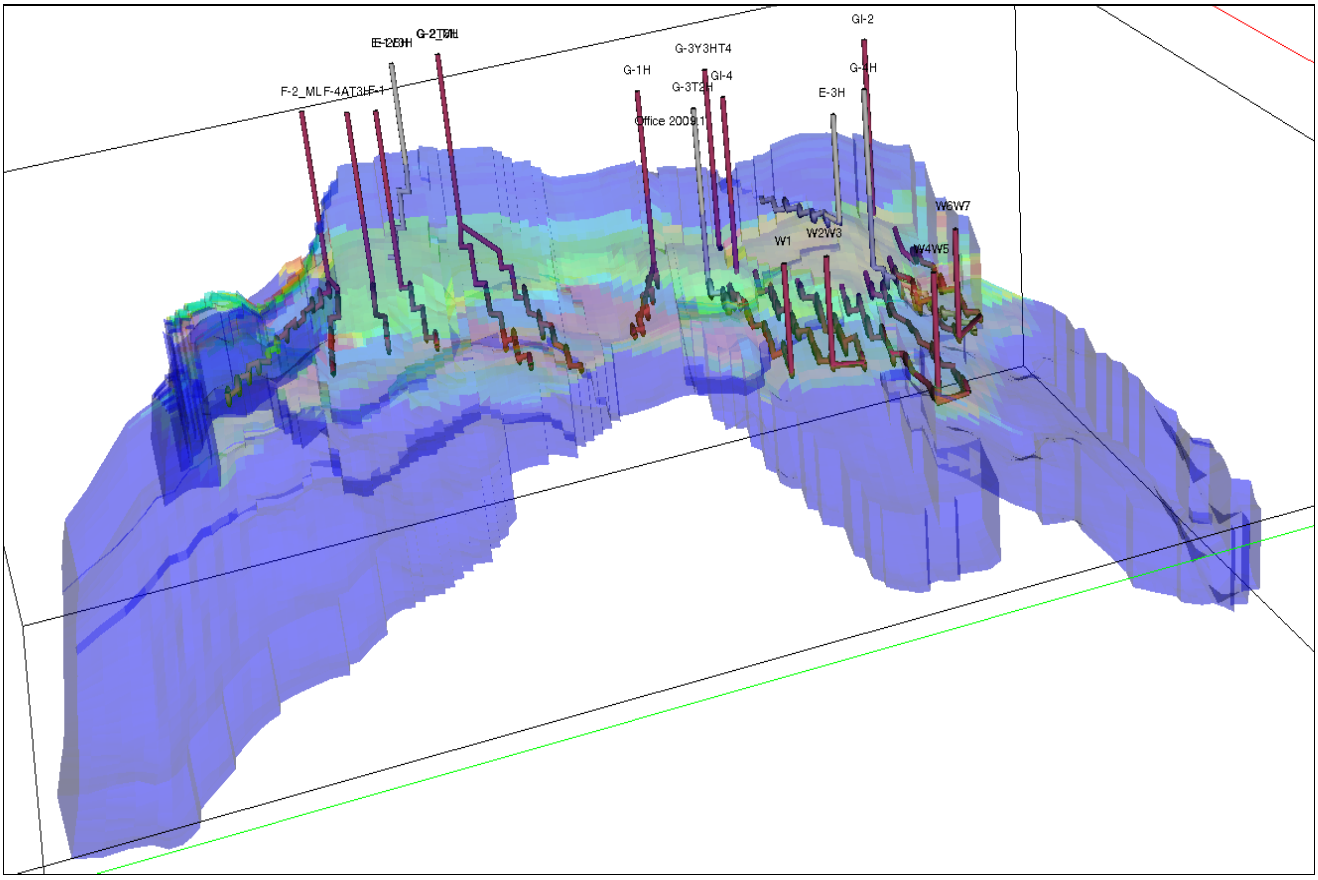


Figure 6: The reservoir with well trajectories, extended case.

Permeability in the different layers in the Gullfaks Sør model:

At "GRAF" we can see the different permeabilities in the 14 different layers, by choosing horizontal section for each layer. The results from the figures match with the observations from the wells. Examples shown from typical layers, high permeability layer 4, low permeability layer 6, mixed/medium permeability layer 3:

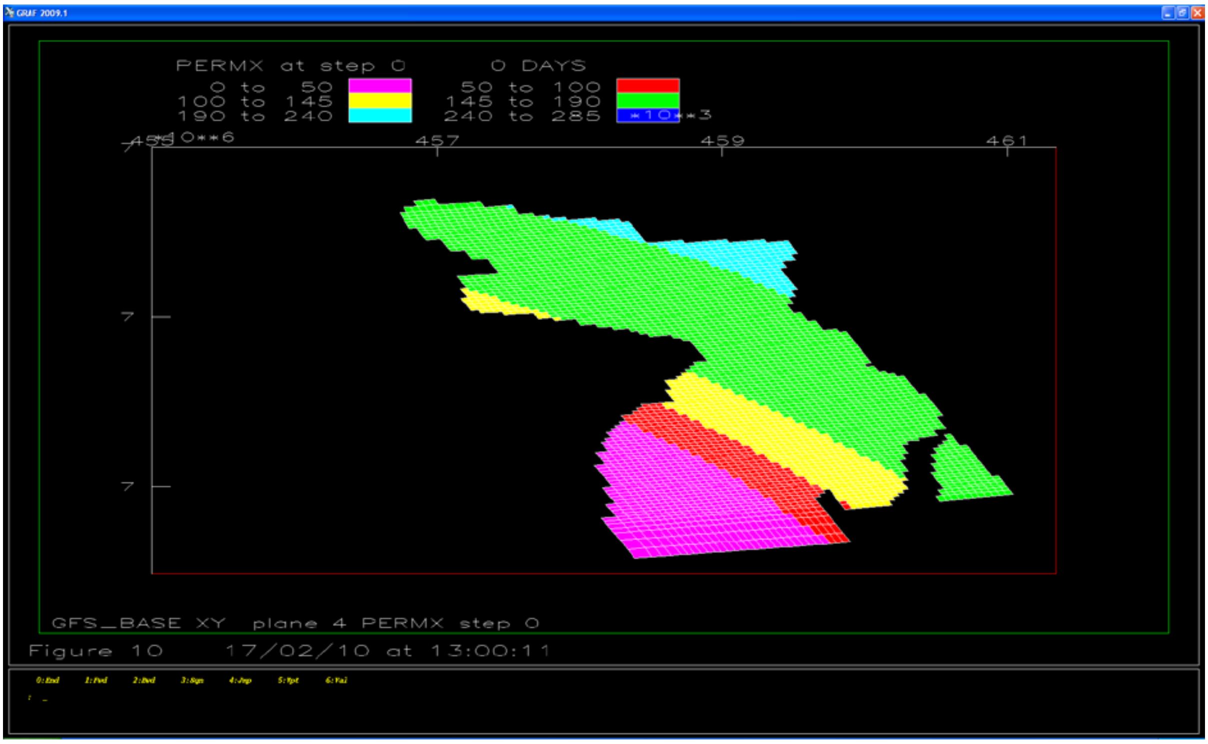


Figure 7: Layer 4.

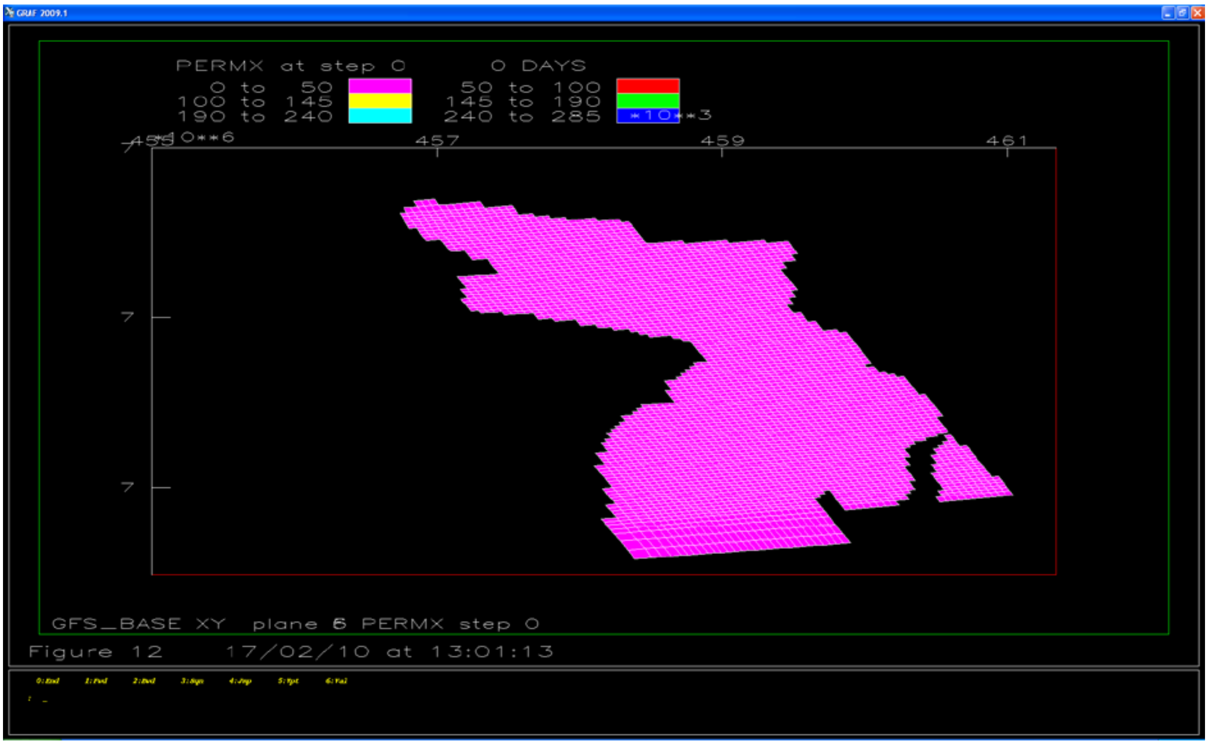


Figure 8: Layer 6.

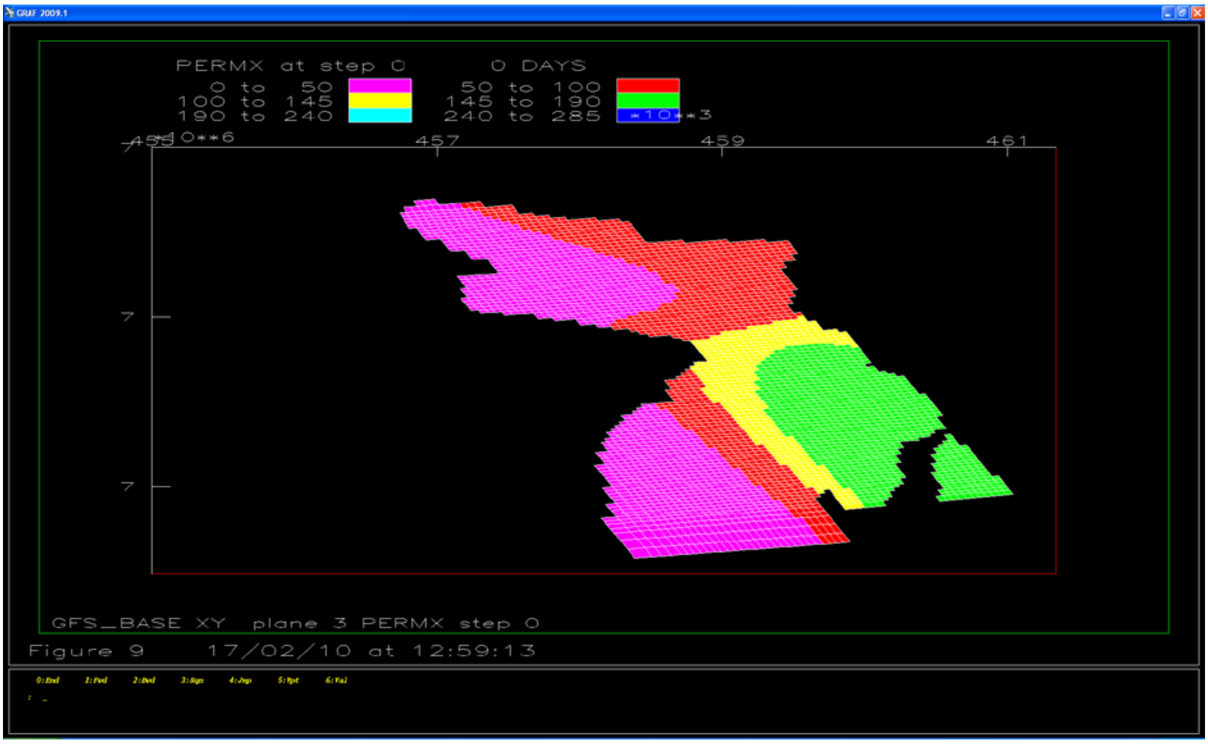


Figure 9: Layer 3.

3.2 Simulation Results

3.2.1 Reference Case

Field

The reference case consists of 9 producers and 3 injectors. The total field production rates of oil and gas, and the water cut are displayed in Figure 10.

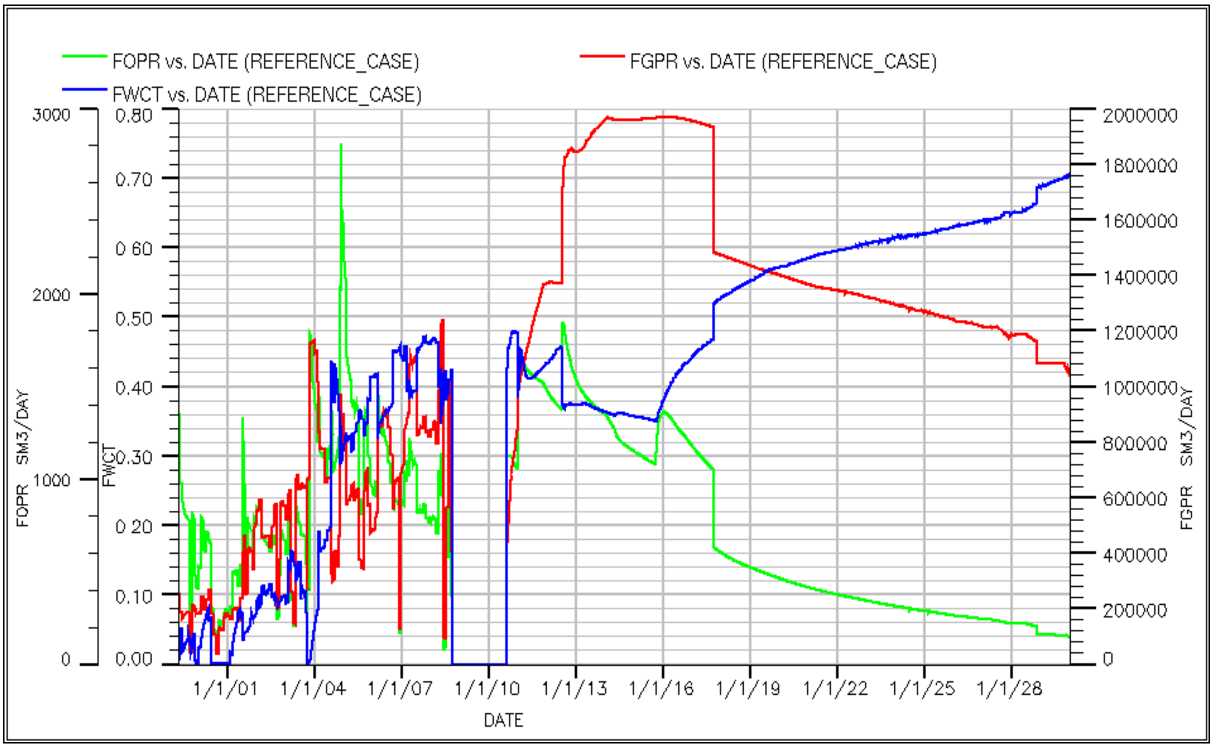


Figure 10: Field Oil Production Rate, Field Gas Production Rate and Field Water Cut.

3.2.2 Extended Case

Field

The extended case will, in addition to the wells and injectors from the reference case, also include 2 Gas Injectors on the existing E-template and 3 branched and 1 single oil producers on a new template. New total field production rates of oil and gas, and the water cut are displayed in Figure 11.

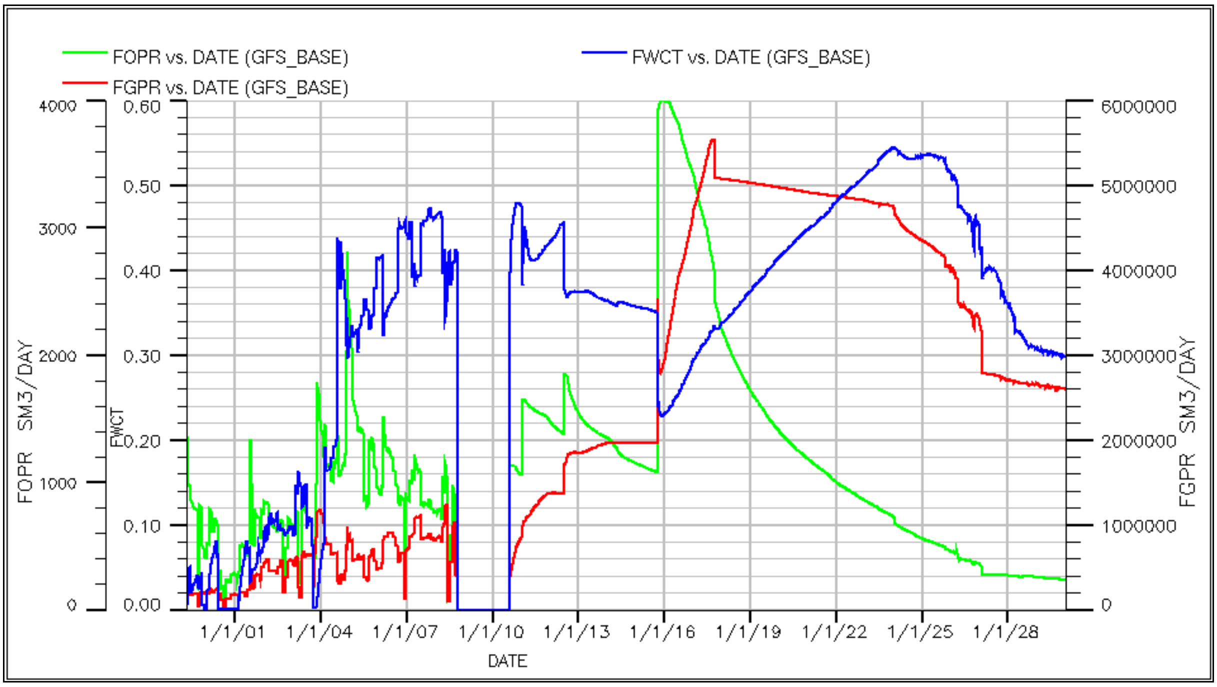


Figure 11: Field Oil Production Rate, Field Gas Production Rate and Field Water Cut.

Wells

The new single oil producing well is called W1 and the three branched oil producers are called W2W3, W4W5 and W6W7 respectively. The well oil production rates of the new wells are displayed in Figure 12. As seen W1 has a production rate plateau at 500 Sm^3/day, while W2W3, W4W5 and W6W7 have production rate plateaus at 800 Sm^3/day. But the plateau production rates lasts only for approximately 1 to 2 years, and the production rates start to fall. W4W5 is shut down 1/1/2027.

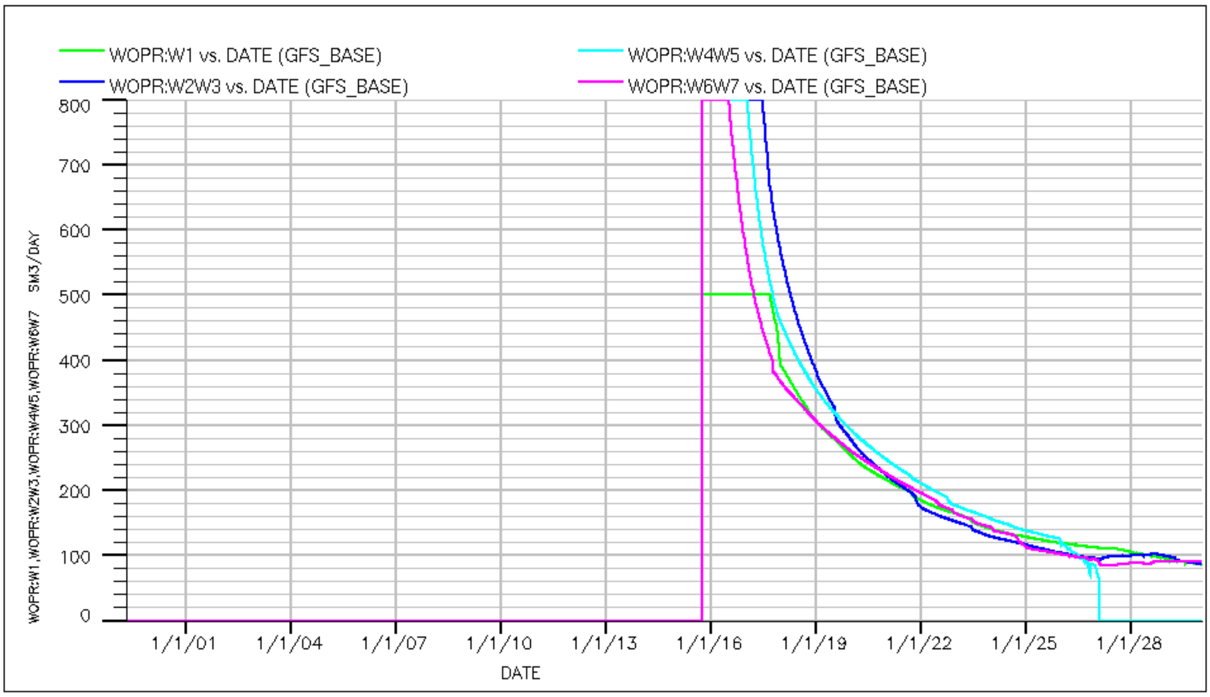


Figure 12: Well Oil Production Rates W1, W2W3, W4W5 and W6W7.

The well gas production rates of the new wells are displayed in Figure 13. The gas production rates rise up to production rate plateaus of 1 000 000 Sm^3 over a period of approx. 1 to 2 years. The gas production rate of W4W5 starts to fall about 1/1/2026 and is shut down 1/1/2027.

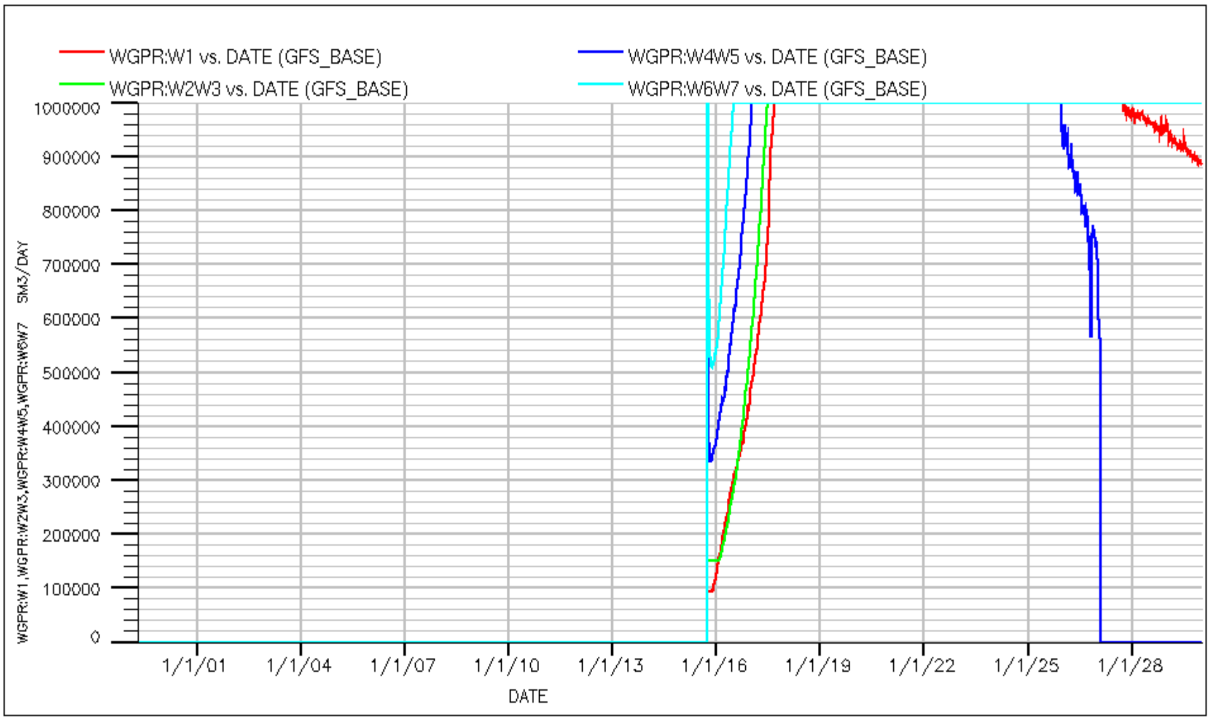


Figure 13: Well Gas Production Rates W1, W2W3, W4W5 and W6W7.

The well gas-oil ratios for the new wells are displayed in Figure 14.

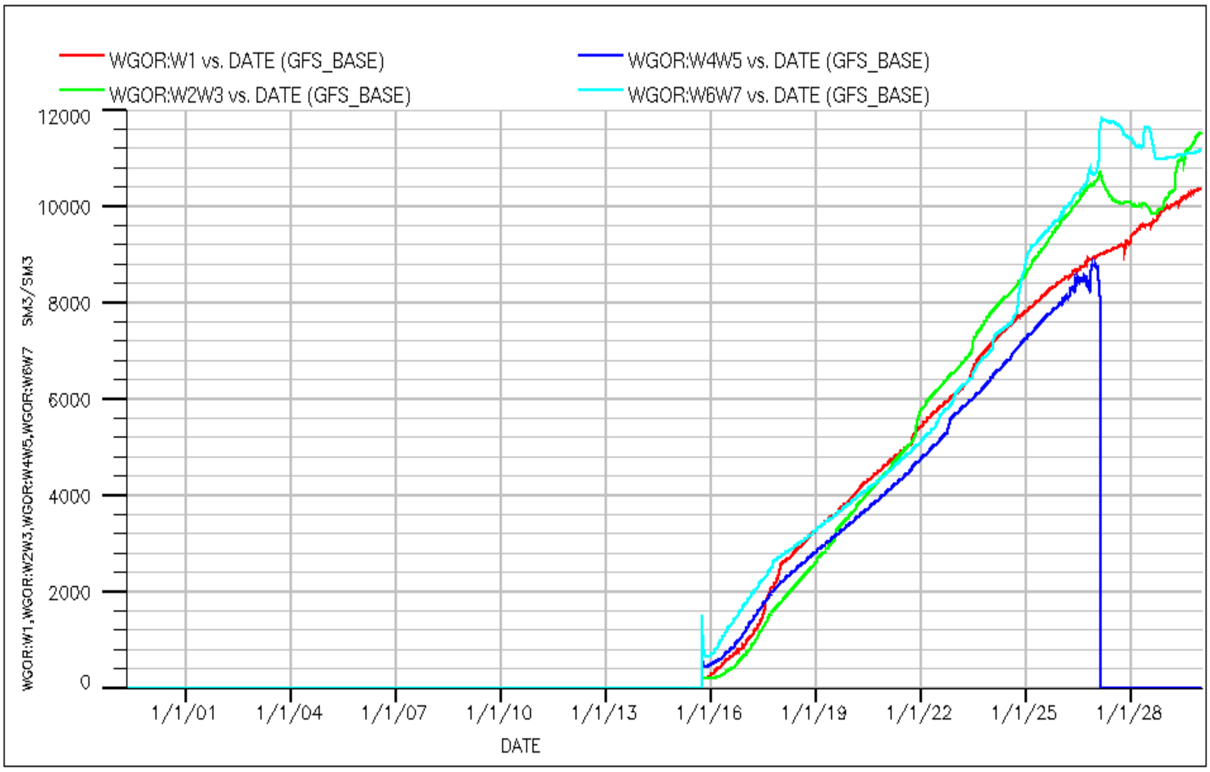


Figure 14: Well Gas Oil Ratio W1, W2W3, W4W5 and W6W7.

The well water cuts for the new wells are displayed in Figure 15. The variations in water cut in the wells are considerable, as well W4W5 produce over 60% water at its maximum in 2026, while well W6W7 produce approx. 5% water at the same time, and has its maximum at 12% at the start of production. W1 and W2W3 both have their maximum water cut at approx. 40% in the beginning of 2028.

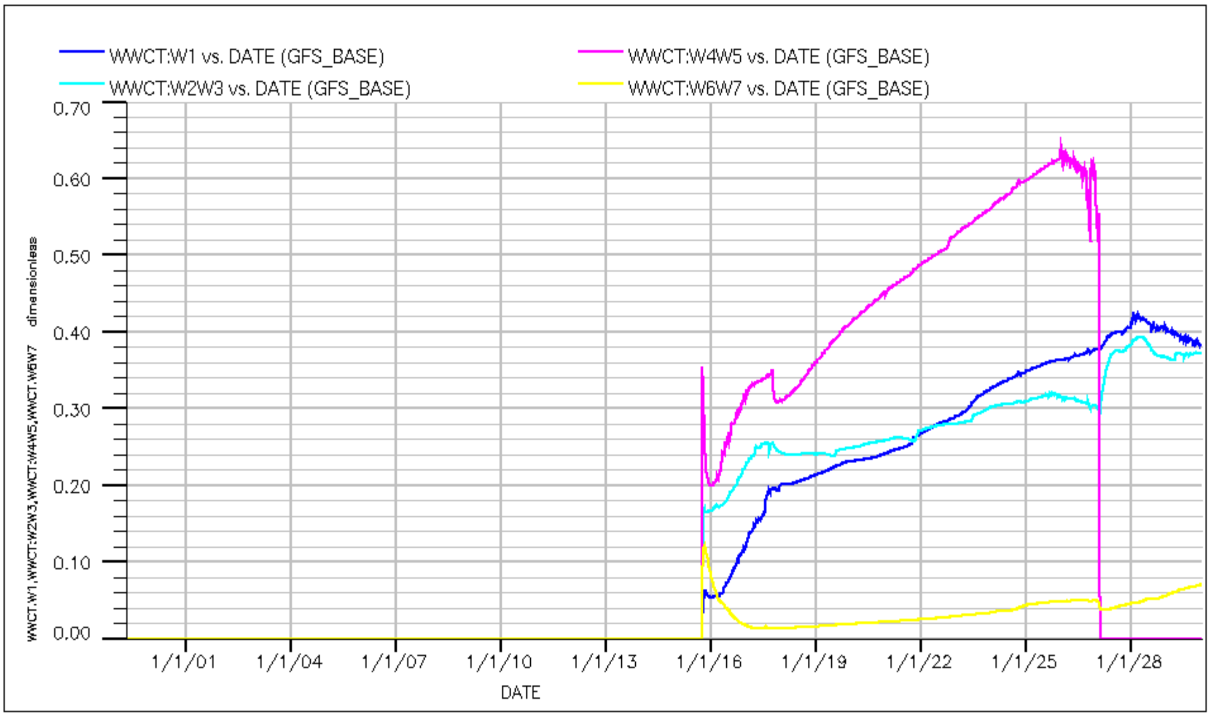


Figure 15: Well Water Cut W1,W2W3, W4W5 and W6W7.

The bottom hole pressures of the wells start at approx. 400 bara at the start of production, and falls steadily to approx. 100 bara at the end of production. This is displayed in Figure 16: Well Bottom Hole Pressure W1, W2W3, W4W5 and W6W7

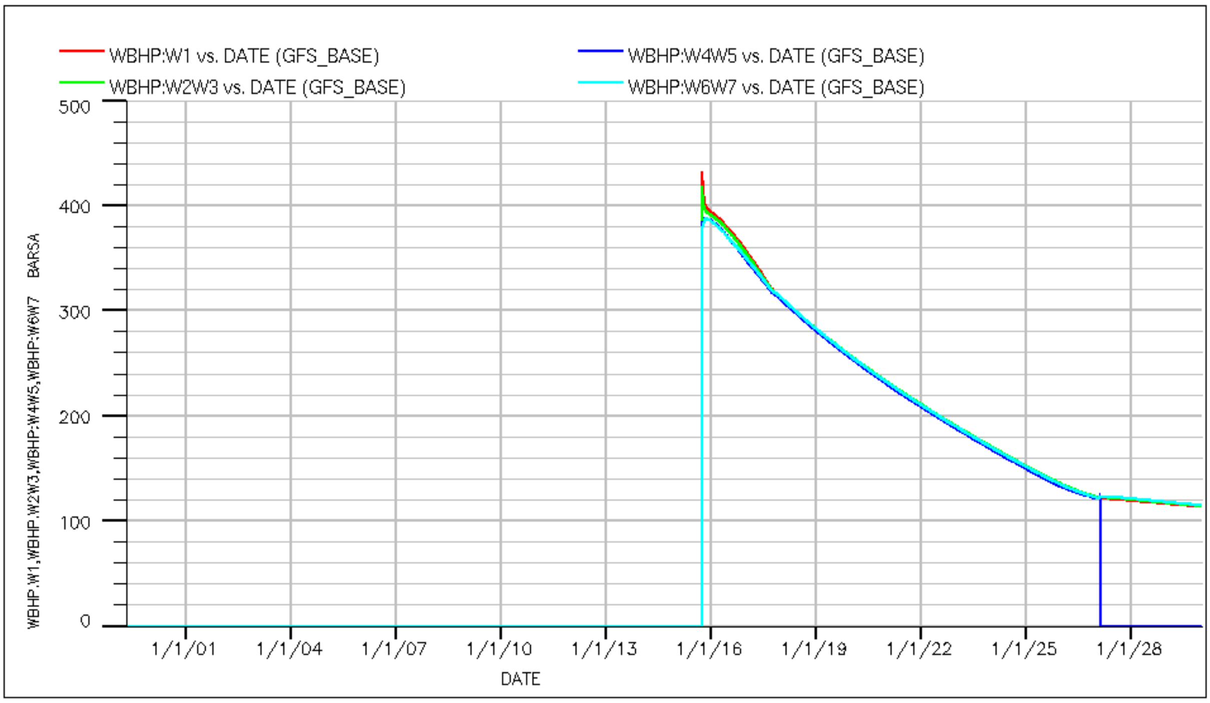


Figure 16: Well Bottom Hole Pressure W1, W2W3, W4W5 and W6W7.

W1:

Oil production rate plateau of 500 Sm^3/day from start of production to late 2017, where the production rate starts to fall. At the same time the gas production rate plateaus at 1 000 000 Sm^3/day. The gas production rate plateau lasts to late 2027, when the production rate starts to fall. At this time the oil production rate and water cut also has a visible fall. The water cut rise from approx. 6% at the start of production to approx. 20% in late 2017, and continues to rise at a lower rate to approx. 42% in early 2028 and then drops (Figure 17).

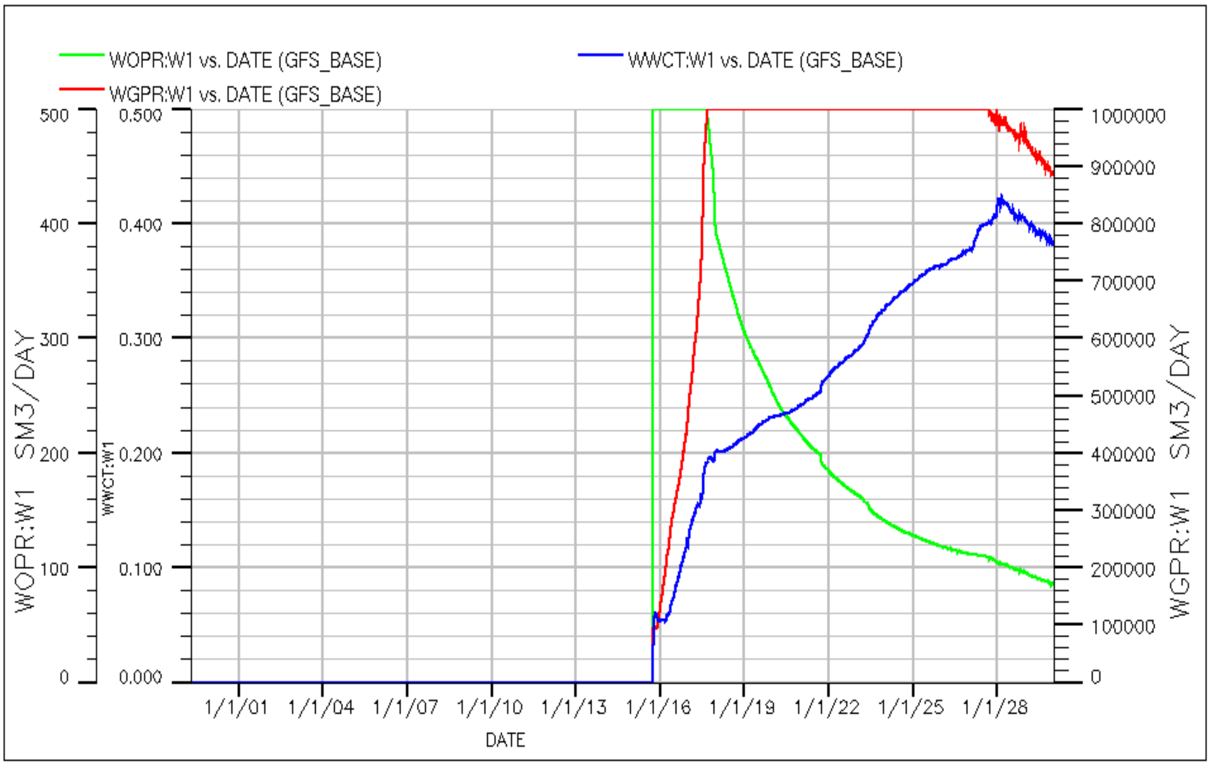


Figure 17: Well Oil Production Rate, Well Gas Production Rate and Well Water Cut for well W1.

W2W3:

Oil production rate plateau of 800 Sm^3/day from start of production to midway in 2017, where the production rate starts to fall. At the same time the gas production rate plateaus at 1 000 000 Sm^3/day. The water cut rise from approx. 14% at the start of production to approx. 25% midway in 2017, and continues to rise at a lower rate to nearly 40% in the beginning of 2028 (Figure 18).

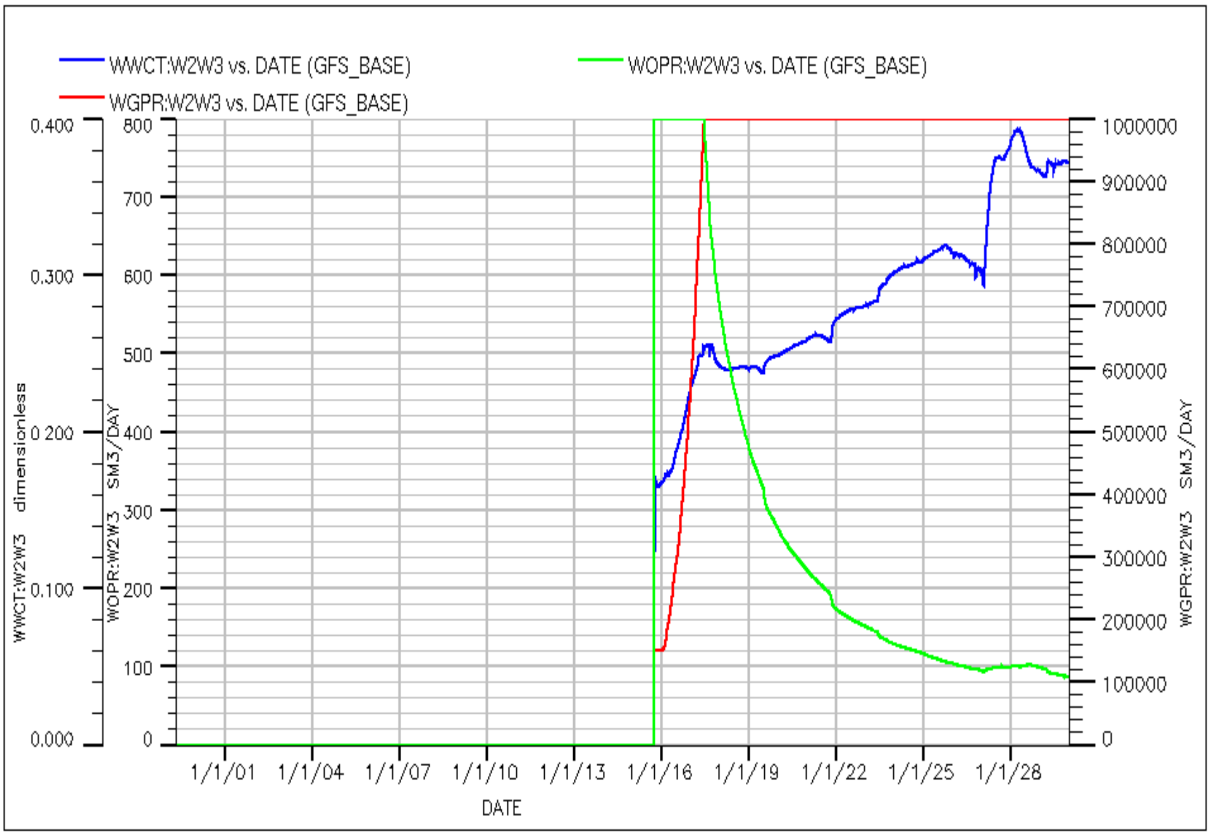


Figure 18: Well Oil Production Rate, Well Gas Production Rate and Well Water Cut for well W2W3.

W4W5:

Oil production rate plateau of 800 Sm^3/day from start of production to the beginning of 2017, where the production rate starts to fall. At the same time the gas production rate plateaus at 1 000 000 Sm^3/day. The gas production rate plateau lasts to late 2025, when the production rate starts to fall. At this time the oil production rate and water cut also has a visible fall. The water cut rise from approx. 20% at the start of production to approx. 35% in early 2017, and continues to rise at a lower rate to approx. 64% in late 2025. The well is shut down 1/1/2027 (Figure 19).

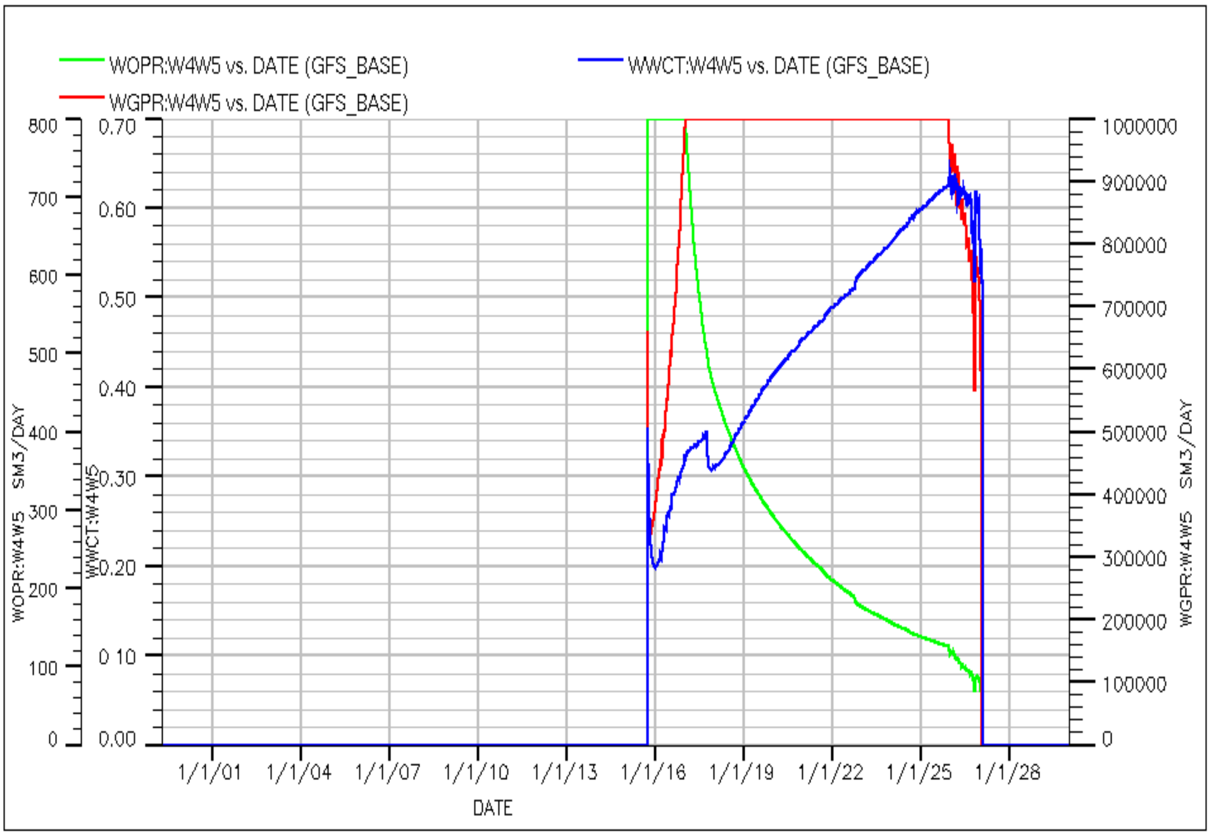


Figure 19: Well Oil Production Rate, Well Gas Production Rate and Well Water Cut for well W4W5.

W6W7:

Oil production rate plateau of 800 Sm^3/day from start of production to late 2016, where the production rate starts to fall. At the same time the gas production rate plateaus at 1 000 000 Sm^3/day. The oil production rate hits a second plateau in early 2027 at approx. 90 Sm3/day, and lasts until end of production. The water cut falls from approx. 12% at the start of production to approx. 1.5% in late 2016. From here it starts to rise to approx. 5% in early 2027, where it suddenly drops to approx. 4%, and starts to rise until it reaches a water cut of approx. 7% at the end of production (Figure 20).

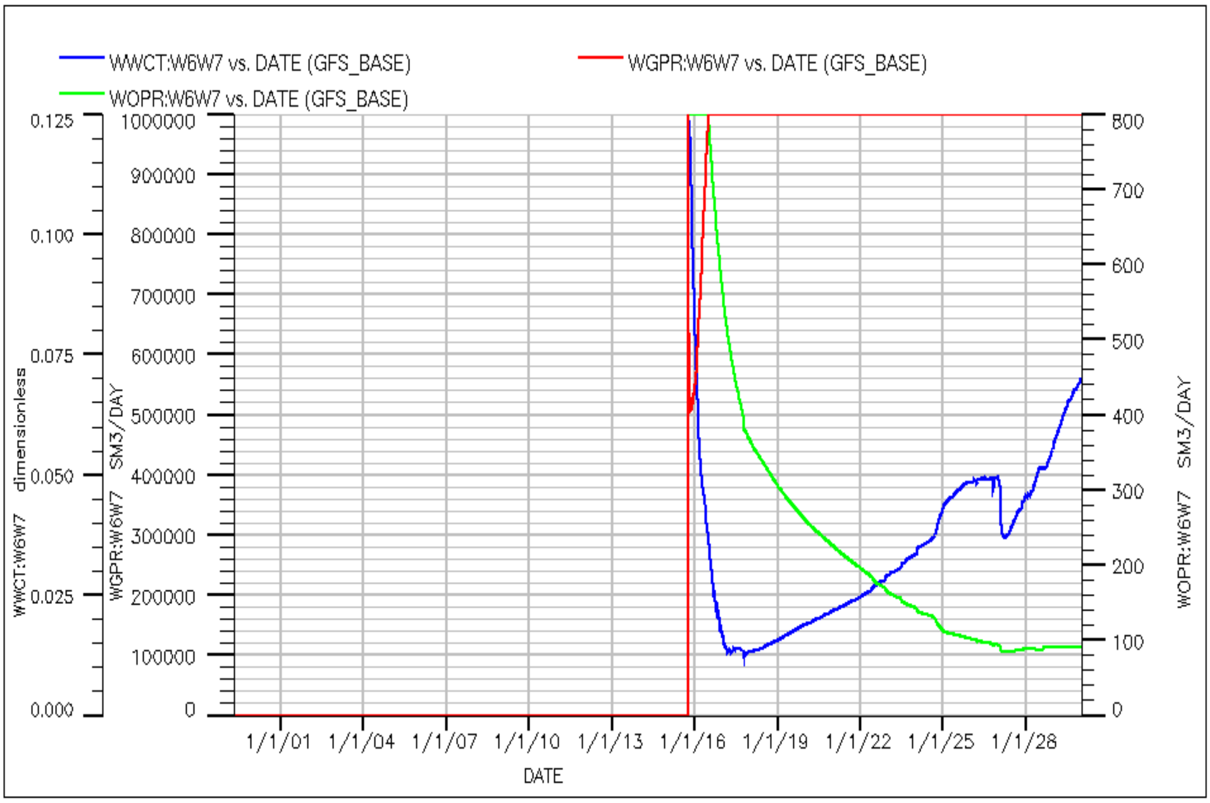


Figure 20: Well Oil Production Rate, Well Gas Production Rate and Well Water Cut for well W6W7.

3.2.3 Comparison

<u>Field</u>

The field oil production rate of the reference case and the extended case is displayed in Figure 21. When the new wells start producing there is a sudden rise of the field production rate from approx. 1 200 Sm^3/day to approx. 4 000 Sm^3/day in the extended case. But after a short period of time it starts to fall rapidly until late 2017, where the fall decreases. This increase in field production rate will increase the total field production of oil as displayed in Figure 22. The field oil efficiency (the recovery factor) is displayed in Figure 22.

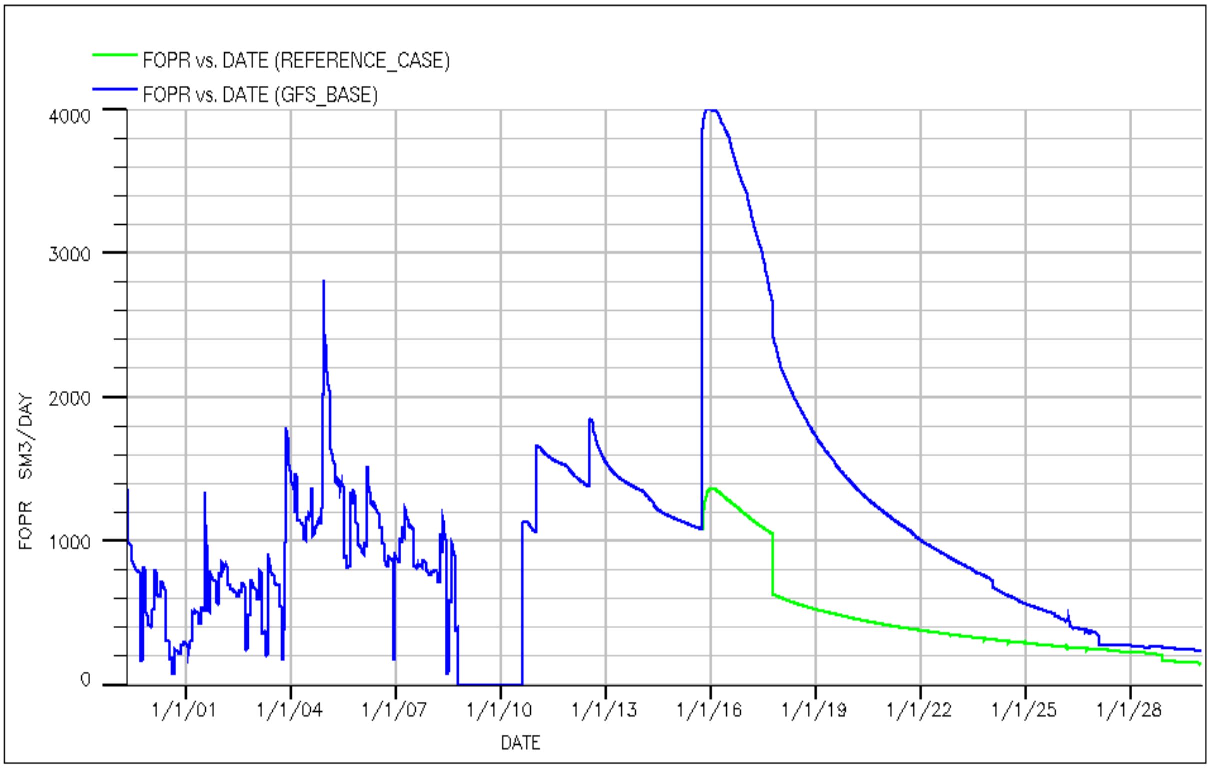


Figure 21: Field Oil Production Rate for the Reference Case and the Extended Case.

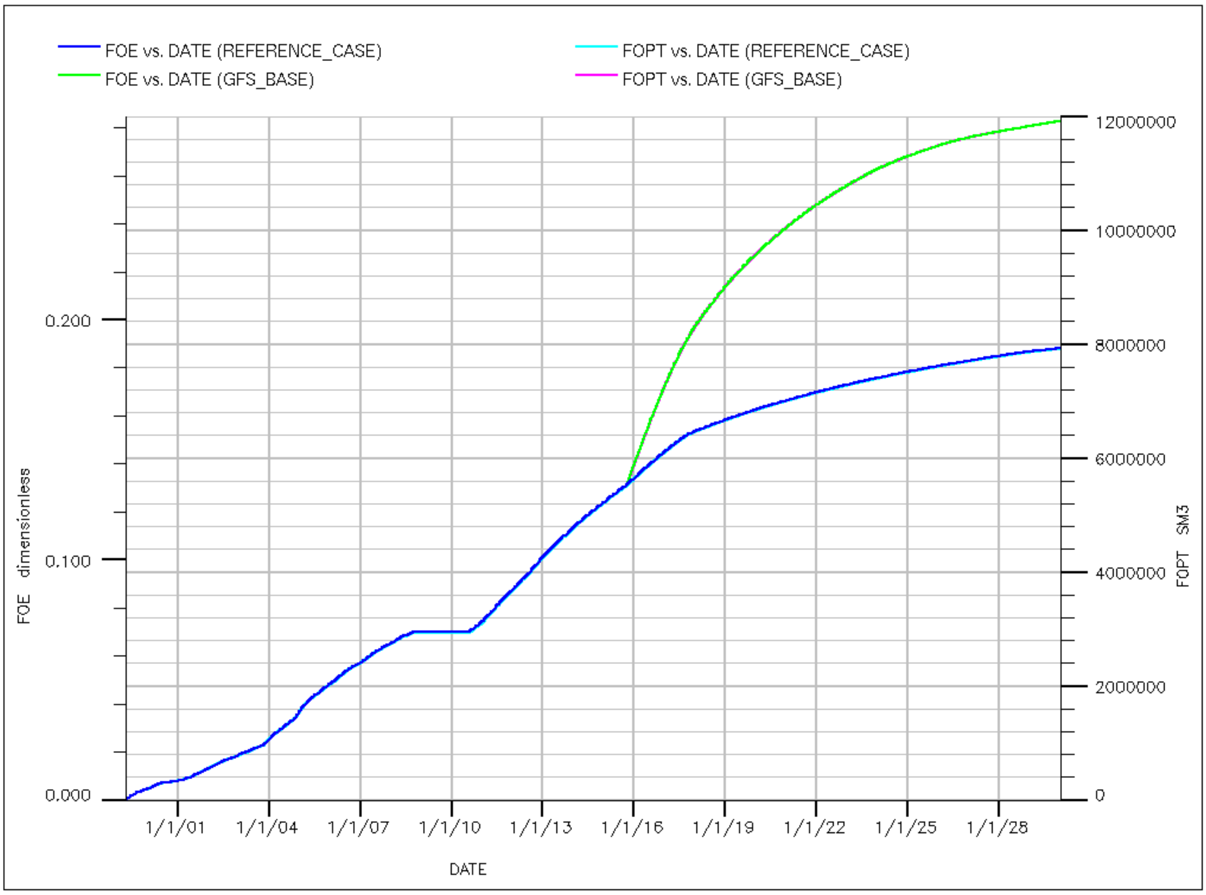


Figure 22: Field Oil Production Total for Reference Case and the Extended Case.

In 1/10/2015 in the extended case two new gas injectors are introduced to the field. The field gas production rates for the reference case and the extended case are displayed in Figure 23. The field gas production rate rise from approx. 2 000 000 Sm^3/day to approx. 5 000 000 Sm^3/day in about 2 years in the extended case. This increase in field production rate will increase the total field production of gas as displayed in Figure 24.

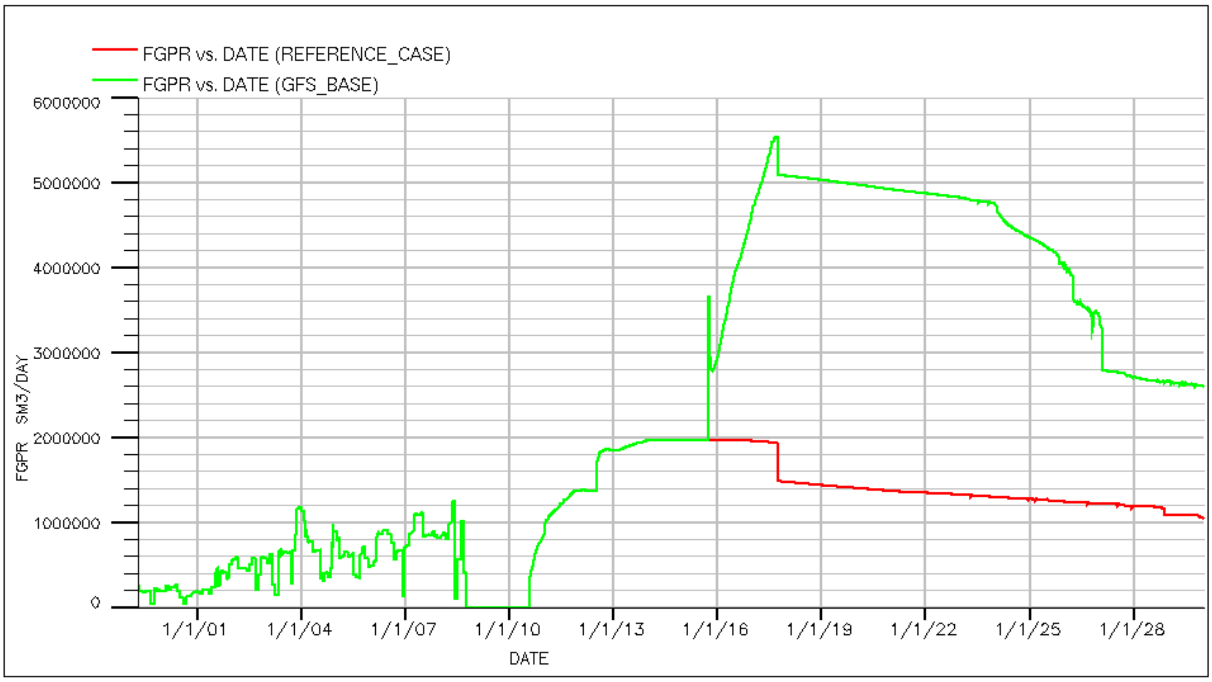


Figure 23: Field Gas Production Rate for the Reference Case and the Extended Case.

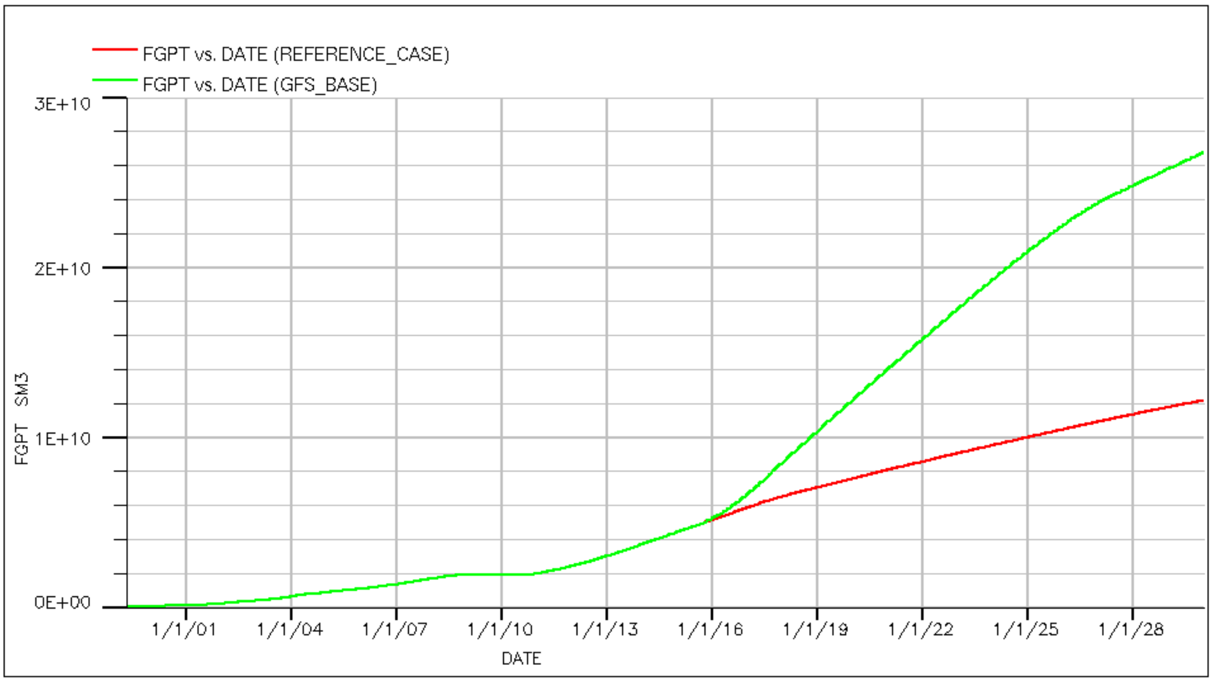


Figure 24: Field Gas Production Total for the Reference Case and the Extended Case.

The increase in field produced gas compared to oil will increase the gas-oil ratio in the extended case, compared to the reference case. This is displayed in Figure 25.

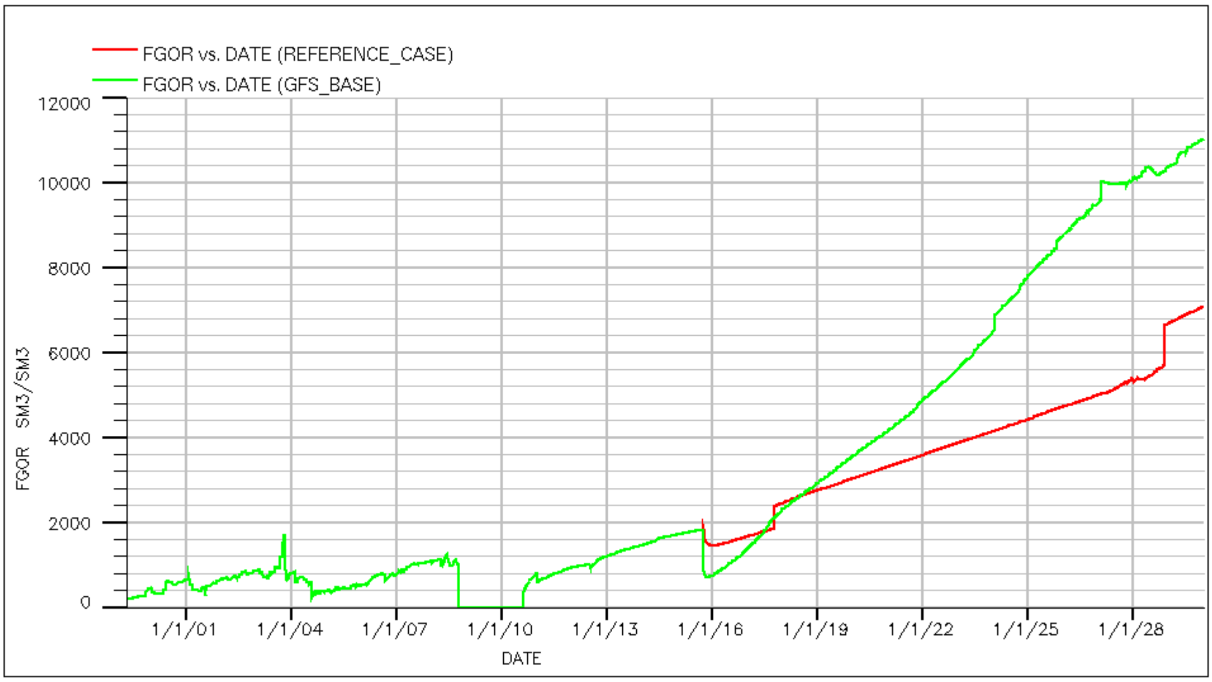


Figure 25: Field Gas-Oil Ratio for the Reference Case and the Extended Case.

Due to the increased gas production rate the field water cut decrease when the new wells start producing. This is displayed in Figure 26.

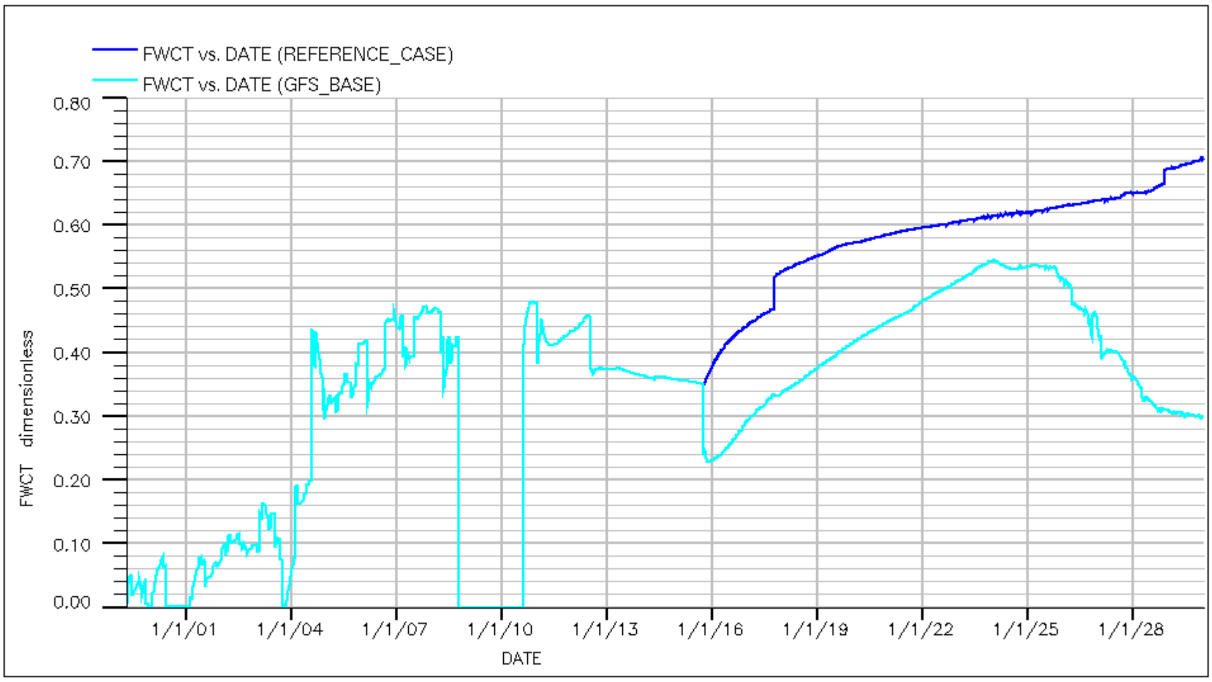


Figure 26: Field Water Cut for the Reference Case and the Extended Case.

The field pressure in the Extended Case falls at a higher rate than in the Reference Case. This is due to increased oil production. The gas injectors are supposed to keep the pressure at a higher level, but fail to do so.

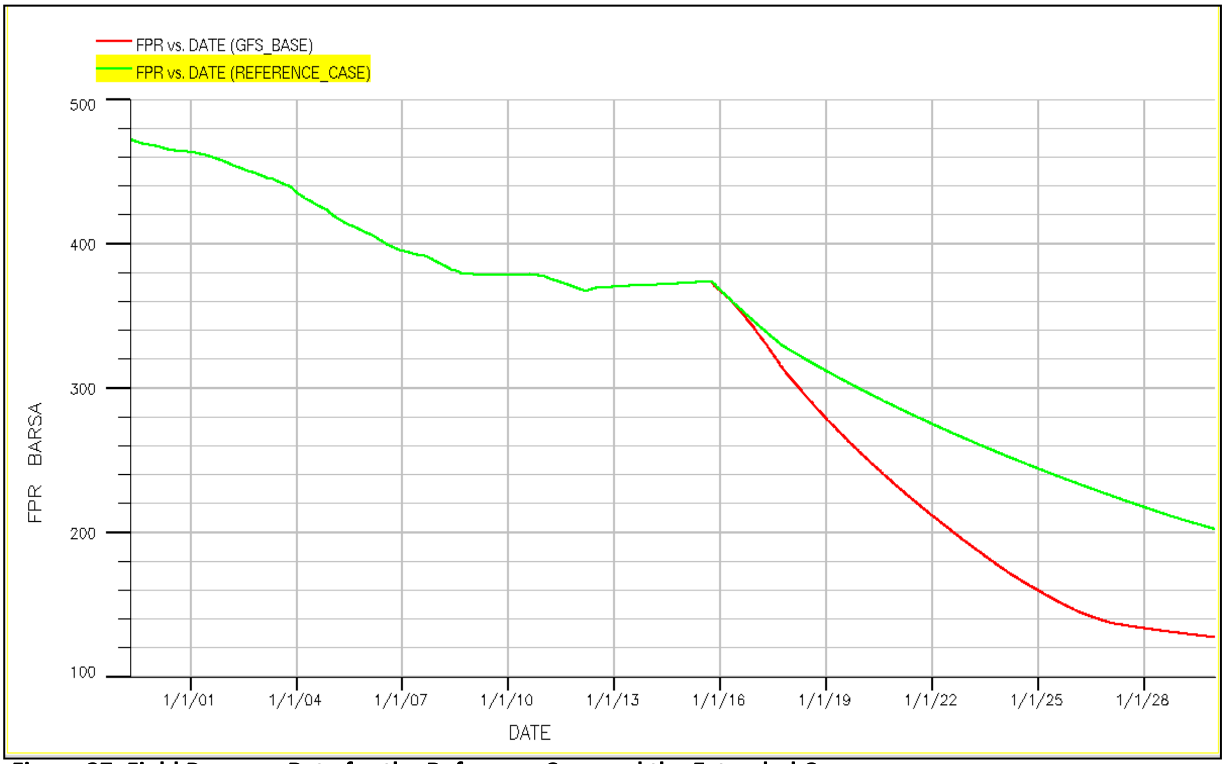


Figure 27: Field Pressure Rate for the Reference Case and the Extended Case.

Conclusion

When the field is extended with 4 producers and 2 gas injectors the recovery factor is increased from 19% to 28%, that leads to an increase in the total field production of 4 000 000 Sm^3, to a total of 12 000 000 Sm^3. But by injecting gas into the field the gas production rate rises. This increase in gas production results in a higher gas-oil ratio. When the injected gas reaches the new wells the oil production rates suddenly drops. Another observation is that the injectors do not seem to keep the pressure in the field up at a satisfying level.

3.3 Economic Evaluation

For the Economic Evaluation the Net Present Value model is used. The evaluation compares two different alternatives with each other. In the following pages the two alternatives are introduced, the assumptions are stated and the result of the analysis is shown. For the calculation of the NPV the extra produced oil and gas, compared to the reference case is used to verify the additional investment.

3.3.1 Assumption – General

The main assumptions are as followed:

- Oil price: 400 NOK/bbl increasing 3% p.a
- Gas price: 200 NOK/bbl increasing 3% p.a
- Interest Rate: 6% (Inflation 1% + Discount Factor 5%)
- Conversion factor: bbl = 6.29/1000 * Sm^3
- Drilling cost well: 150 MNOK/well
- Drilling cost branch: 50 MNOK/branch
- Drilling: max of 4 wells/year

As further assumptions it is taken that:

- all produced oil is sold
- the gas that is produced and not injected again is sold
- if more gas is injected than produced it has to be bought for the assumed gas price
- first year of production 2015
- investment is taken in 2014 and 2015

For each alternative three different cases are calculated in Table 3.

	Best Case	Normal Case	Worst Case
Oil & Gas Price	+ 5%	-	- 2%
Opex	- 30%	-	+ 30 %
Capex	- 40%	-	+ 40 %

Table 3: Best-, Normal-, Worst-case.

Assumption - Alternative 1A – Platform

The assumptions for Alternative 1A are as followed:

- Capex for Wellhead Platform: 4 000 MNOK
- Costs for Drilling: 1 050 MNOK
- Plugging and abandonment: 300 MNOK
- Opex cost: 91 NOK/bbl oe

The Investment is taken in 2013 and 2014 and the Platform is abandoned in 2030.

Assumption - Alternative 2A – Subsea Solution

The assumptions for Alternative 2A are as followed:

- Capex for two subsea templates: 2 500 MNOK
- Costs for Drilling: 1 050 MNOK
- Plugging and abandonment: 200 MNOK
- Opex cost: 111 NOK/bbl oe

The Investment is taken in 2013 and 2014 and the templates are abandoned in 2030.

3.3.2 Economic Results A

In the following part the economic results are shown. For that the NPV per year, the cumulative NPV and a sensitivity analyses is used.

Alternative 1 – Platform

The yearly NPV (Figure 28) shows the high investment at the beginning in 2013 and 2014. After this two investment years the yearly production is beneficial in all three cases until the year 2024. After that point gas has to be sold for injection and those additional cost make this alternative uneconomic in those specific years.

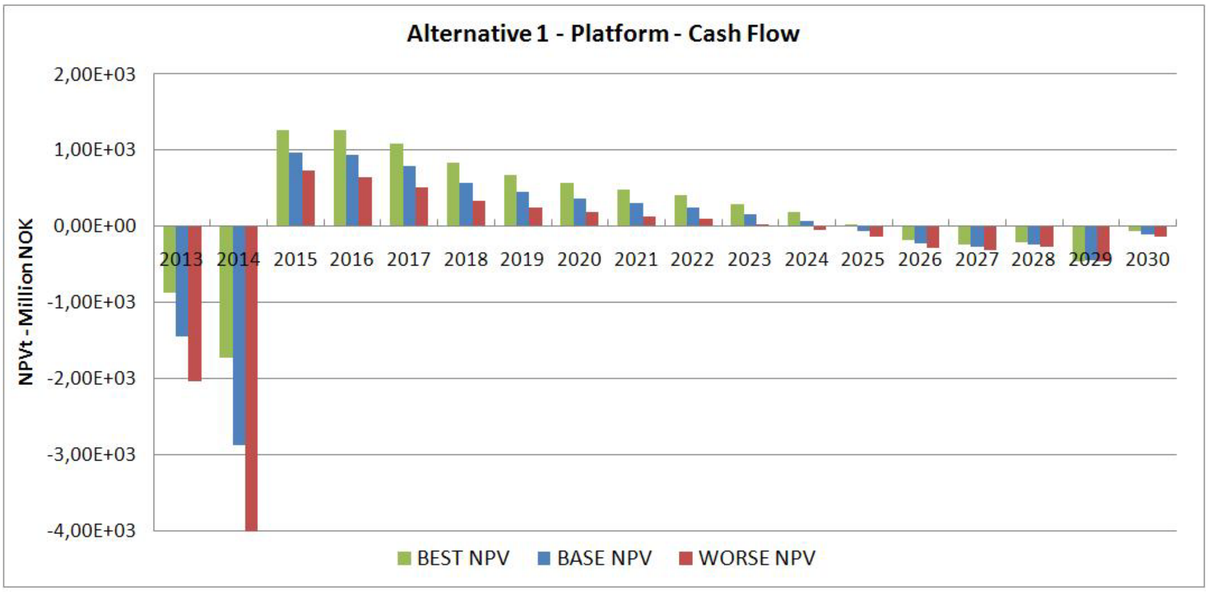


Figure 28: Alternative 1-Part A-yearly NPV.

Even with the profitable yearly production until 2024 the cumulative NPV (Figure 29) shows that it is only rentable in the best and the normal case, as the best case reaches the break even point (BEP) in 2016 and the Base case after additional 5 years. In the worst case the yearly cash flow isn't enough to reach the break even point, so the cumulative result stays below 0.

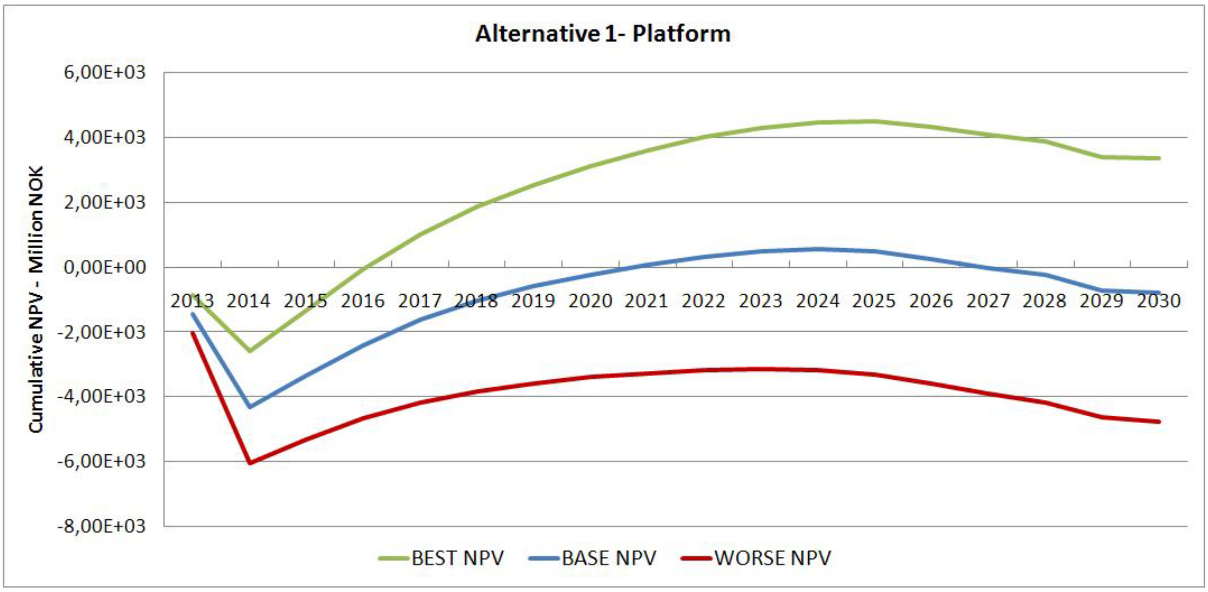


Figure 29: Alternative 1 - Part A - Cumulative NPV.

The highest influence factors for the economic result (Figure 30) is the oil price as a small change of 5 % got the impact of increasing the NPV with 50 %. A decrease with 40 % of the Capex cost would lead to an increased NPV with 220%, whereas a reduction of the gas opex by 30 % got the effect of increasing the NPV with 180 %, which highlights the strong sensitivity to the opex costs.

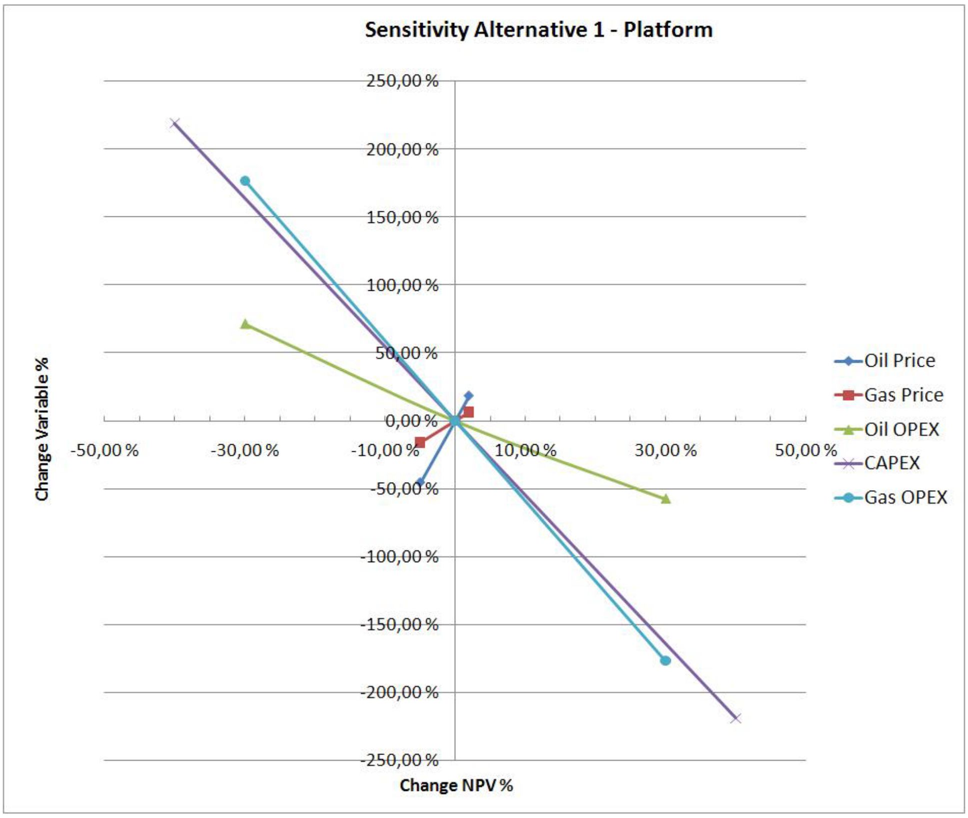


Figure 30: Alternative 1- Part A – Sensitivity.

Alternative 2- Subsea

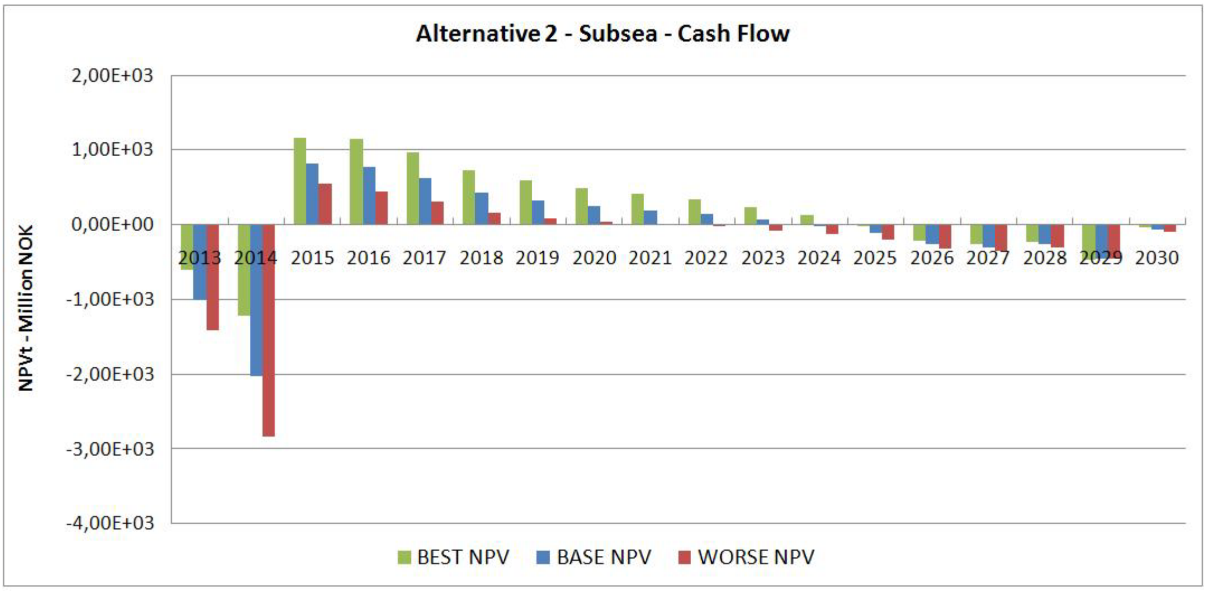


Figure 31: Alternative 2 - Part A - yearly NPV.

Figure 31 shows a yearly positive cash flow in the years 2015 until 2021 for all three cases. In the best case this period is three years longer. After 2025 the production is not beneficial, as it shows a negative NPV. However the positive NPV period leads to a positive cumulative NPV in the Best and Base Case (Figure 32). Were the BEP is reached after 4 and 7 years.

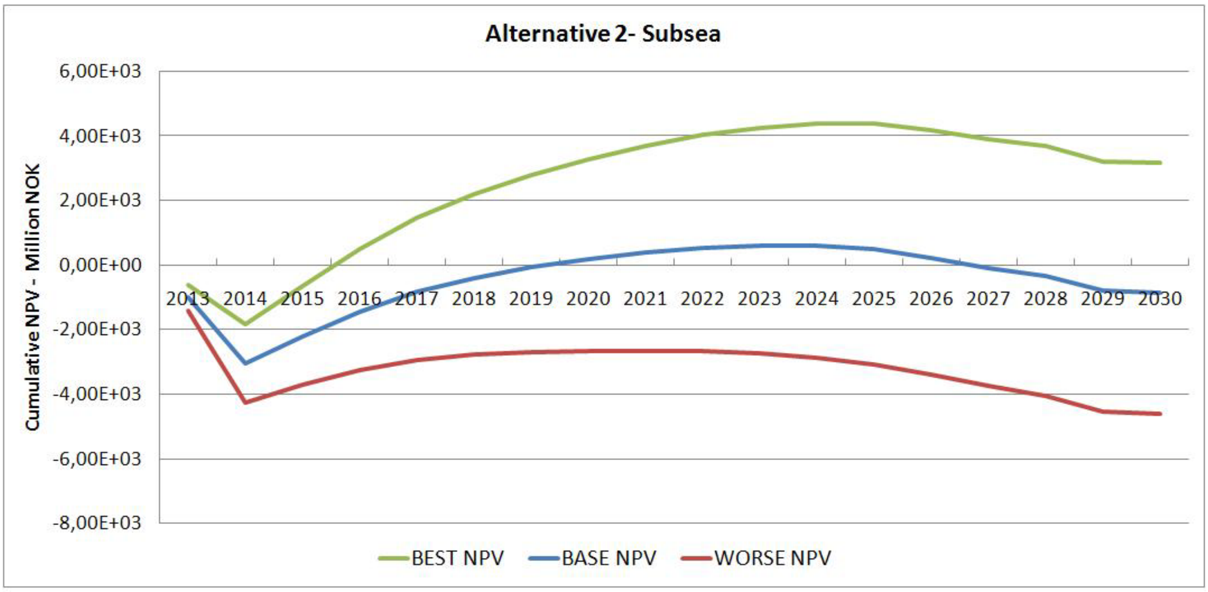


Figure 32: Alternative 2 - Part A - Cumulative NPV.

The economic result in Alternative 2A is heavily dependent onto the gas opex costs (Figure 33). Decreasing or Increasing those cost with 30 % leads to a change in the NPV of nearly 200 %. Only the oil price got a higher impact, were a change of 5 % is followed by an increase with 42 %.

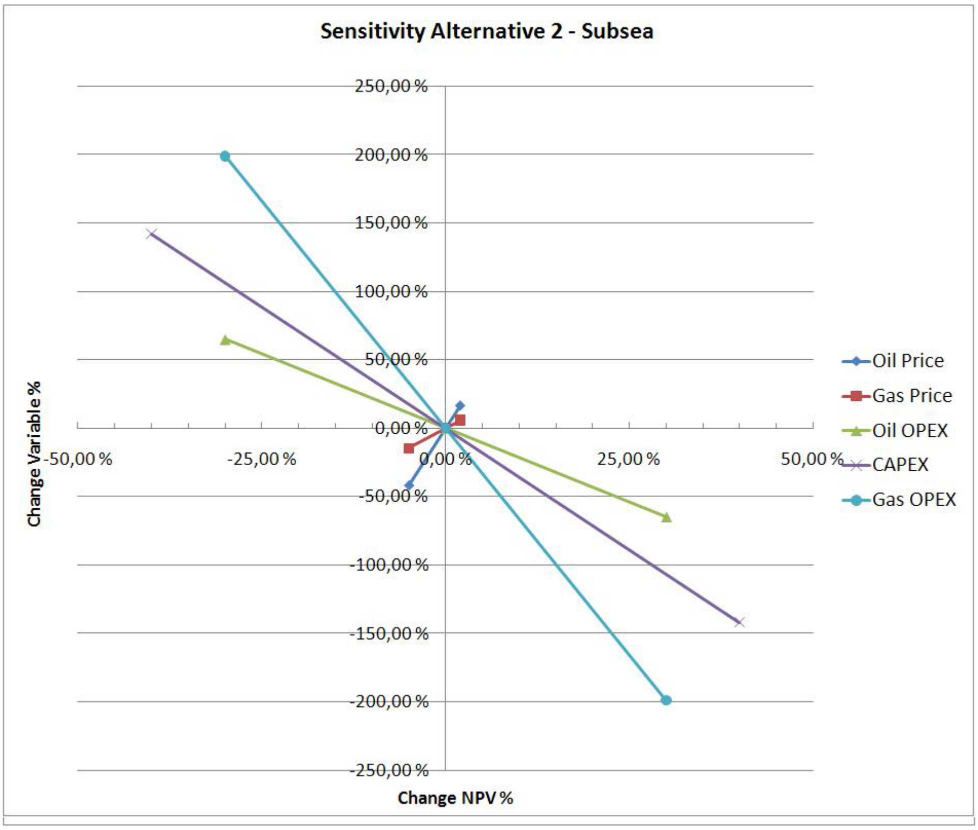


Figure 33: Alternative 2 - Part A – Sensitivity.

The lowest influence is caused by the oil opex and gas price.

Comparison and recommendation Part A

	Alternative 1			Alternative 2		
	Best	Base	Worse	Best	Base	Worse
Total NPV in MNOK	3349,19	-806,69	-4777,13	3169	-874,60	-4621,51
Highest NPV in MNOK (year)	4510 (2025)	544 (2024)	-3150 (2023)	4390 (2024)	600 (2023)	-2650 (2021)
BEP	2016	2021	-	2016	2019	-

Table 4: Comparison of alternatives 1-2 Part A.

The decision between Alternative 1 and 2 is a question about risk. As Table 4 highlights the highest and lowest NPV is reached with Alternative 1A (Best-, Worst-Case) and the breakeven point is reached 2 years later (base case) then in Alternative 2A (base case). So while taking the risk of the higher investment the revenue could be higher at the end. However a close look must be taken at the yearly cash flow, as the comparison between the total and highest NPV and Figure 28 and Figure 31 shows the production is nott profitable until 2030. This is related to the fact that more gas is injected than produced and this gas has to be bought.

4 Part B

Smart wells have been used in Gullfaks Sør Statfjord, but with mixed experiences. The purpose of Challenge 3 in Gullfaks Village 2010 was to implement a multilateral well and/or Inflow Control Devices in the field. Multilateral technology is a cost effective solution to increase the drainage area in a reservoir and to be able to access otherwise left out reserves. A five branch well was supposed to be used in an attempt to improve the oil recovery.

Eclipse was used to implement the well in a reservoir model, and simulations were run to see the effects. The results and an economic analysis are shown in this report. There is also a short introduction to smart wells and some positive and negative comments about smart wells and ICD.

4.1 Smart Wells

Smart wells, also called intelligent wells, are wells that are equipped with sensors/monitoring equipment and completion components that can be remotely adjusted to optimize production, and that includes a surface system to collect and transmit the production data to a remote facility for analysis. They are designed to obtain real-time downhole data to gain critical wellbore and reservoir information like pressure, temperature, flow rate, pH, water cut and gas fraction.

Smart well completions enable multiple reservoirs to be accessed with a single well while avoiding the common problem of cross-flow caused by different reservoir pressures. Smart wells enables the development of marginal fields by allowing flows to (in the case if injection), and from, multiple reservoirs to be controlled remotely and contained within a single well.

Smart wells have sensors and valves that can be controlled independently, and can therefore be employed in projects involving different objectives, such as production control of gas and water, production by different zones in stratified reservoirs, and margin fields. They can also operate valves to control production, which can be used for instance to maximize net present value (NPV), to mitigate risk, to improve oil production, or to control water production. Their ability to manage reservoirs remotely also reduces potential well intervention costs.

Smart wells can, as mentioned, be used to restrict or exclude production water and gas from different zones in a production well. They can be used to control the distribution of water or gas injection in a well between layers, between compartments, or between reservoirs. As a result, the operator can manage where water is injected or oil is extracted to mobilize unswept reserves.

The subsystems that comprise a "smart" well include a telemetry system for conveying data to and from the surface, downhole sensors for collecting the desired parameters in the well, controls to reconfigure the downhole tools, and a surface subsystem. The surface subsystem includes a data collection terminal software to analyze the data and make decisions based on the output, and some means of transmitting this data to a remote facility, if required. These systems are shown in Figure 34

The key components of a typical intelligent completion are:

1. Flow control devices, which are usually hydraulically-operated internal control valves used to control flows into and out of the reservoir
2. Feed-through isolation packers that enable hydraulic control lines to be fed through to subsurface control valves, and which isolates the individual zones along the wellpath.
3. Downhole sensors, which report pressure, temperature and flowrates back to the surface
4. Control systems, comprising hydraulic and/or electrical surface systems, used to monitor and control subsurface conditions.

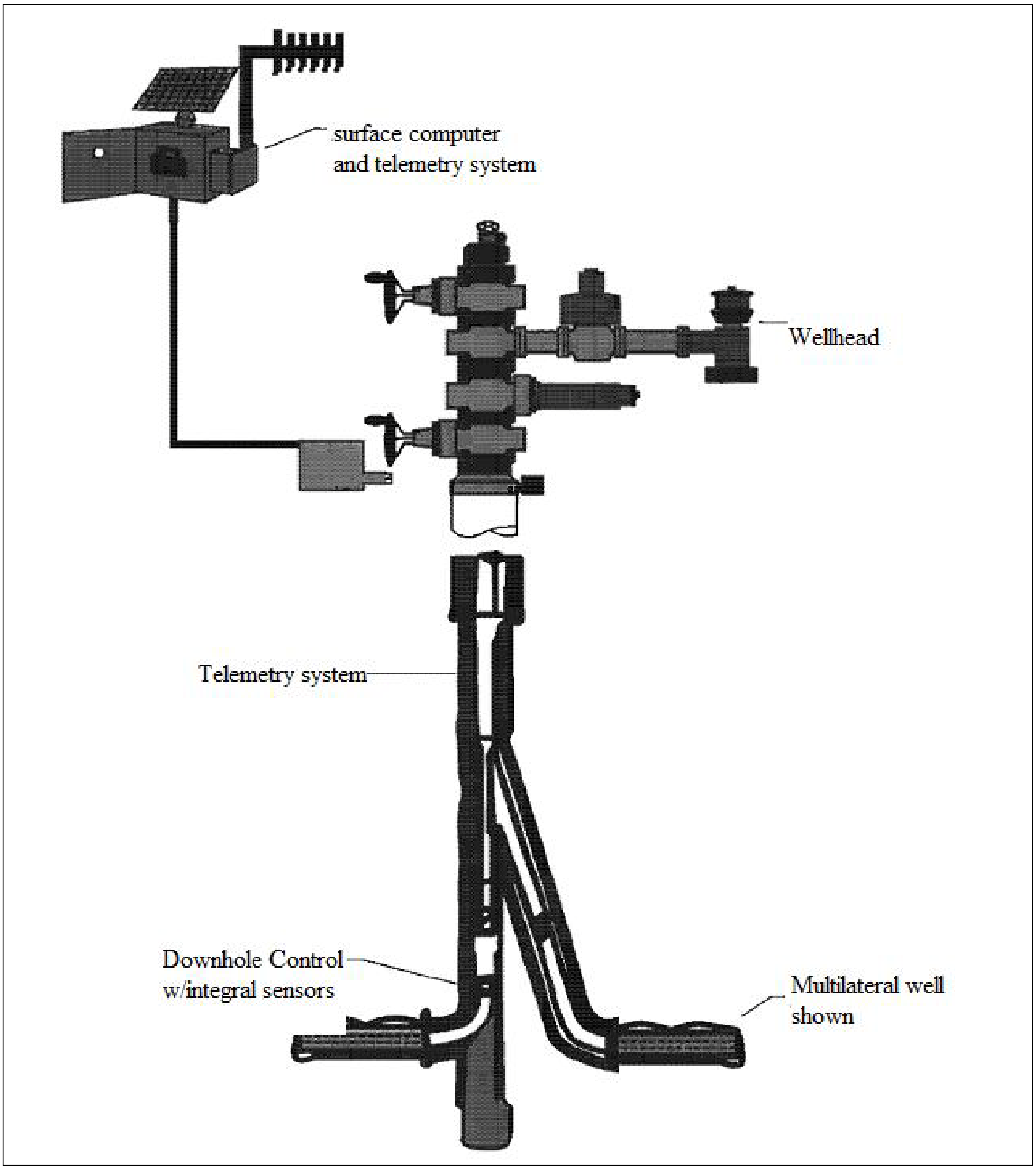


Figure 34: Smart Well System.

Currently there are three different types of Intelligent Well Systems in the industry: all-electric, electro-hydraulic and all-hydraulic systems. Over 95% of the wells installed worldwide have been all-hydraulic systems. Reasons for the preference for all-hydraulic systems include lower cost, less complexity, perceived higher reliability, and faster delivery times, but the tradeoff is functionality. Some of the functionality that operators must sacrifice when selecting all-hydraulic systems over the more advanced electro-hydraulic and all-electric systems are: bidirectional movement, infinite number of positions and position feedback of the flow-control valves, as well as fewer control lines required to operate them.

4.1.1 All-Electric Systems

The all-electric systems use a single ¼-in. TEC (tubing encased conductor) to operate multiple control valves and multiple permanent monitoring systems. The valves are operated by an electric motor/actuator derived from the aerospace industry, which provides an infinite number of positions with accurate positioning feedback. These systems are also the most expensive and usually, due to the electronic components used down-hole, the temperature ratings are lower than with the hydraulic systems.

4.1.2 Electro-Hydraulic Systems

The electro-hydraulic systems require a hydraulic bus and an electric bus to operate multiple valves. The hydraulic bus provides the power to actuate the valves, while the electric bus provides the means of selecting which valves to operate. These systems use down-hole electronic components and solenoid valves for their operation and can also include integrated monitoring systems.

4.1.3 All-Hydraulic Systems

In hydraulic systems the flow control components are completely independent from the permanent monitoring components. The flow-control devices can be either on/off or multiposition valves and they can have either balanced-piston- or spring-return-type actuators. On the balanced-piston design, two control lines are used for the operation of each valve, with each control line ported to either side of the piston ("open" and "close" ports). Applying hydraulic fluid pressure on one control line while the other is vented moves the valve in one direction; to move the valve in the opposite direction the operation is inverted. The valve is operated with only one control line. Applying pressure to the single control line moves the valve in one direction and when this pressure is bled off a spring is used to move the valve in the opposite direction (this spring can be either a mechanical spring or a pneumatic spring). There are two ways of controlling multiposition valves. Using a mechanical transmission provides a hard stop that limits the travel of the valve's insert with each pressure cycle, thus limiting the flow area through the ports, so alternate pressure cycles between the "open" and "close" ports move the valve through its multiple positions. Alternately, a hydraulic dispenser can limit the amount of hydraulic fluid injected into the actuator, thus limiting the stroke of the valve, while multiple pressure cycles on the "open" port move the valve incrementally through its multiple positions.

Although the reduced number of control lines required to operate the spring-return actuator may seem to be a good enough reason to select it over a balanced piston actuator, it is the latter that has been accepted as the preferred choice among operators.

4.2 Multilateral wells

Multilateral wells are defined as wells with two or more laterals drilled from a common wellbore. These laterals may be horizontal, vertical, or deviated, and in the same or in different levels. Different types of multilateral wells are shown in Figure 35.

The application of multilateral technology is driven mainly by complex reservoir and geologic settings for which laterals may be used to produce bypassed or separated pockets of hydrocarbons in depleted, faulted or layered and heavy oil reservoirs. Because only a single vertical wellbore is required, multilateral well designs require less drilling time. Often have fewer equipment and material requirements, and increase hydrocarbon production. The advantages of such wells can be summarized as improving the drainage geometry, reducing coning and improving sweep efficiency.

There are some factors that must be considered in planning for implement of the multilateral wells. The strategy for selecting the multilateral well position is to identify where it is possible to have multiple horizontal wells to reduce the number of wells needed for economic recovery. The other criteria for selecting the potential candidates for multilateral drilling include:

(1) Small amount of oil, isolated blocks, and bypassed oil.

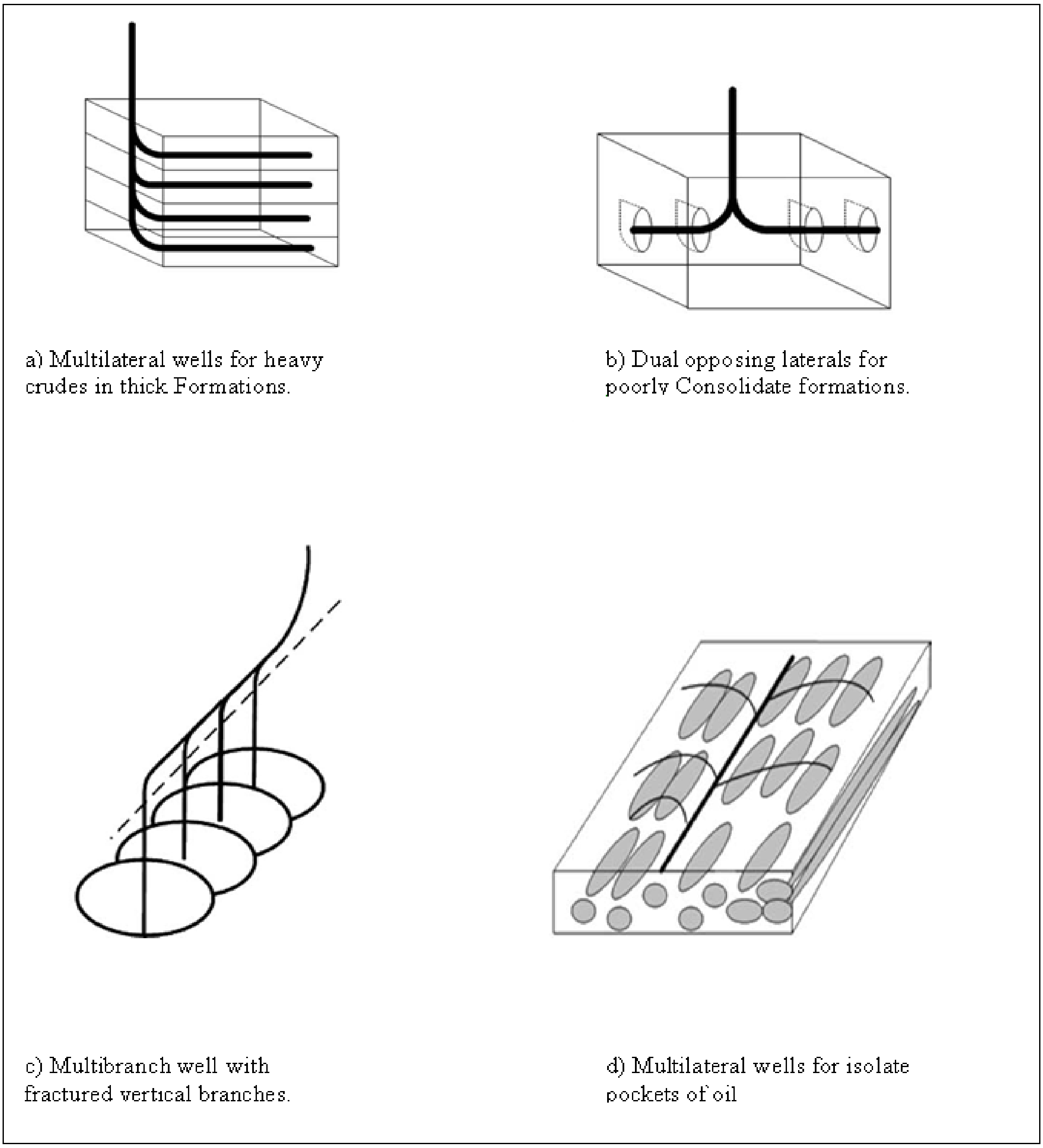
(2) Individual zones or structures separated by permeability barriers.

(3) The horizontal well is not perpendicular to maximum permeability.

(4) Increased production is required.

(5) The wellbore pressure drop is large compared to the reservoir drawdown pressure.

So it is clear that selecting suitable placement of multilateral wells is much important and can provide higher recovery for relatively low increment cost. However, the reservoir characteristics such as permeability, thickness values, heterogeneity, existence of natural fractures, oil API gravity and the degrees of rock consolidation influence the selection of appropriate multilateral well configuration.



a) Multilateral wells for heavy crudes in thick Formations.

b) Dual opposing laterals for poorly Consolidate formations.

c) Multibranch well with fractured vertical branches.

d) Multilateral wells for isolate pockets of oil

Figure 35: Typical multilateral wells.

4.3 DIACS (Downhole Instrumentation And Control System)

DIACS is a well completion equipment and system that has the functionality to remotely control the inflow and monitor the production from several zones or lateral branches down hole individually without the need for intervention tools. The DIACS is installed as an integrated part of the completion string and consists normally of tubular components with a number of remotely controlled inflow control valves and devices, zonal isolation packers, downhole gauges for flow-, pressure- and temperature- monitoring, and downhole control lines. It is a smart well completion which permits remote operation of valves in the well controlled from the installation. The valves are controlled electronically, hydraulically or by using a combination of these. In a multilateral well it will be possible to shut down one branch while the other continues to produce if, for example, it experiences a gas surge. The use of DIACS in wells will make it cheaper to monitor the reservoir and simultaneously gather important reservoir data while the wells are producing. This is because the valves have integrated sensors that provide information on the pressure and temperature in the well and in the reservoir. These will be a tool to control and guide production. The result can be increased oil and gas production, reduced water production and a reduction in intervention costs and time. DIACS is alternatively used to remotely control and monitor the injection into several injection zones individually.

4.4 ICD - Inflow Control Device

The principle of the Inflow Control Device is to restrict flow by creating additional pressure drop, and therefore balancing or equalizing wellbore pressure drop to achieve an evenly distributed flow profile along a horizontal well. With a more evenly distributed flow profile, one can reduce water or gas coning, sand production and solve other drawdown related production problems. The ICD equalizes inflow along the length of the wellbore regardless of location and permeability variation. Balancing inflows throughout the completion string, the Inflow Control Device improves productivity, performance and efficiency, achieving an even, consistent flow of fluid along each interval. It is therefore used as part of well completion to control and optimize individual well or overall reservoir performance. It helps reduce water and gas production associated with challenges like heel-toe effects, breakthroughs of water and gas, permeability issues and wells producing high viscosity oil. ICDs are said to be passive control, and built into the actual completion string, it moderates the reservoir inflow from high productivity zones and stimulates inflows from lower productivity zones.

Figure 36: Homogenous reservoir. Left: Early water and/or gas breakthrough in the heel may occur without ICD. Right: No early water/gas breakthrough with ICD (Halliburton).

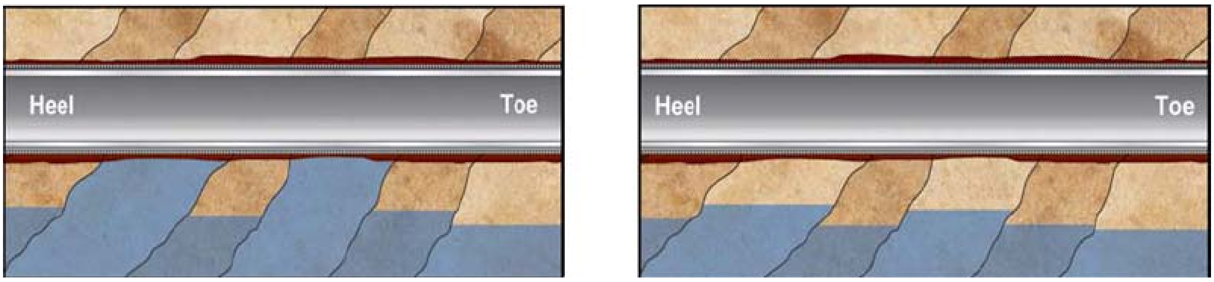


Figure 37: Heterogenous reservoir. Left: Early water/gas breakthrough without ICD. Right: No early water/gas breakthrough with ICD (Halliburton).

The tool consists of an annular chamber on a standard oilfield tubular. The ICD is typically installed and combined with a sand screen in an unconsolidated reservoir. If screen is required, the reservoir fluid is produced through the sand screen and into the flow chamber. The flow continues through a set of tubes, creating a pressure drop, and then into the pipe through a set of ports. Tube length and inner diameter are designed to give the pressure drop needed for optimum completion efficiency.

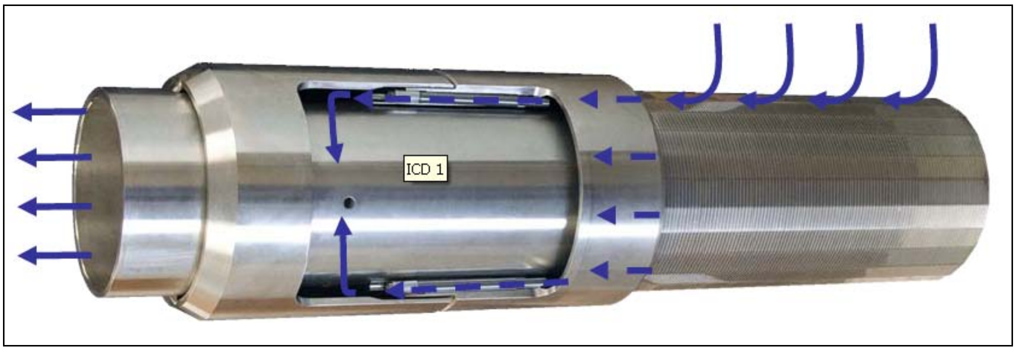


Figure 38: Halliburton EquiFlow ICD - Flow path.

4.5 Positive and negative comments about smart wells and ICD

The advantages of smart wells can be summarized as below:

1- Reduced well intervention costs (The ability to reconfigure wells remotely reduces the need for physical intervention).
2- Optimized hydrocarbon production
3- Control of water production
4- Selective zonal control
5- Remotely monitor the well by down-hole control devices and sensors.
6- Improved control of water injection
7- Increased ultimate recovery (because of controlled injection) and accelerated production.
8- Increased operational flexibility to the petroleum production.
9- Better reservoir description(divided into sections)
10- The Inflow Control Device has easy installation, no added rig time, and limited additional costs

Disadvantages smart well:

1- Reliability (harsh downhole environment)
2- Increased costs(additional investments)
3- Temperature limited
4- Metallurgy selection limited
5- Sealing technologies
6- ICD not adjustable
7- ICD rate dependent

In general, Inflow Control Devices can be either beneficial or detrimental to production, strongly depending on the reservoir condition, well structure and completion design. Realizing that reservoir conditions will change during the life of a well, the impact of an inflow control device is a function of rate (time).

Because of the high intervention costs of smart wells, reliability is vital. The effect of smart wells on net present value has to be carefully calculated because of the additional investments.

Advantages DIACS and multilateral wells:

1- Branch control
2- More efficient sweep

3- Better reservoir drainage
4- Reduced intervention costs
5- Environment-friendly (less produced water).
6- Reduced discharges of produced water (less water production => reduced need for chemical treatment =>less total amount of discharge).

Disadvantages DIACS:

1- Reliability
2- Lifetime

A huge disadvantage for multilateral wells is that when the branches of the well are drilled it is not possible to go through the first drilled branch again. This means that the first branch should be drilled and completed before drilling the next branch. Meanwhile it is not possible to go through the older branch and fix it in case of technical problems.

4.6 Five-branched Smart Well - Simulation

Increasing exposure to the reservoir by increasing the ther number of the drainage point was achieved by the use of a five branched well with control (smart well). The new oil producers in the extended case were replaced by a five-branched well with control on the gas-oil ratio, GOR (as a parameter) for each segment of the branch, using the ACTION keyword. This is done in WCONPROD of the INCLUDE file as shown in the box below.

```
WCONPROD
'NILS'  'OPEN'    'GRAT'   800.000   1*  1000000.000  3*   90.000  7   6*  /
/
ACTIONS
ACT1 NILS 1 SGOR > 10000 /
WELOPEN
NILS     SHUT   20      85       1  /
/
ENDACTIO
ACTIONS
ACT2 NILS 2   SGOR > 10000 /
WELOPEN
NILS    SHUT 21         85       1 /
/
ENDACTIO
ACTIONS
ACT3 NILS 3   SGOR > 10000 /
WELOPEN
NILS    SHUT 21         85       2 /
/
ENDACTIO
```

Figure 39: Eclipse - use of ACTION keyword.

The gas oil ratio was varied until a suitable value that reflects the positive control of the gas oil ratio since the field is limited by gas breakthrough.

Five-branched Smart Well

The 3-D view of the five-branched smart well is shown in Figure 40.

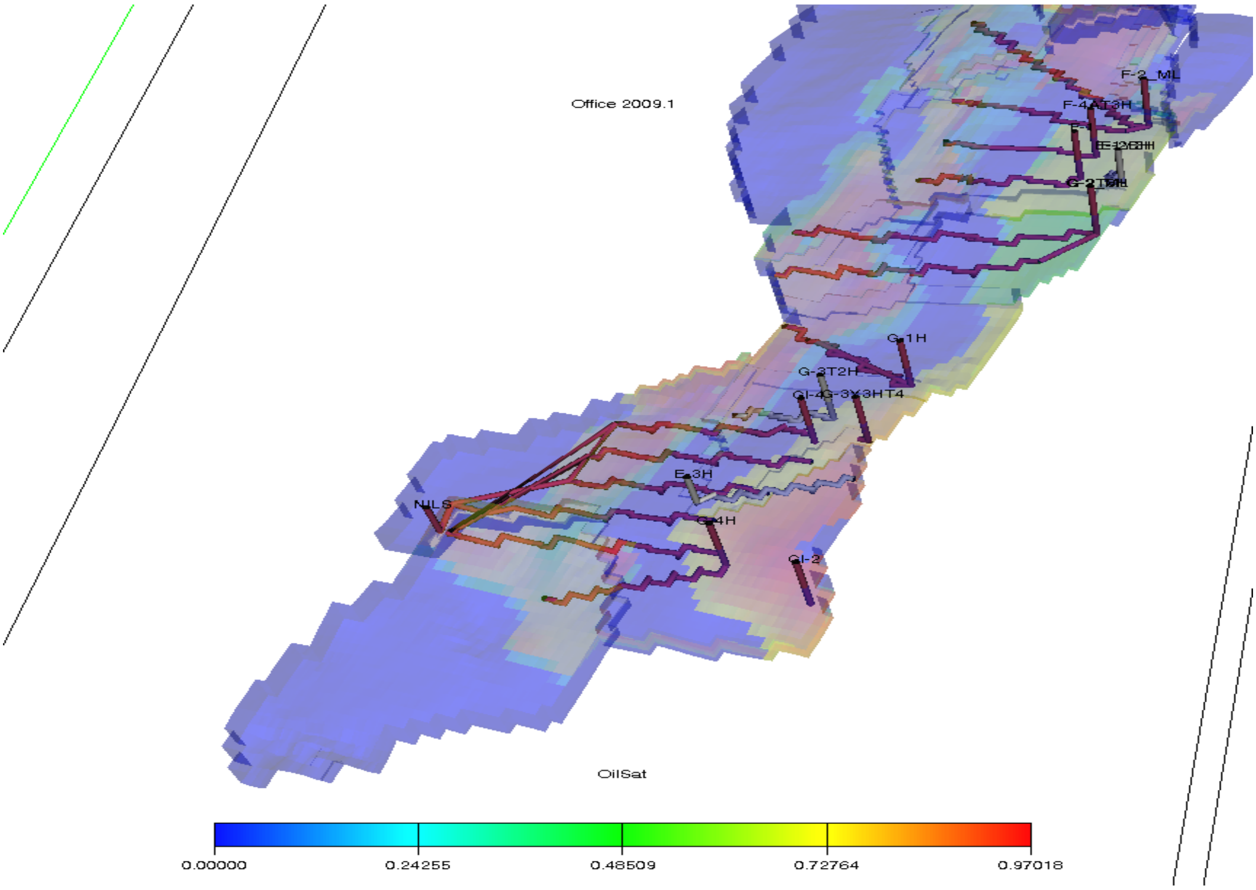


Figure 40: 3-D view of the Smart Well.

4.6.1 Comparison

The production lifetime was extended to 2035. Comparing the Well Oil Production Total for the smart well (NILS) with the single well (W1) and the two-branched well (W2W3), there will be a marginal accelerated increase in the oil production total by the smart well (NILS). In January 2035, NILS will produce 3628722,5 Sm^3 compared to W1 and W2W3 which will produce 1158077,1 Sm^3 and 1402267,5 Sm^3 respectively as shown in the Figure 41.

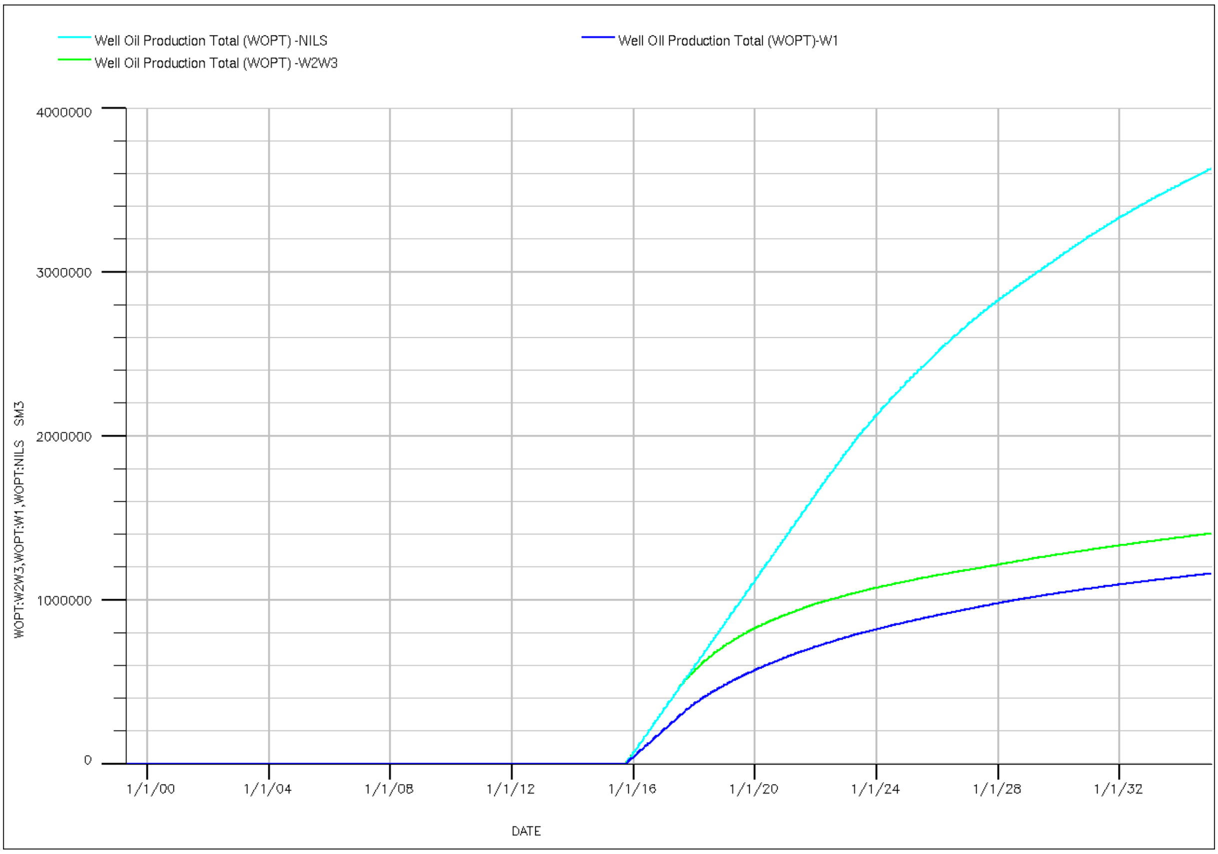


Figure 41: Well Oil Production Total for NILS, W1 and W2W3.

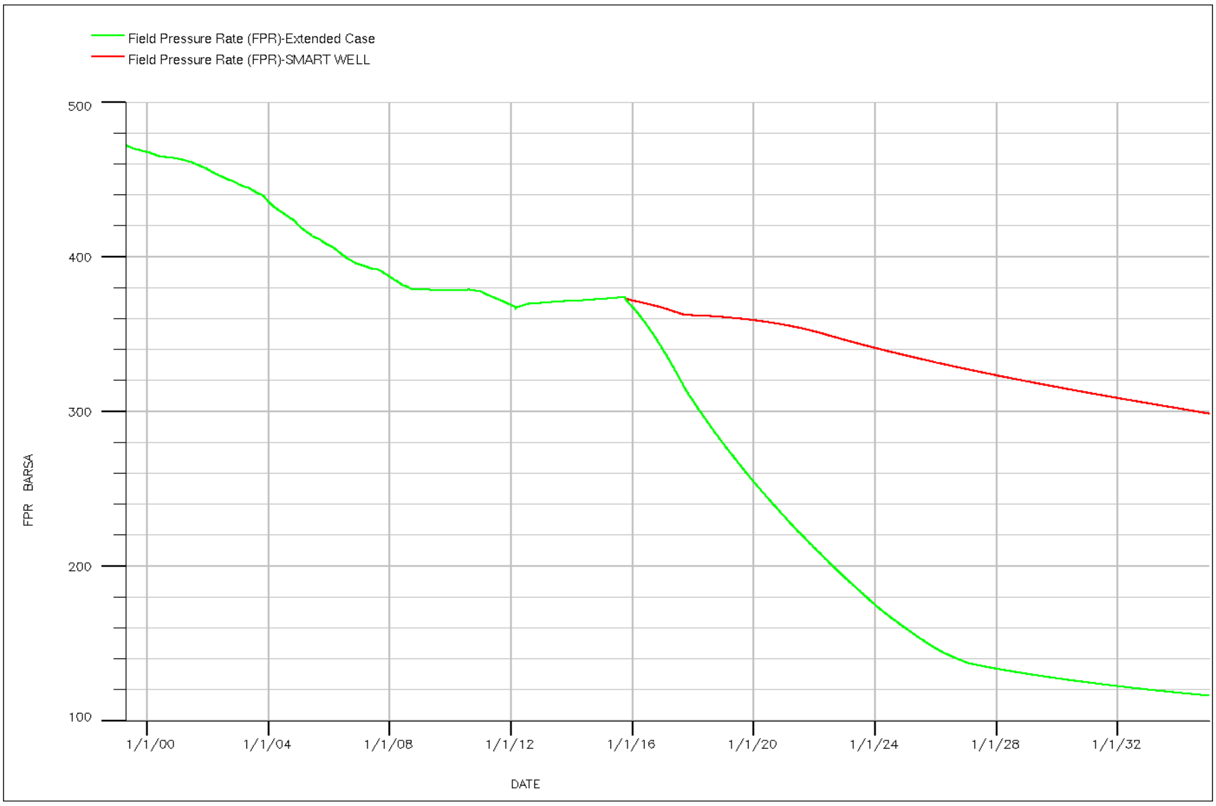


Figure 42: Field Pressure Rate for Smart Well case and Extended Case.

There is an even and gradual decrease in the field pressure rate for the smart well (shown in the Figure 42 above) compared to the extended case with drastic decline. At January 2035, the pressure rate of the smart well field (298,3 barsa) will still be above bubble point (220 barsa) which by implication is undersaturated. This is due to minimal drawdown synonymous with smart well thereby prolonging the lifetime of the field. The field pressure rate of the extended case at January 3035 (115,96 barsa) will be below the bubble point whereby require more pressure support to produce.

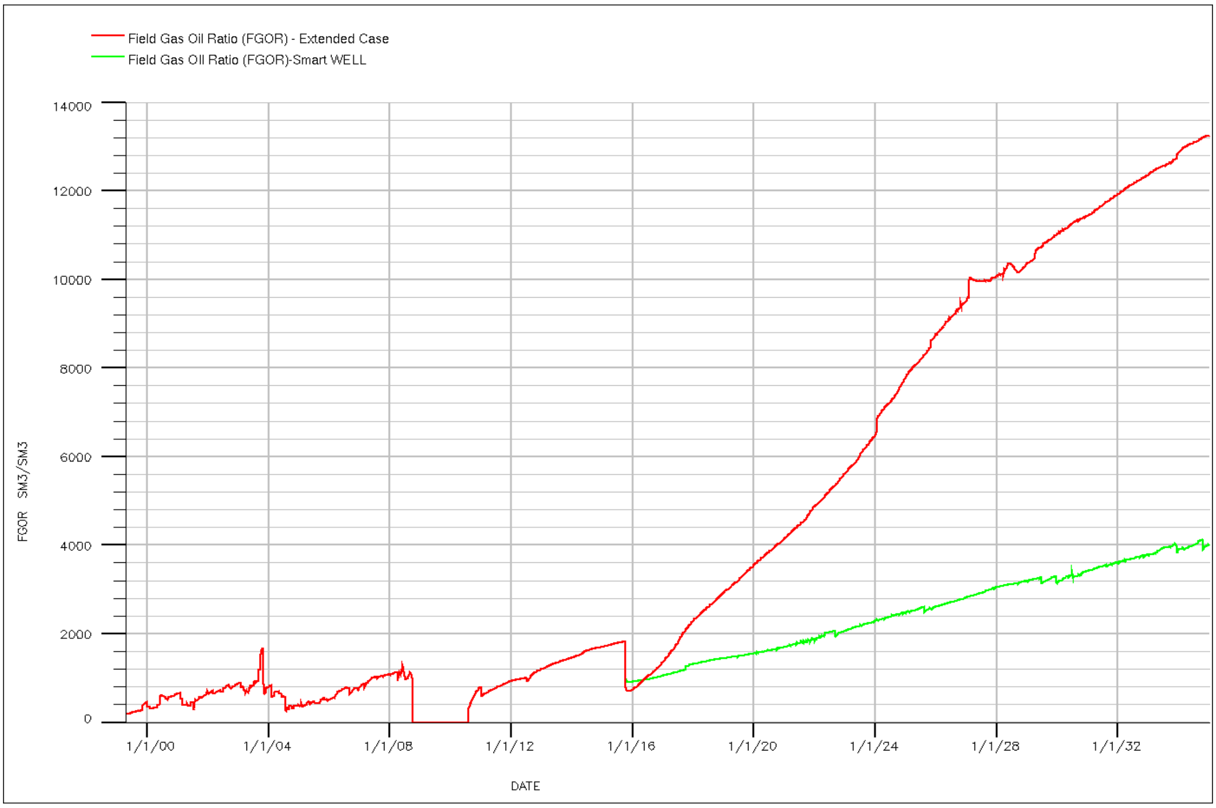


Figure 43: Field Gas-Oil Ratio for Smart Well case and Extended Case.

From Figure 43, the gas oil ratio for the smart well field is less compared to the extended case. In the simulation, the gas oil ratio parameter (selected amongst other parameters) for all the branches of the smart well were controlled using the ACTION keyword. And from Figure 42, the pressure of the smart well field is still above bubble point which implies that the field is undersaturated with the gas dissolving in the oil thereby producing less gas to oil ratio. At January 3035, the field gas ratio for the smart well and extended case is 3995,18 Sm^3/Sm^3 (~30% of the extended case) and 13250,66 Sm^3/Sm^3 respectively.

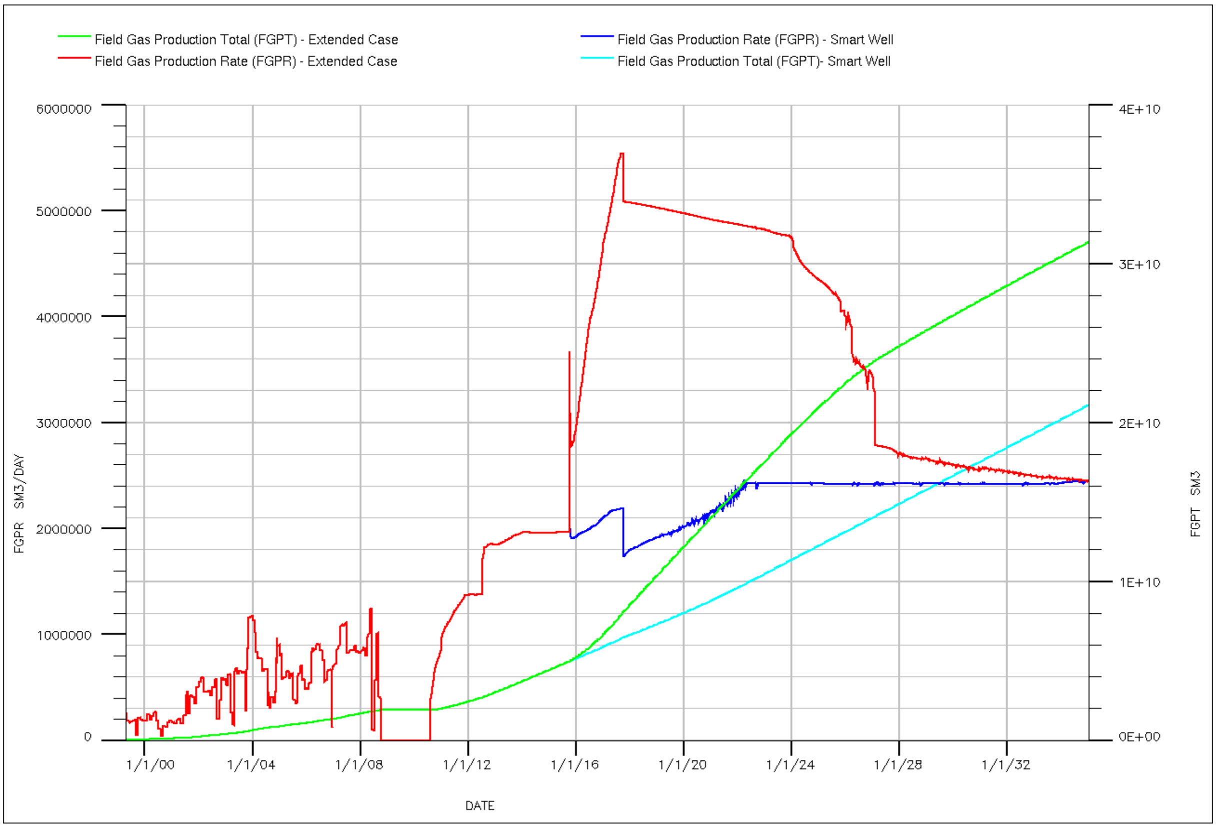


Figure 44: Field Gas Production Total and Field Gas Production Rate for Smart Well case and Extended Case.

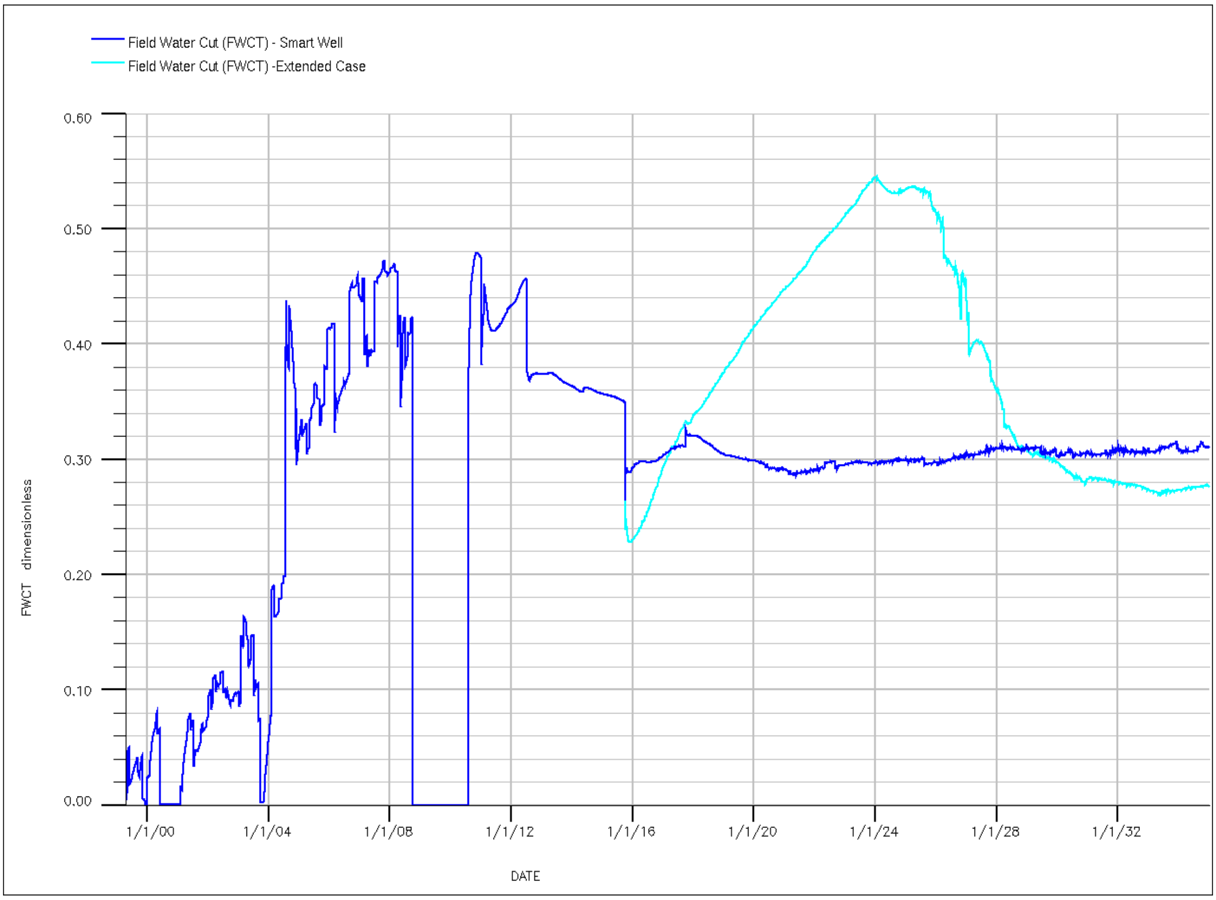


Figure 45: Field Water CuT for Smart Well case and Extended Case.

From Figure 44 and Figure 45, the gas production rate, gas production total and water of the field for the extended case is higher compared to the smart well field. As the pressure of the field decline as in the extended case more free gas will be produced. But as seen in Figure 44, the production rate of the gas decreases as the pressure of the field falls below the bubble point. The gas production rate and water cut of the smart well field are almost constant. The water cut is approximately 30%.

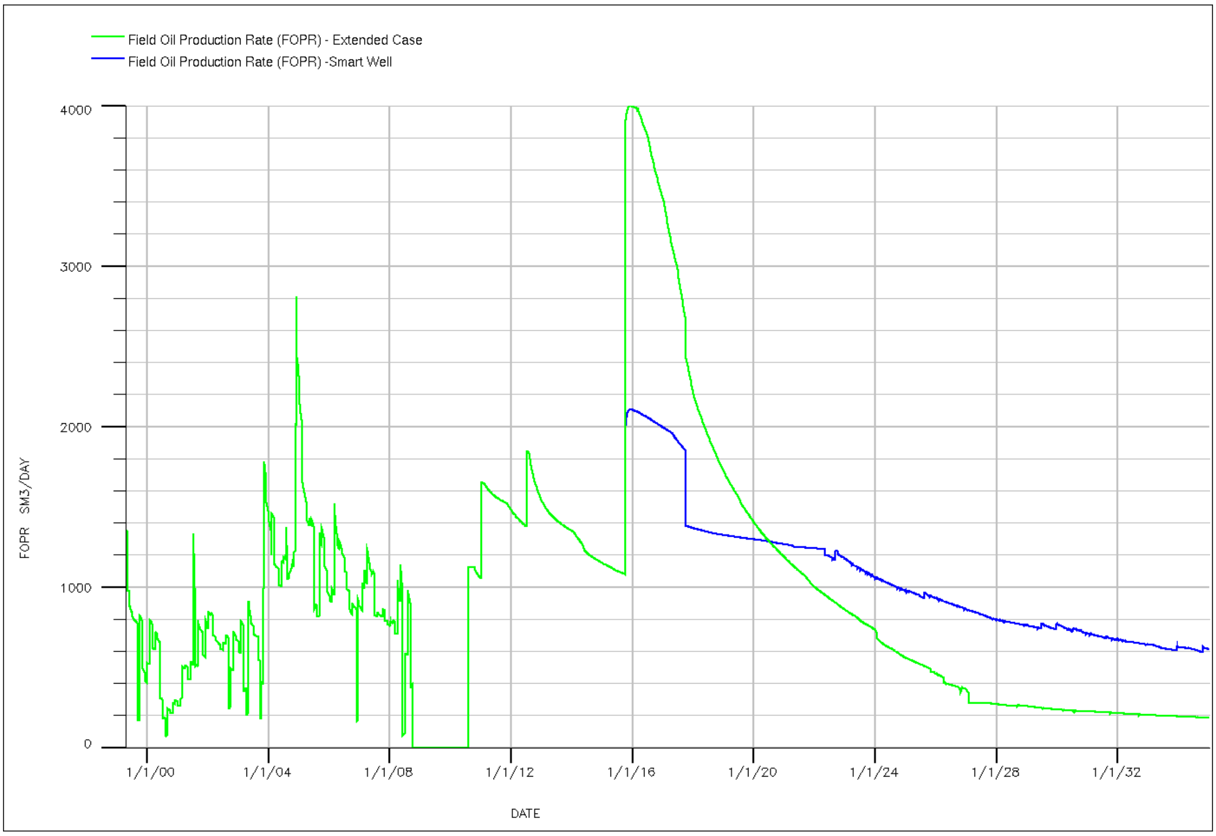


Figure 46: Field Oil Production Rate for Smart Well case and Extended Case.

In 1/10/2015 in the extended case two new gas injectors are introduced to the field, production rate will be 1078.93 Sm^3/Day. With the pressure support from gas injection, the oil production rate will increase sharply and plateau at 3996.9 Sm^3/Day on 04 December 2015. As shown in Figure 46 above, the production rate of the extended case will decline sharply after this period. This is attributed to the quick decline in pressure of the field; also one of the producers (G-4H) was shut down on 01/10/2017. The smart well field oil production rate was initially less (1/10/2015 – 04/07/2020) compared to the extended case. Due to the gradual decrease in pressure of the smart well field which is still above bubble point, the production rate improves compared to the extended case that was on decline. At January 2035, the production rate of the smart well field and the extended case are 611.8 Sm^3/Day and 184.5 Sm^3/Day respectively.

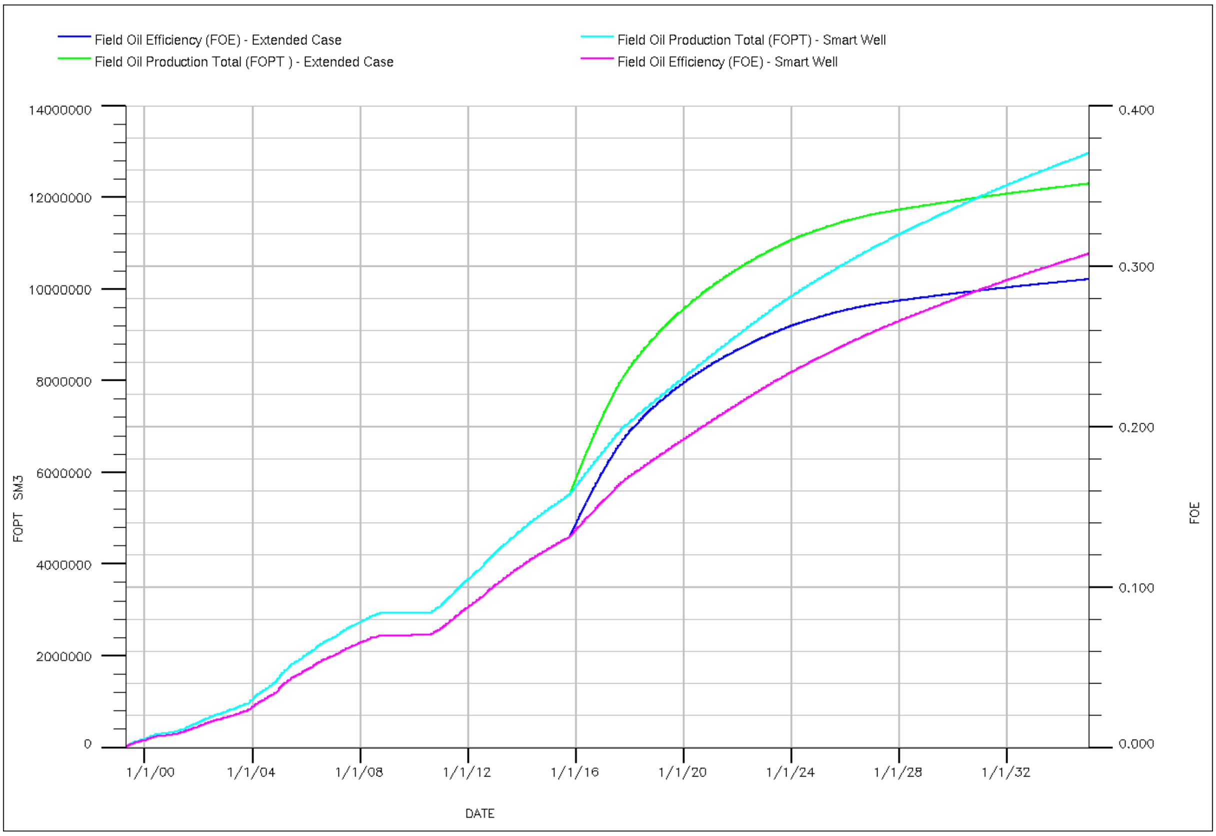


Figure 47: Field Oil Production Total and Field Oil Efficiency for Smart Well case and Extended Case.

The field oil production total (FOPT) and the recovery factor (FOE) of the extended case is higher compared to the smart well case initially (i.e 01/01/2016 – 12/11/2030)as shown in Figure 47 above. But, smart well has a steep increase compared to the extended case.

The long-term plan indicates a recovery factor (FOE) of approximately 31% and 29% for the smart well and extended case respectively by January 2035. The production total is approximately $129x10^5$ Sm^3 and $123x10^5$ Sm^3 for the smart well and extended case respectively.

4.6.2 Conclusion

From Figure 41, the Smart well is justified by more efficient sweep and reservoir drainage. The drilling of four new branches will increase cost but this increase in cost is much smaller than the cost of drilling and completing four main bore. The increase in cost of the branches is also compensated by the increase in oil produced. Also, there is less drawdown, water and gas breakthrough compared to the extended case. With the smart well it will be possible to produce from the field over a longer time period, because of the higher pressure rate and more stable production rate.

4.7 ICD - Simulation

In this case the aim is to make a simulation of an Inflow Control Device (ICD). Well W1 was chosen as the well to get an ICD. The reason for this is that well W1 is a single branched well, thus it is easier to control and to see the results. The method used was to implement the keyword WSEGSICD. The parameter ICD strength was set to 0.00021, while all other parameters were set to default values. The segments 17 to 22 had ICDs. Apart from this all wells and injectors were the same as in the extended case. The results will be compared to the results from the extended case. The well W1 with ICD is called WICD.

4.7.1 Comparison

Well WICD vs. W1

The updated well WICD produce oil at a rate of 500 Sm3/day, the same as well W1. In September 2017 the production rate of well W1 drops, while well WICD production rate drops in August 2018. WICD produce more than W1 until February 2025 when the production rate of WICD has a new drop and the well is shut down 11/1/2026, see Figure 48.

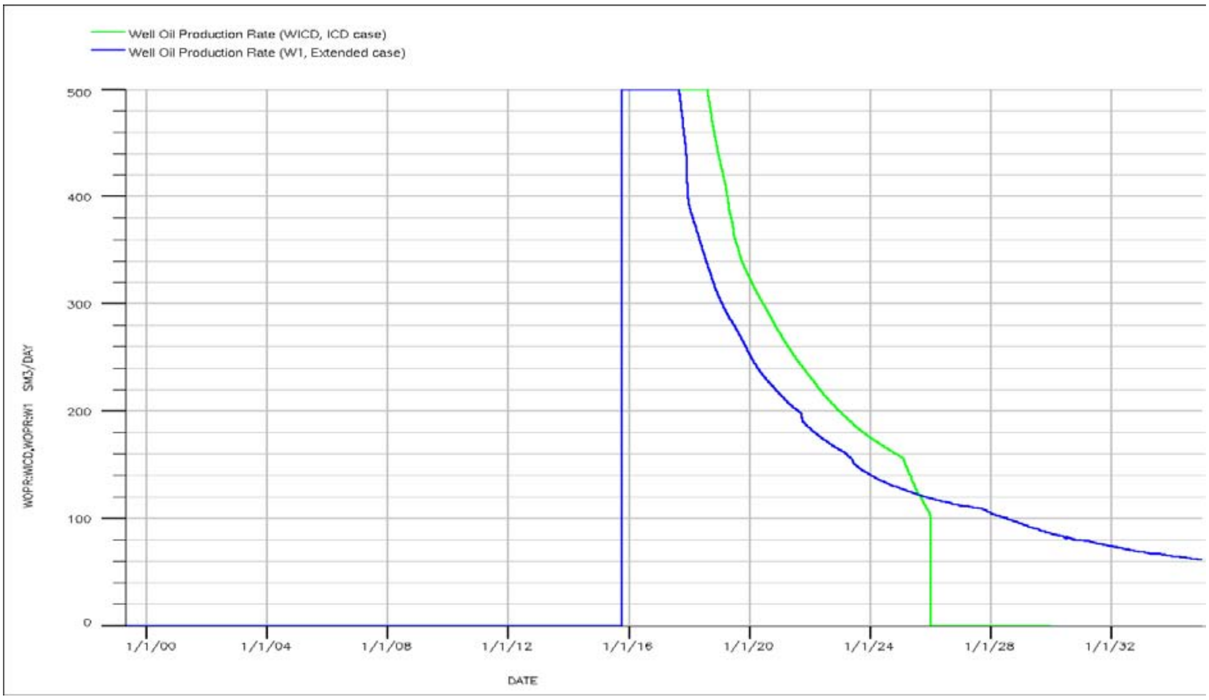


Figure 48: Well Oil Production Rate of wells WICD and W1.

The well WICD produce gas at a slower rate than well W1, and WICD reaches the peak of 1 000 000 Sm3/day at 9/8/2018, about a year after W1. The peak production rate for WICD drops in February 2025 like the oil production and is shut down 11/1/2026, see Figure 49.

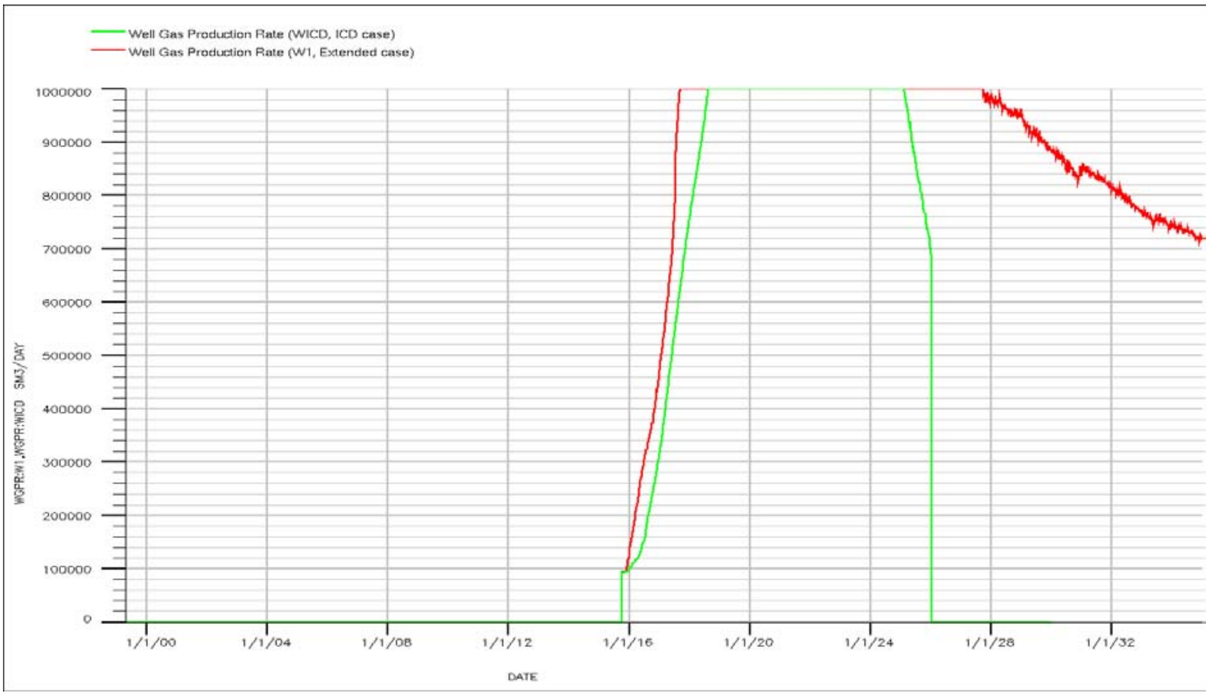


Figure 49: Well Gas Production Rate of wells WICD and W1.

The water cut of the two wells can be seen in Figure 50. The water cut of WICD has its first peak at approximately 30% at the start of production. It starts to increase at a high rate in early 2016 before slowing down at the beginning of 2018. In late 2020 the water cut again starts to rise until it reaches its new peak at almost 56 % in February 2025. The well WICD is shut down 11/1/2026. The water cut for WICD seems to be around 20 %-points over the water cut of the well W1, all the time from start of production to February 2025.

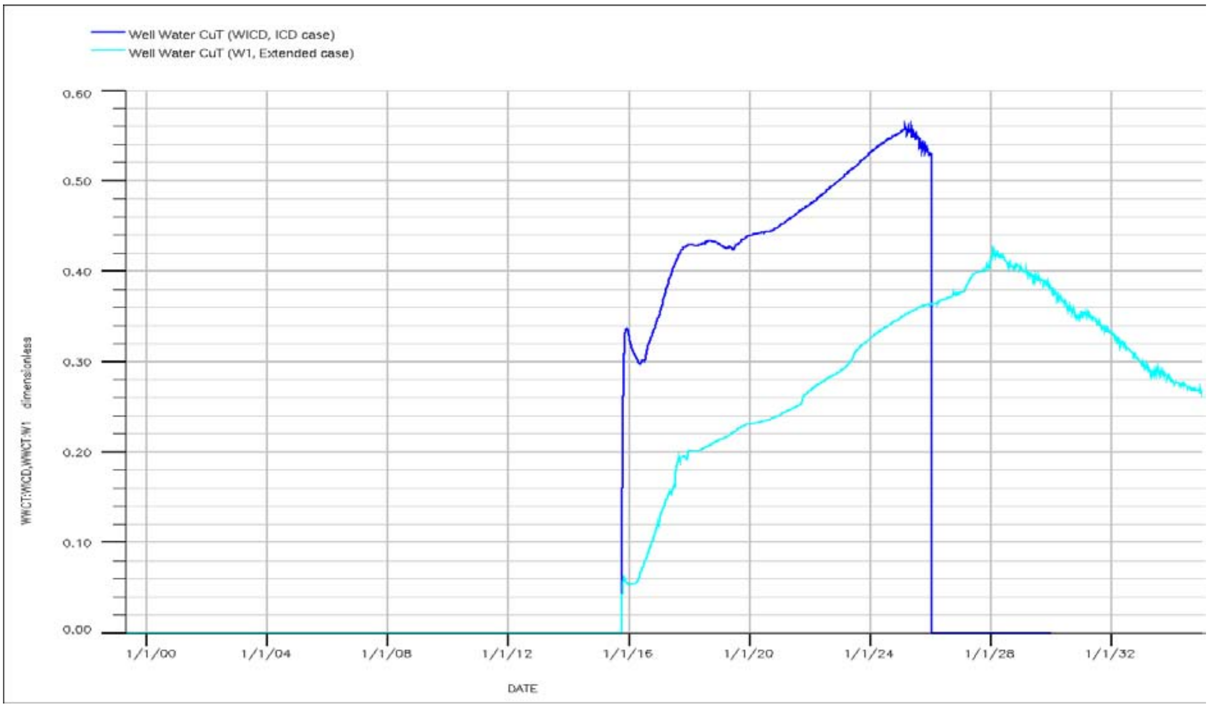


Figure 50: Well Water CuT of wells WICD and W1.

The bottom hole pressures of the two wells are very much the same. WICD has a bottom hole pressure of approximately 10 barsa lower than W1 for the time period between start of production and the well shut down at 11/1/2026. This is displayed in Figure 51.

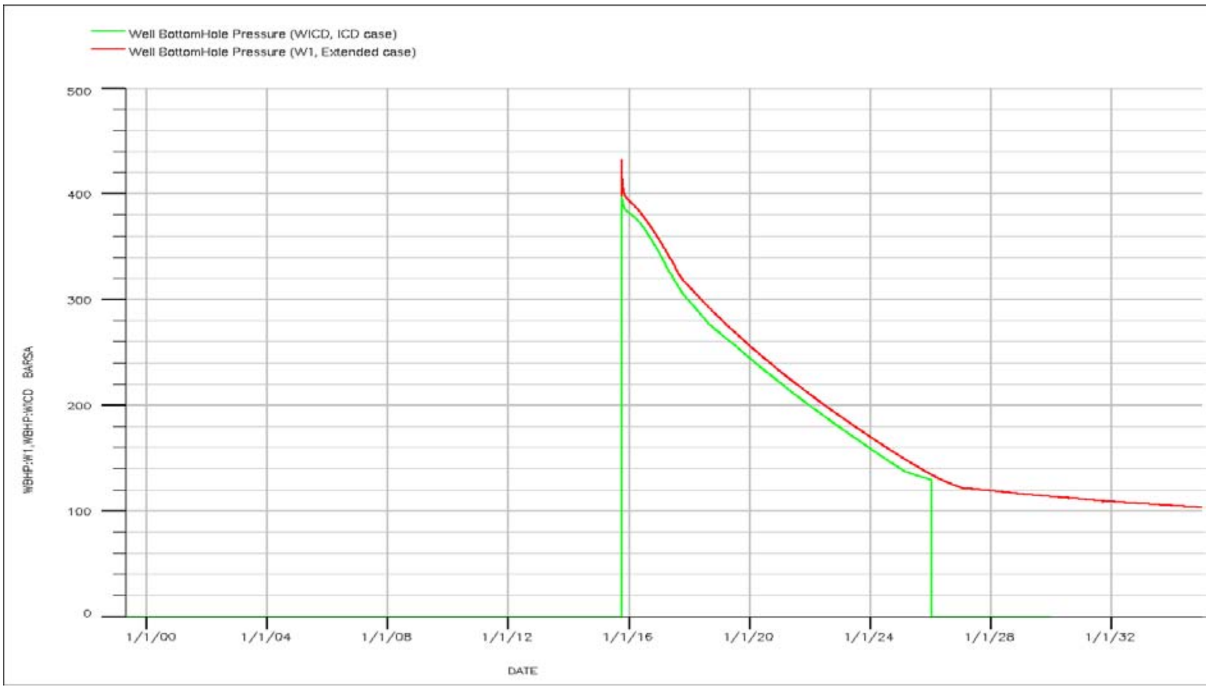


Figure 51: Well Bottom Hole Pressure of wells WICD and W1.

ICD case field vs. Extended case field

The field oil production rate, field gas production rate, water cut and field oil production for the two cases is very similar until the well WICD in the ICD case shuts down 11/1/2026. This is displayed in Figure 52, Figure 53, Figure 54 and Figure 55.

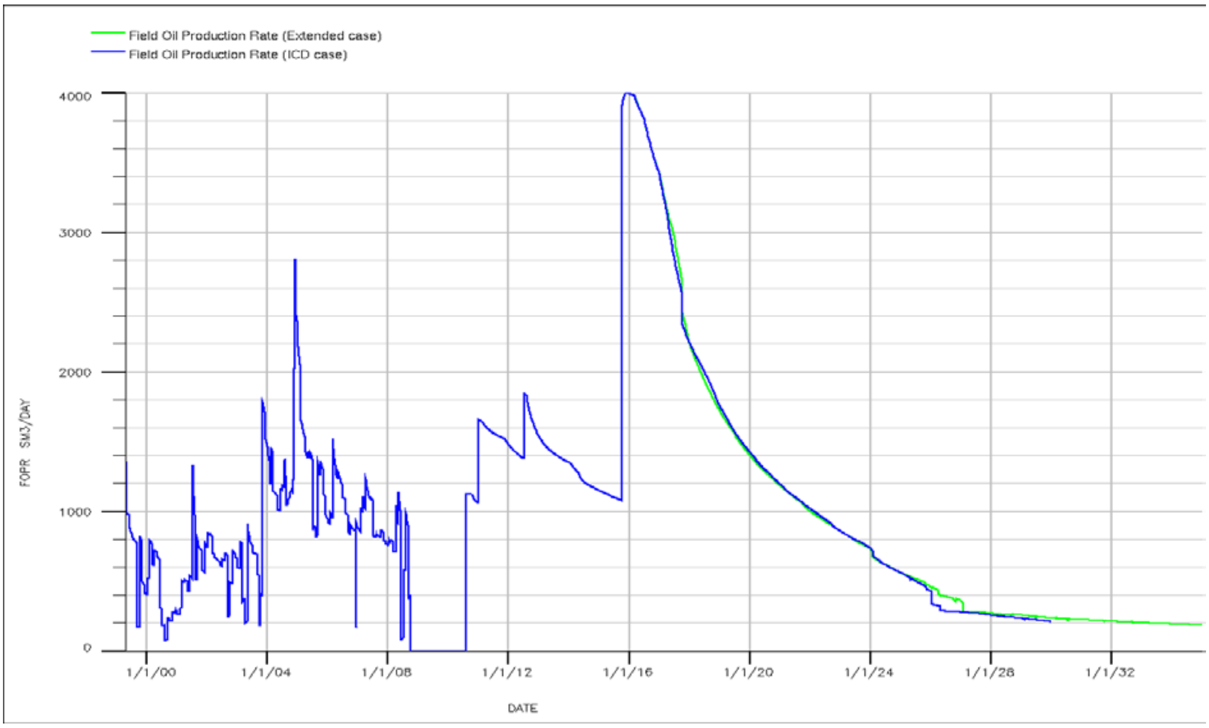


Figure 52: Field Oil Production Total of ICD case and extended case.

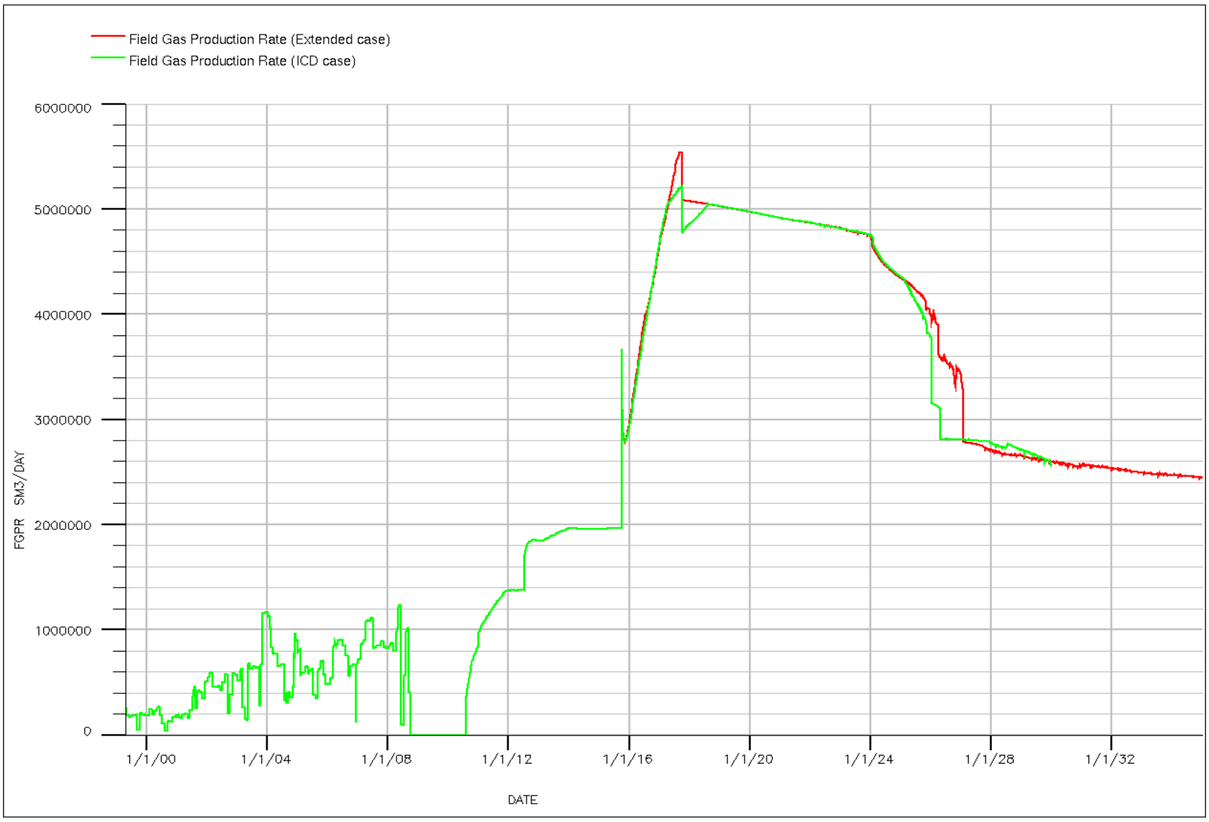


Figure 53: Field Gas Production Rate of ICD case and extended case.

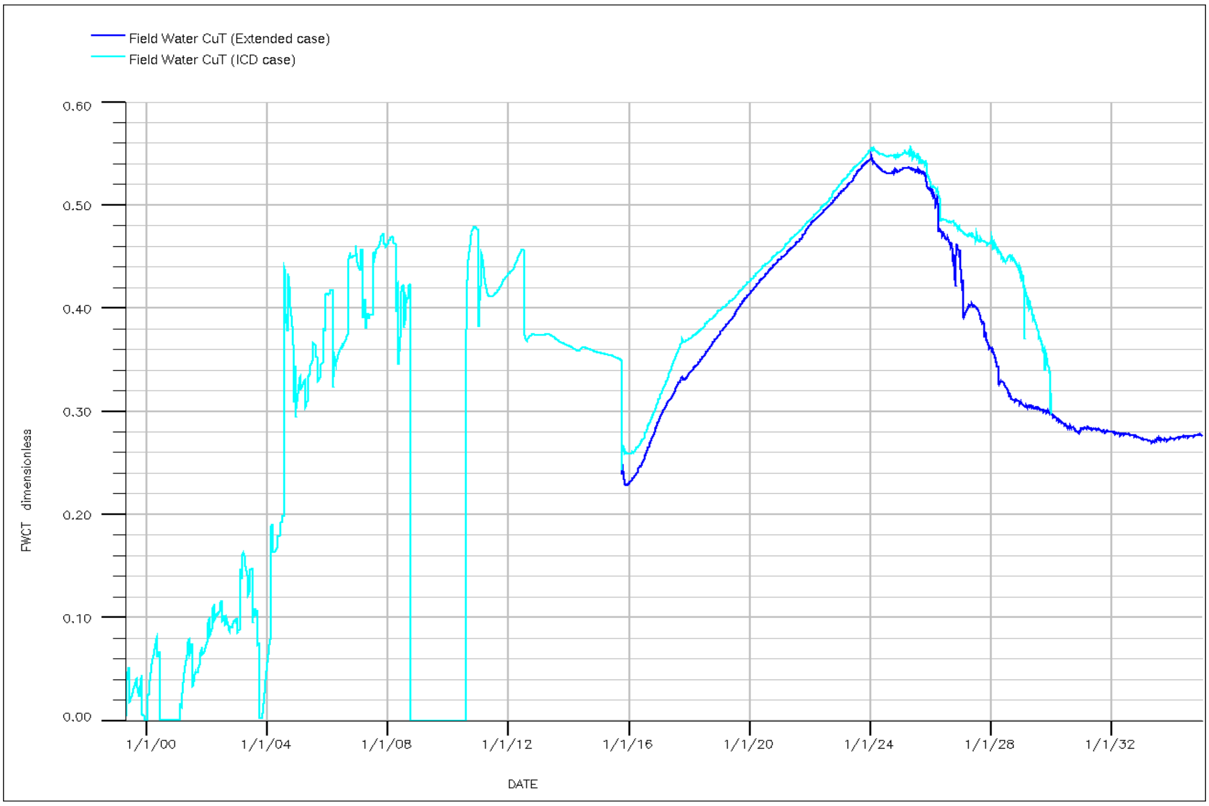


Figure 54: Field Water CuT of ICD case and extended case.

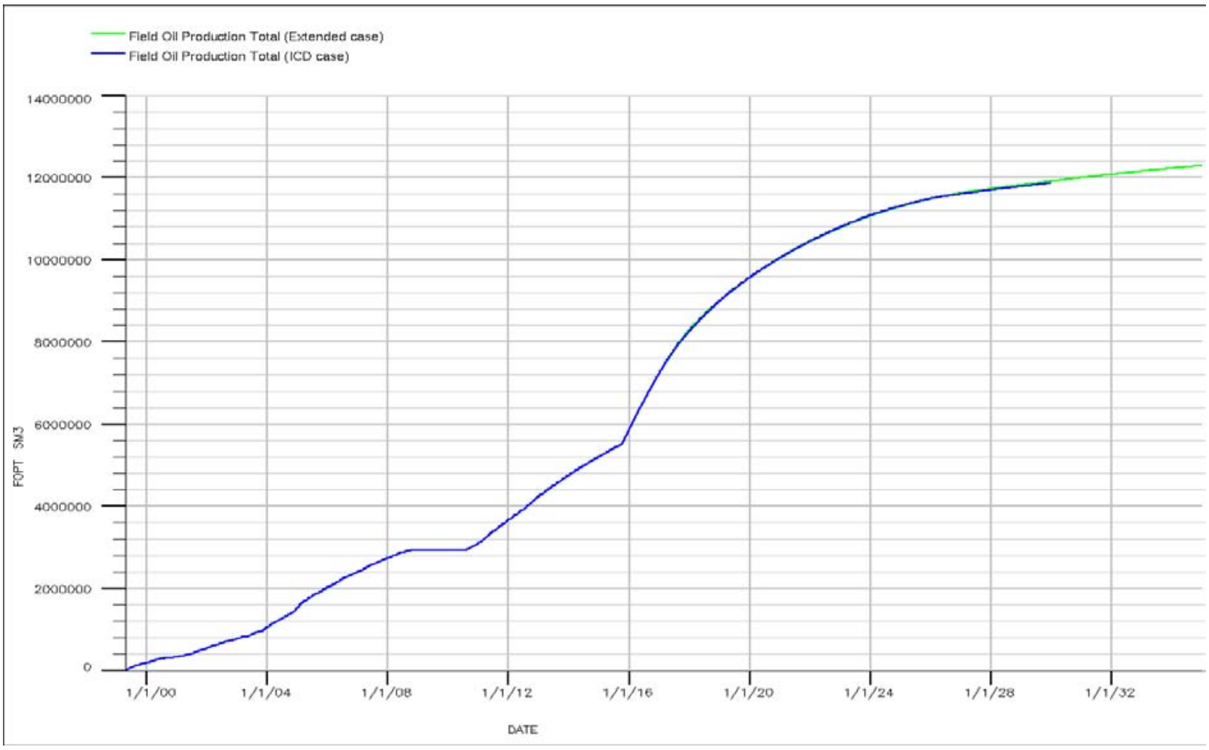


Figure 55: Field Oil Production Total of ICD case and extended case.

The wells WICD and W1 are only one of nine producers in their respective case. Therefore the difference between the two cases would never be dramatic. However, there is only an insignificant difference in Field Oil Production Rate, Field Oil Production Total and Field Water Cut, even less than expected from the oil production rate and water cut differences of WICD and W1 (until WICD shuts down). This indicates that another well apart from WICD experience different production rates from extended case to ICD case.

Well W2W3 (ICD case) vs. W2W3 (Extended case)

The well oil production rate in the ICD case is lower than the well oil production rate in the extended case, see Figure 56.

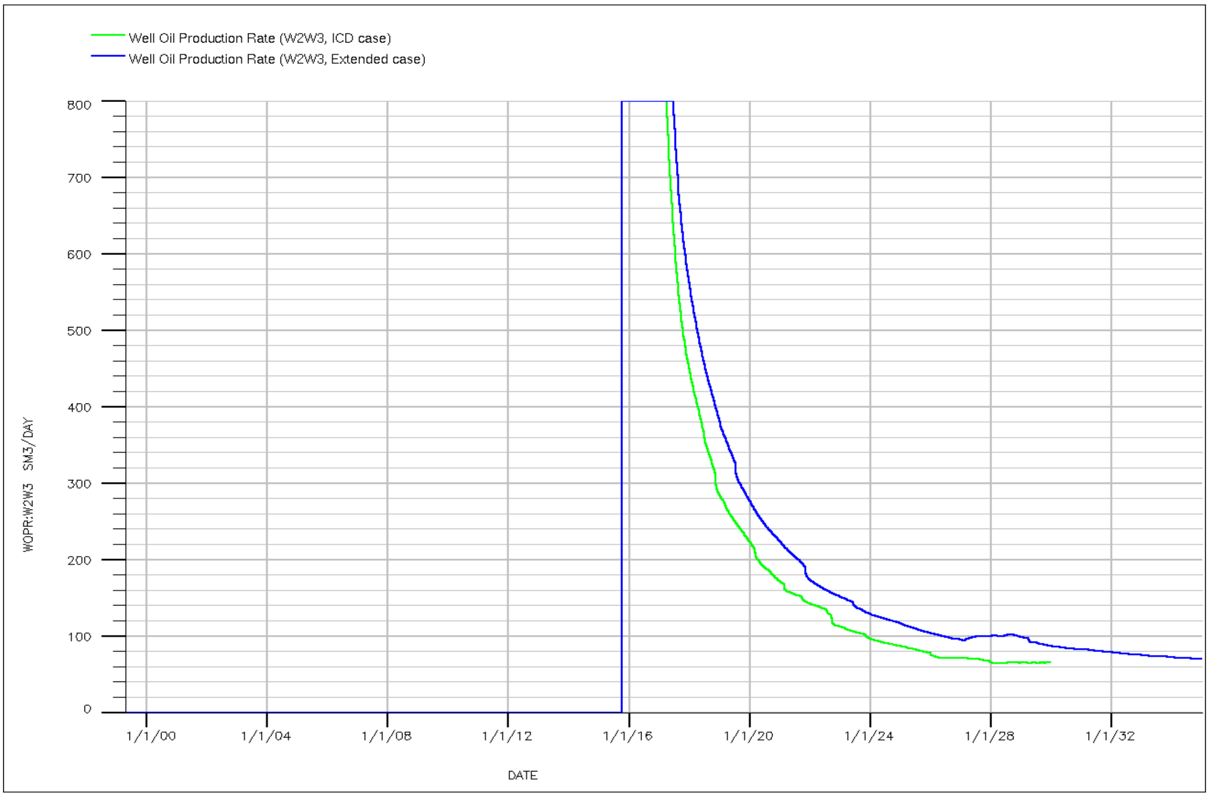


Figure 56: Well Oil Production Rate of well W2W3 in the ICD case and the extended case.

The increase in Well Gas Production Rate in the two cases is almost the same other that the production rate in the ICD case reaches the plateau almost 3 months before in the extended case. This is displayed in Figure 57.

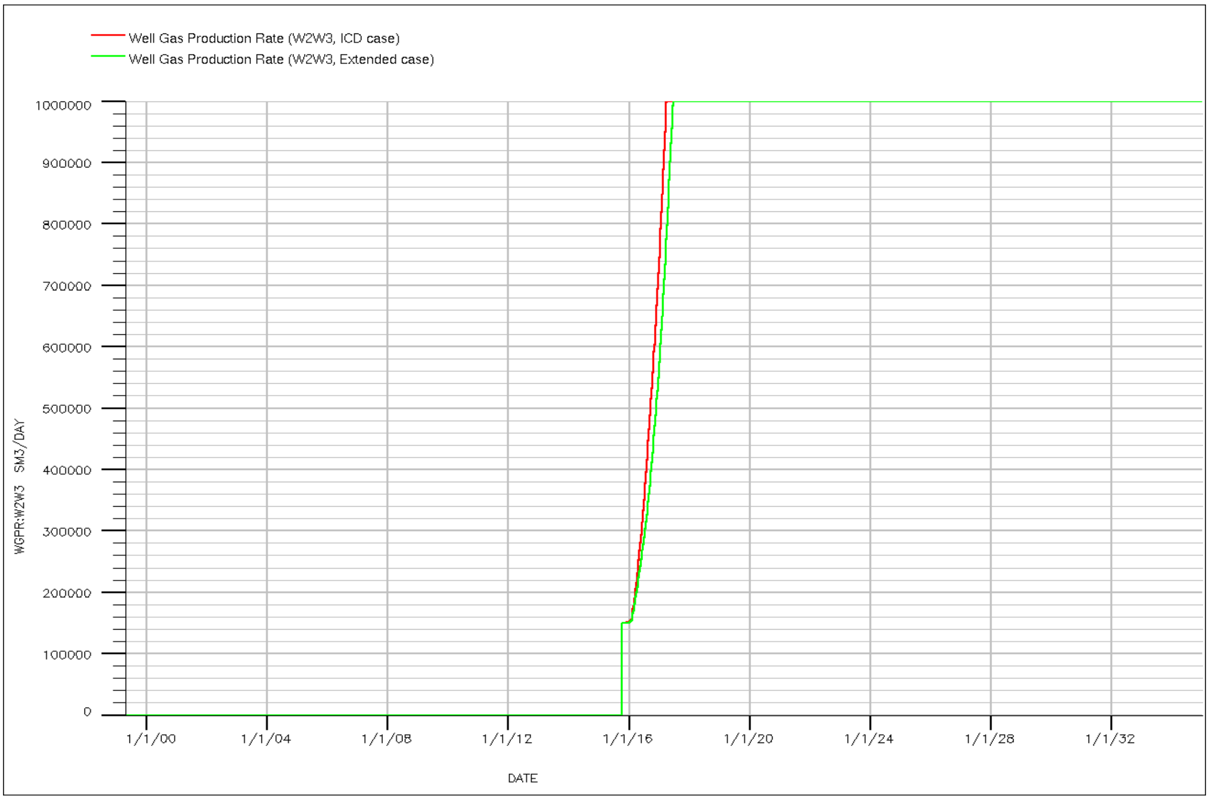


Figure 57: Well Gas Production Rate of well W2W3 in the ICD case and the Extended case.

The water cut in the two cases is different, see Figure 58. W2W3 in the ICD case produce less water than in the extended case. When the well WICD in the ICD case is shut down there is a fall in the water cut of the well W2W3 (ICD case).

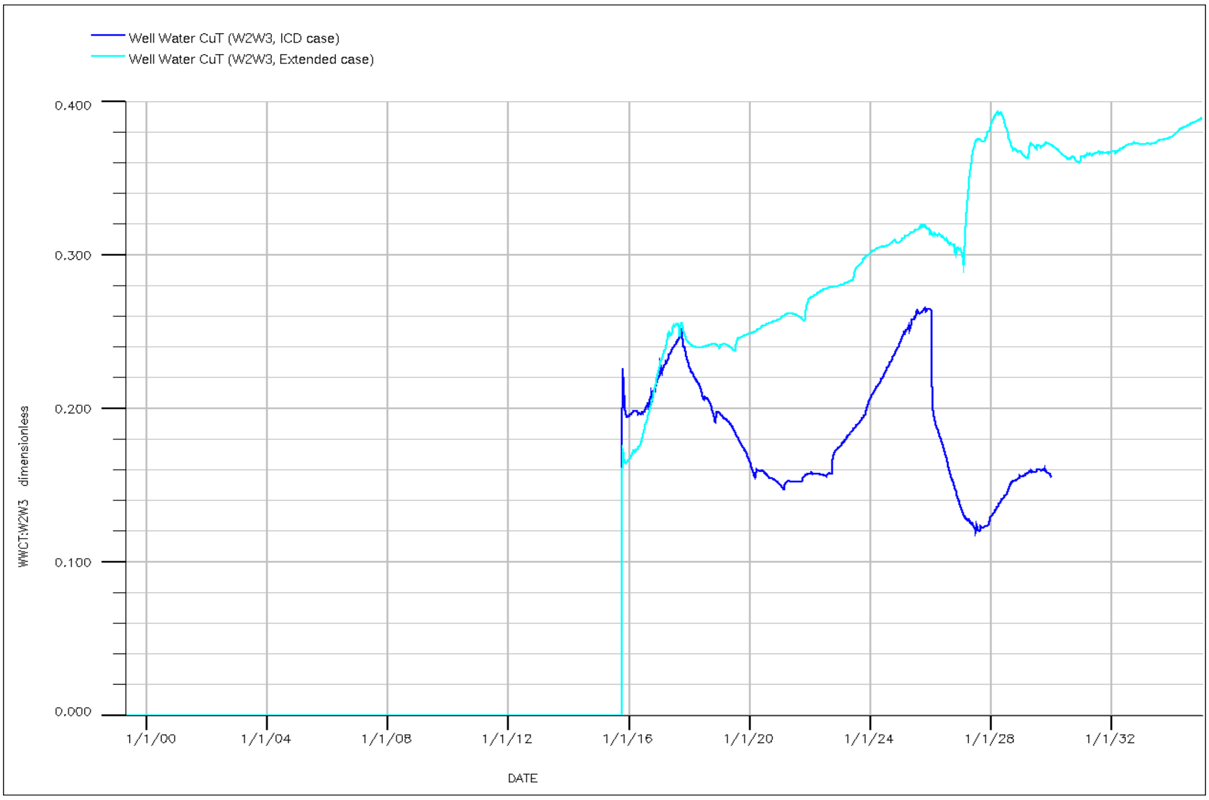


Figure 58: Well Water CuT of well W2W3 in the ICD case and the Extended case.

4.7.2 Conclusion

The wells WICD and W1 are only one of nine producers in their respective case. Therefore the difference between the field production rates of two cases would never be dramatic. However, there is only an insignificant difference in Field Oil Production Rate, Field Oil Production Total and Field Water Cut, even less than expected from the oil production rate and water cut differences of WICD and W1 (until WICD shuts down). This indicates that another well apart from WICD experience different production rates from extended case to ICD case. There is negative change in oil production rates of well W2W3 from Extended case to ICD case, while WICD experience the opposite change, suggest that the two wells are competing over the same oil. This is supported by the fact that the wells lie relatively close to each other. The increase in oil production rate of WICD compared to W1 indicates that an ICD could be a good solution to increase the oil recovery of the field. At the same time ICDs should either be placed at all or none of the wells/branches or at least at a certain distance between ICD-branch and non-ICD-branch. The increased water cut in WICD compared to W1 indicates a problem, since an ICD is supposed to do the opposite. The reason for the decrease in production of the well WICD in February 2025 and the shutdown at 11/1/2026 is not known. Due to time limitations this has not been investigated much.

4.8 Economic Evaluation

In the following chapter an Economic Evaluation will be done, for the comparison between the multilateral and the reference case. The ICD is not economic evaluated because it was done to deliver a small insight into the effect of an ICD.

4.8.1 Economic Assumptions

The general assumptions are as stated in 3.3.1 Assumptions General, the assumptions and facts for the Alternative 1/2 of Part B will be mentioned below.

<u>Assumption - Alternative 1B – Platform</u>

The assumptions for Alternative 1 are as followed:

- Capex for Wellhead Platform: 4 000 MNOK
- Costs for Drilling: 350 MNOK
- Plugging and abandonment: 300 MNOK
- Opex cost: 91 NOK/bbl oe

The Investment is taken in 2014 and the Platform is abandoned in 2030.

<u>Assumption - Alternative 2B – Subsea Solution</u>

The assumptions for Alternative 1 are as followed:

- Capex for two subsea templates: 1 500 MNOK
- Costs for Drilling: 350 MNOK
- Plugging and abandonment: 200 MNOK
- Opex cost: 111 NOK/bbl oe

The Investment is taken in 2014 and the template is abandoned in 2030

4.8.2 Economic Results Part B

In the following part the economic result from Part B are elaborated and shown.

<u>Alternative 1B</u>

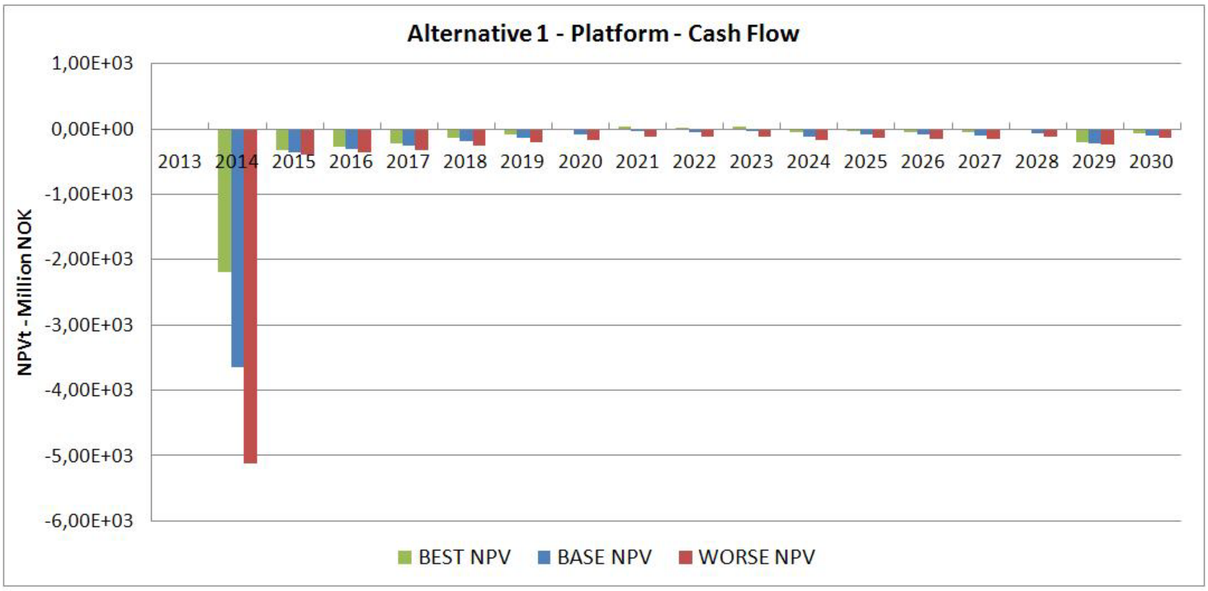


Figure 59: Alternative 1 - Part B - yearly NPV

Figure 59 shows the cash flow of the production years, as it can be seen nearly all years and different cases got negative revenue. The high negative revenue in 2014 is related to the investment costs of the Platform. The yearly bad results are leading to a cumulative NPV as it is shown in Figure 60, which highlights the unprofitable economic results.

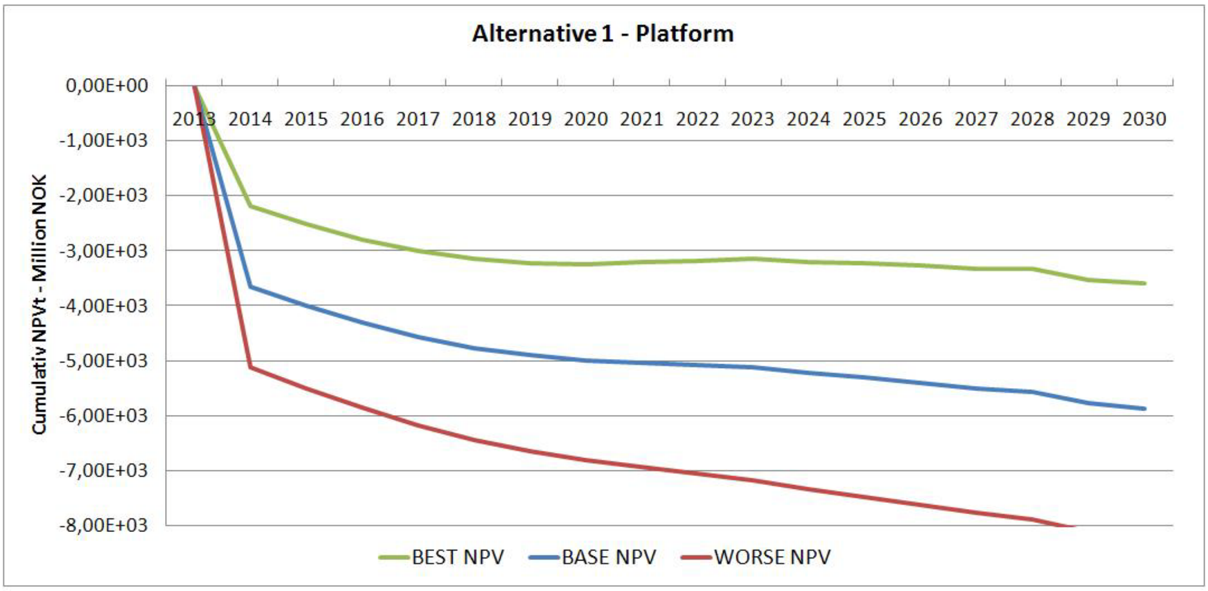


Figure 60: Alternative 1 - Part B - Cumulative NPV

The sensitivity of the Alternative 1B can be described as followed. A change of the capex cost with 40 % would influence the NPV up until 25% (Figure 61). The gas and oil opex got an even lower influence. The highest influence is achieved by the gas and oil price, were a change with 5 % leads to a change with nearly 5 % of the NPV.

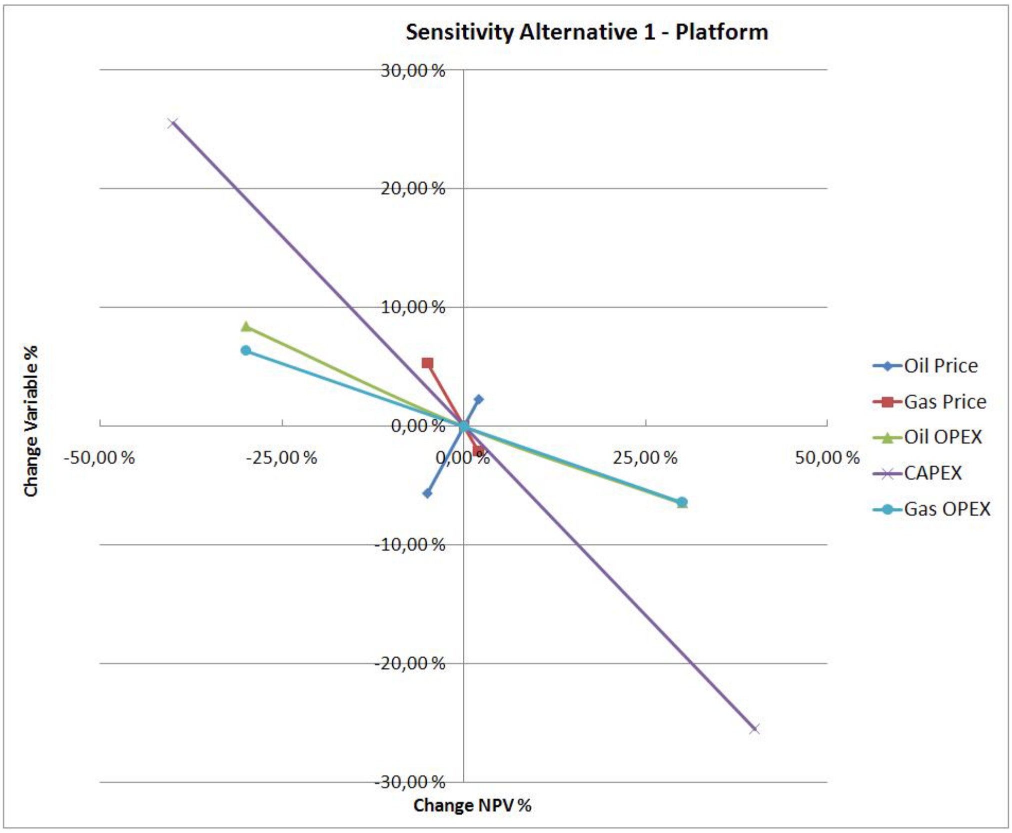


Figure 61: Alternative 1 - Part B - Sensitivity

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Alternative 2B

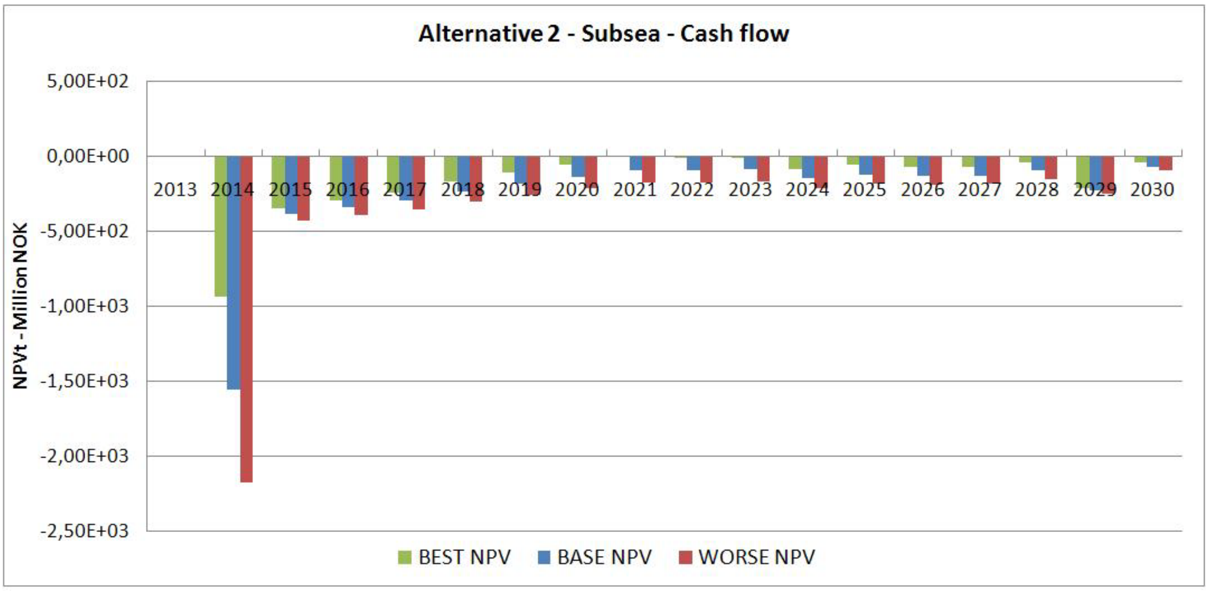

Figure 62: Alternative 2 - Part B - yearly NPV

Alternative 2B also shows a highly negative NPV throughout the years (Figure 62). In none of the three cases a positive yearly cash flow can be achieved, which leads to the results as it is shown in Figure 63.

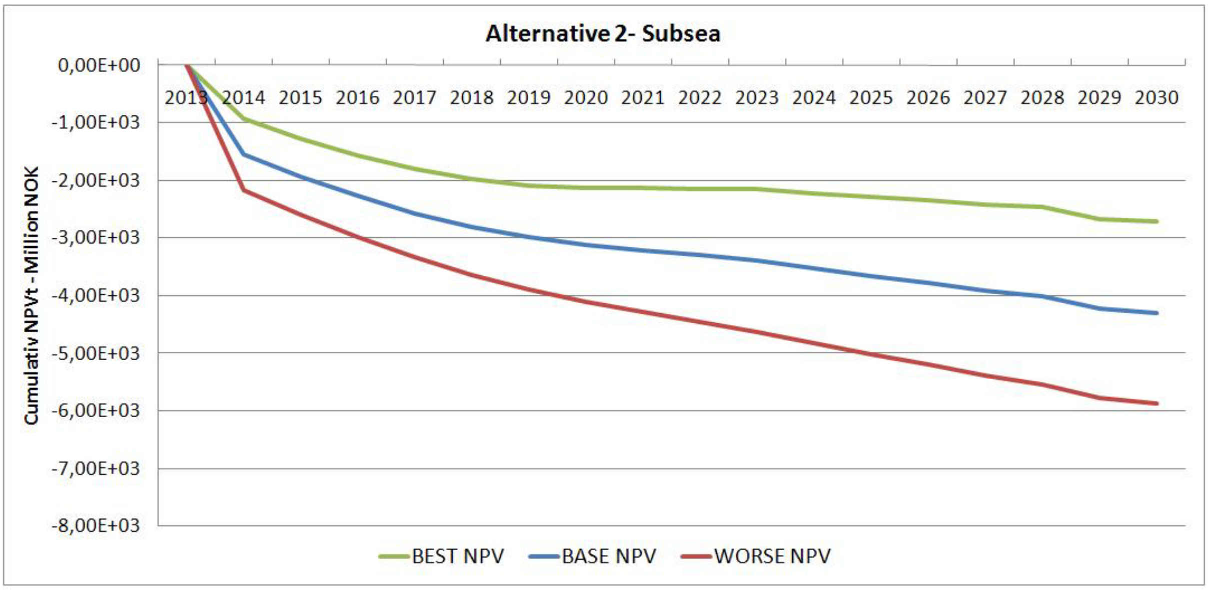

Figure 63: Alternative 2 - Part B - Cumulative NPV

The Alternative 2B is most sensitive to the oil and gas price. As the relation in percentage between the NPV and the oil and gas price is nearly 1. A change of 30 % of the opex costs would lead to a change of 10 % of the NPV, this is a slightly lower influence than the one of the capex (Figure 64).

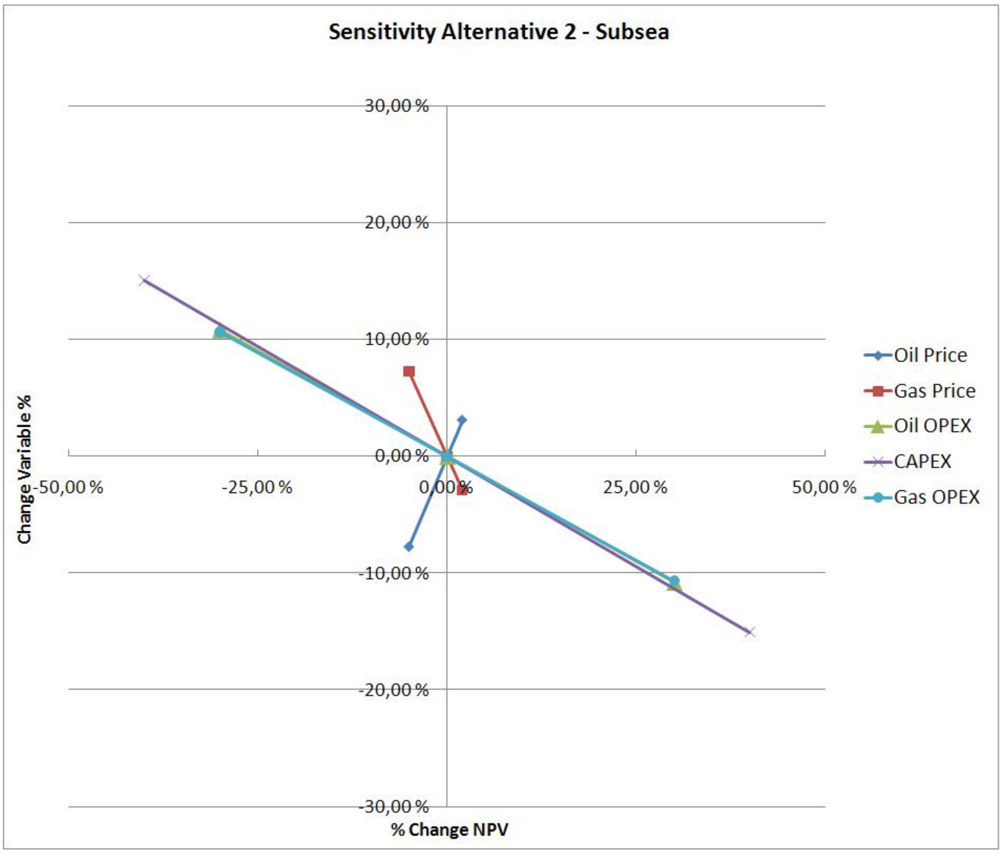

Figure 64: Alternative 2 - Part B - Sensitivity

Comparison and recommendation Part B

As both of the Alternatives in Part B show negative revenue, none of them should be done with the actual settings. The main factor for the bad economic results is the injected gas, as the assumption is “if more gas is injected than produced it has to be bought for the assumed gas price”, it cost a high amount and takes a lot of the revenue which is won through the oil.

5 Conclusion

When comparing the five-branched smart well with the extended case different aspects can be seen. From the technical point of view the smart well seems to be a better solution in the long run. The five-branched smart well produces with a much more stable oil production rate than the extended case; which leads to a lower production rate at the start of production but a higher one after 2020. The field oil production total of the extended case is higher until the year 2030, after that the five-branched smart well has a higher total oil production. From an economic point of view the extended case is the better solution in this specific case. The extended case shows positive revenue in the Best- and Base Case, whereas the five-branched smart well shows negative revenue in all cases. Based on our assumptions Statoil should not implement Smart Wells. The ICD case did not provide any clear result and therefore no recommendation can be given.

Figures

Tables

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