IMPROVED OIL RECOVERY

GULLFAKS SØR STATFJORD

EXPERTS IN TEAM

TPG-4851 GULLFAKS VILLAGE

GROUP – 6

NTNU – TRONDHEIM

2010

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Project Overview

The Gullfaks field is situated in 34/10 in the northern part of the North Sea. It is in the Tampen area and has oil and gas reservoirs in the Brent group, Cook, Statfjord and Lunde formations. The Gullfaks field consists of the main field and six satellites. Gullfaks Sør is the largest of the satellites and our task is to propose measures that can increase the oil recovery from this field. In Part A of the task we have simulated a reference case provided by Statoil and an extended case where we have included four new oil producers and two new gas injectors. This report demonstrates our understanding of the challenges related to increased oil recovery and our evaluation of the economic aspects of the different alternatives for the new wells.

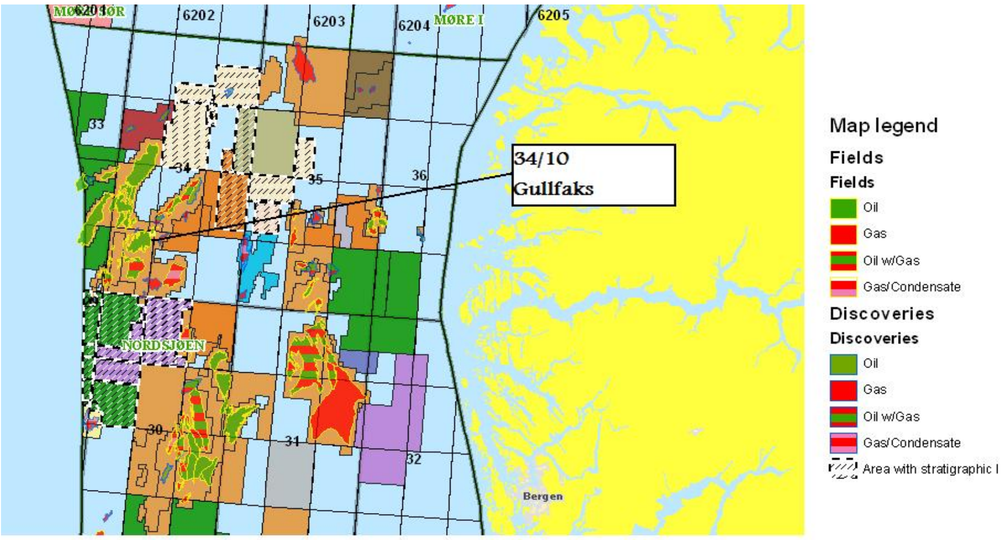


Figure 1 The Gullfaks Field in the North Sea

Gullfaks Sør In Glance

Formation

The Gullfaks Sør satellite field is a rotated fault block, dipping towards west on the south of Tampen Spur. The structure is a result of two rift phases, Permo - Triassic and late Jurassic - early Cretaceous. The structural development of the first phase had a large impact on how the second rift phase developed. Gullfaks Sør has a low recovery factor, which is due to heavily segmented sealed faults, complicated fluid contacts and flow patterns. There has been performed a study which found a number of deformation bands linked to faults and that was interpreted as the most important reason for reduced communication.

The Gullfaks Sør contains large volumes of oil in both the Brent group and the Statfjord formation. The Gullfaks Sør Statfjord formation is the aim of our increased oil recovery task. The Gullfaks Sør Brent group consists of several segments that have bad pressure communication, but has been producing both oil and gas and is the main supplier for gas injection to the other satellite fields. Because of high depletion in the Brent group the increased oil recovery in the Statfjord formation has to be planned without drilling through the Brent group.

The reservoir in the complex Statfjord formation has been shut-in since October 2008 to increase drill ability and pressure. There are six producers where two are smart branch drillers (G-2YH and F-2YH) and one smart well (G-1H) and one gas injector. The plan was to reopen the reservoir when injector E-1 was fixed and a new injector E-3 installed. The field is still shut-in.

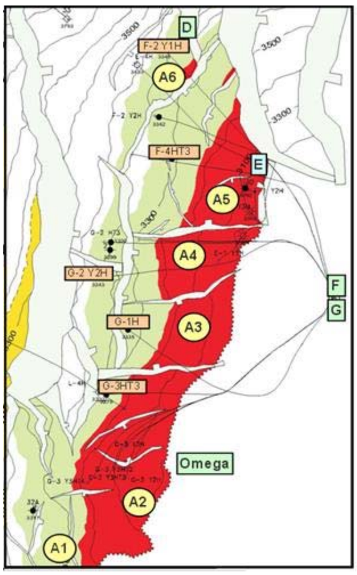


Figure 2 Gullfaks Sør Statfjord formation (Top View)

The general paleoenvironment in the Statfjord formation is that of alluvial plain deposits cut by northwards flowing axial rivers with local, lateral fans along the margins.

The Statfjord formation is subdivided into three members, Nansen, Eiriksson and Raude. Nansen and Eiriksson members consist of massive, fairly homogeneous and highly permeable (0.5-2D) sands with shales and coal horizons. The shales are assumed to be laterally continuous, especially in Nansen formation.

Erikssson-1 unit and the Raude member in the lower part of the Statfjord formation are distinguished by frequently alternating Shales and sands of varying thickness and reservoir quality.

The upper Statfjord formation is approximately 70-80 m thick while the lower Statfjord formation has a thickness of 160-175 m. It has been observed from the wells and observation boreholes that layers are interconnected with each other in Statfjord formation.

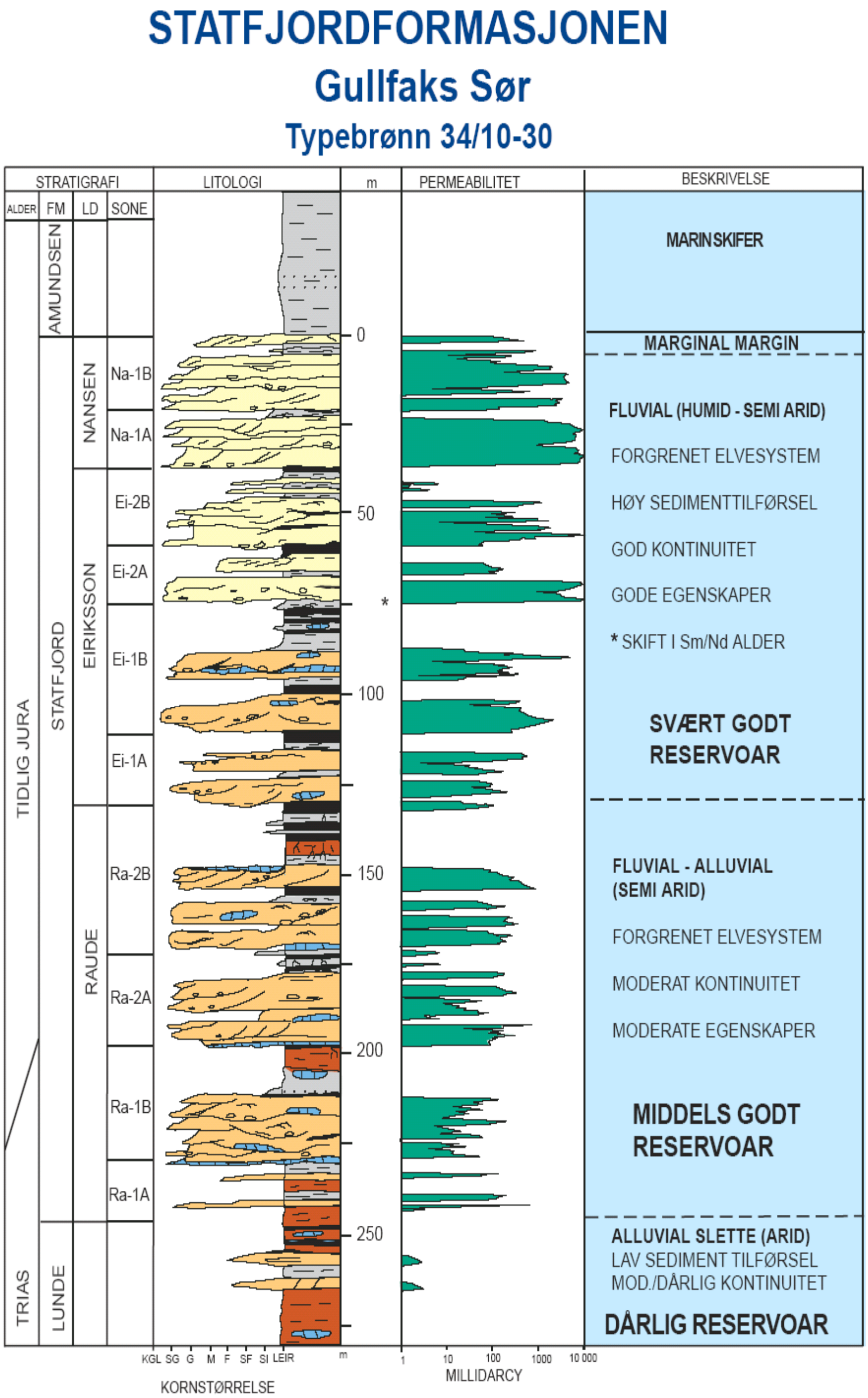


Figure 3 Gullfaks Sør Statfjord formation (Cross Section)

Reservoir Management

The Gullfaks main field is mostly producing oil whereas the Gullfaks Satellite fields contain more gas than oil with a significant gas cap. The Gullfaks Sør reservoirs are significantly deeper and the properties (porosity & permeability) are much less favorable. Due to higher overburden, the porosity and permeability are lower than at the Gullfaks main field.

The main recovery strategy for the Gullfaks satellites is gas injection for pressure support and to replace the produced reservoir volume. Gullfaks Sør has a constraint of handling gas volumes at platform A, so the emphasize is to keep the GOR in the wells as low as possible.

The Gullfaks Sør management mainly focuses on oil production, but there has also been a plan to blow down the gas cap in the Statfjord reservoir.

Gullfaks Sør (Statfjord Formation) main data is as under:

Top Structure	3000 m MSL
Datum	3300 m MSL
Porosity	20 %
Oil-Water Contact	3362 m MSL
Gas-Oil Contact	3224 m MSL
Oil Column	138 m
Water depth	130 m
Initial Pressure	476 bar
Initial temperature@ 3300	128 C
Gas gradient (bar/m)	0.0291
Oil gradient (bar/m)	0.0693
Water gradient (bar/m)	0.103
Temperature gradient	0.032

Resources & Reserves:

The development of resources and reserves over time has not been as favorable on the Gullfaks satellites as on the Gullfaks main field.

The total reserves and recoverable resources in the Gullfaks Sør field are as under:

	Oil/Condensate	**Gas**
Originally in place	42.22	19.03
Currently in place (2015)	36.69	18.15

Part A Reservoir simulation

A. Background

The focus of this study is on the Gullfaks Sør field. The Gullfaks Sør started its production in 1999, and the oil recovery has been very low, around 10%. It is required to do comprehensive study in the effort to increase the oil recovery of the field.

This section mainly focuses on the understanding of a reservoir model that has been developed for Gullfaks Sør and verifies that the plan, established by Statoil, is economically viable and increases the oil recovery factor of the area quite significantly.

There are two main reservoir simulations that have to be done:

- Reference case, which is a do nothing case. The production in this case is just as per existing configuration: no additional wells, and no additional surface facilities infrastructures. The main purpose for this model is to match the production history with the reservoir simulation model.
- Extended case, which is the case with the introduction of new production wells, injection wells and additional infrastructures (subsea facilities or platform). The case is planned to be started on October 1st 2015 and will last up till the beginning of 2030. This case is divided into two sub cases: reservoir simulation with the two new injection wells and without injection wells, for which the idea is to check the economic value of adding new injection wells.

B. Basic Assumptions

General assumptions of the model:

- History match is done by mainly matching / inputting the oil production rate
- The field started its production in early 1999
- The extended case modification project is started from October 1st 2015
- The field production will end at the beginning of 2030
- Gas production rate from each well is limited to 1 MM SM3/day due to gas processing capacity limitation on the surface.
- Production rate / cumulative is assumed to be the same for additional platform or additional subsea facilities, no production increment due to back pressure reduction.

Economics assumptions:

- The economic calculation is based on **increment** to reference case / do nothing case
- The extended case with no injection, is economically analyzed with base case data only
- Exchange rate is assumed to be constant 1 USD = 6.28 NOK
- Base case for discount rate is 7%
- Net Present Value (NPV) is calculated to the year of 2010
- Oil price is forecasted to be around USD 110 / barrel on 2016 and increase at constant level 3% every year afterwards

- Gas price is forecasted to be around USD 10 / MMBTU on around 2016, and increase at constant level of 3% every year afterwards. Gas heating value is assumed to follow 1 Mscf = 1 MMBTU
- Capital Expenditures (CAPEX) assumptions:
  - One Additional drilling platform costs 1750 MNOK
  - One Additional subsea facility (manifolds + control system) cost 1000 MNOK
  - Drilling one well from platform costs 100 MNOK
  - Drilling one subsea well costs 125 MNOK
  - Cost phasing for surface facilities is distributed in 5 years with configuration: 10% - 20% - 30% - 25% - 15%
  - Cost phasing for drilling is distributed in 4 years equally
  - Abandonment cost for 1 platform well is cost 25 MNOK
  - Abandonment cost for 1 subsea well is cost 32.5 MNOK
- Operational Expenditures (OPEX) assumptions:
  - Annual increment operating cost for additional drilling platform is 75 MNOK, and increase 3% per year
  - Annual increment operating cost for additional subsea facilities is 50 MNOK, and increase 3% per year
- Sensitivity analysis (to cover uncertainties)
  - Oil recovery +/- 25%
  - Gas recovery +/- 25%
  - Oil price +/- 40%
  - Gas price +/- 30%
  - CAPEX +/- 10%
  - OPEX +/- 15%
  - Discount rate +20% -10%

C. Simulation Result

No.	Description	Reference Case	Extended Case (Base Case)			
			With Injection		No Injection	
1.	Oil recovery cumulative, MM SM3 (RF, %)	8.87 (21.02)	13.45 (31.86)		11.05 (26.19)	
2.	Gas recovery cumulative, MM SM3 (net)*	9501.48	13391.68		12356.88	
3.	Peak oil production, SM3/day	2800	4000		4000	
4.	Peak gas production, MM SM3/day	2	5.5		2.9	
5.	Peak water production, SM3/day	1360	1440		1960	
6.	Economics		Platform	Subsea	Platform	Subsea
7.	Increment Net Present Value (NPV)	--	146.63	768.75	-443.79	98.44

	- MNOK					
8.	Internal Rate of Return (IRR)	--	9.16%	21.39%	--	21.23%

* Production minus injection

- On the ‘extended case with no gas injection’, the production will stop on early 2023, while the other cases, the production will continue until end of 2029.
- The new producing wells (‘extended case’) are contributing almost the same cumulative oil production, which is around 1.28 MM SM3, which give economically balanced, that each wells has almost the same economic value.
- Since the production rate for the extended case is higher than reference case and all the flow are gathered in a common processing platform, further facilities study on checking the facilities capacity limitation (such as: oil and water handling capacity, gas processing capacity, pipeline capacity, etc) is required.
- The extended case with gas injection has the best economic value, which also gives the highest oil recovery factor. The extended case with no gas injection wells has almost the same IRR with adding injection wells, even though the extended case with gas injection wells has higher NPV, due to higher CAPEX and OPEX too.

Gullfaks Sør reservoir 3D-view

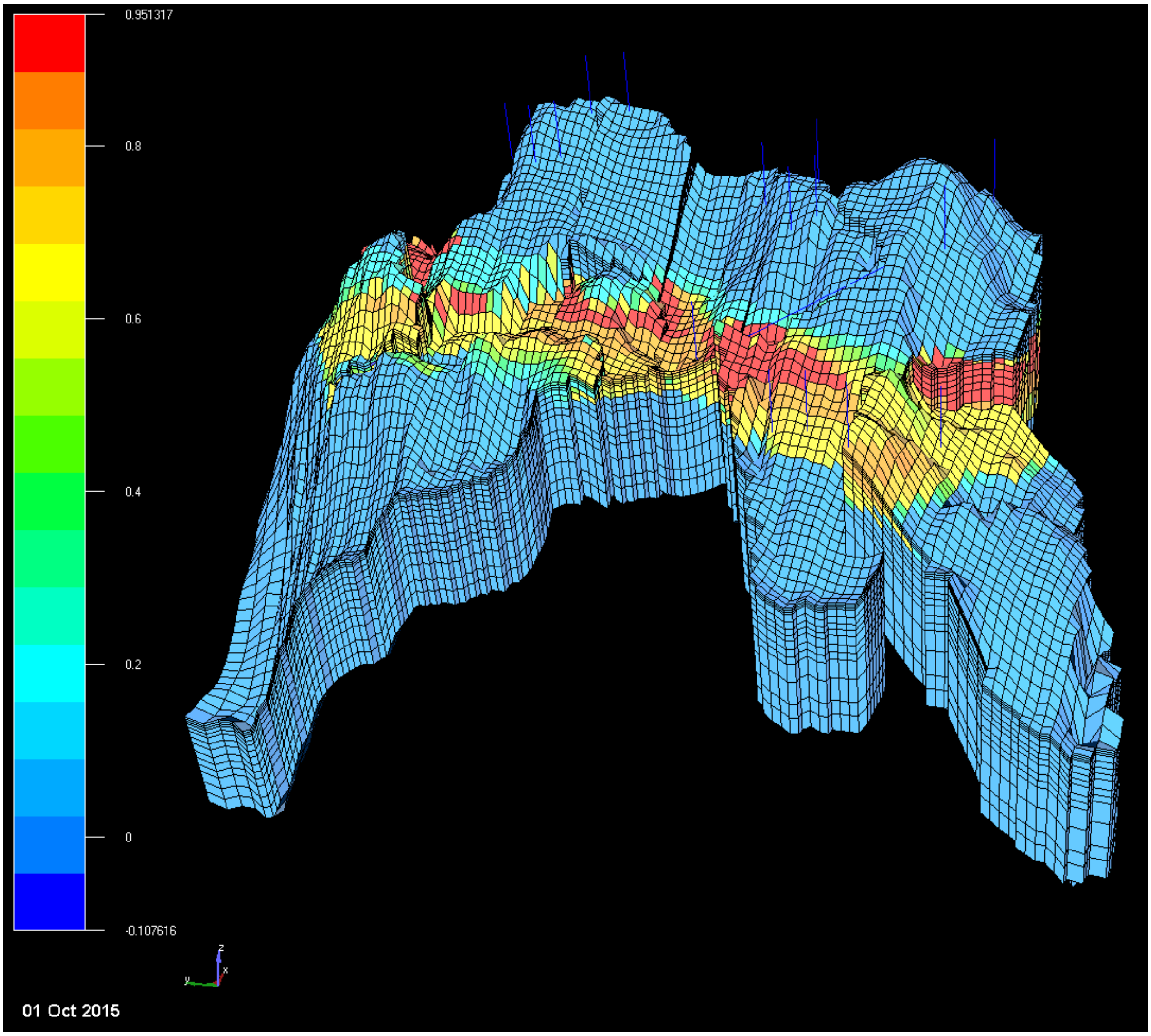


Figure 4: SOIL 01 October 2015 Reference case/ Extended case

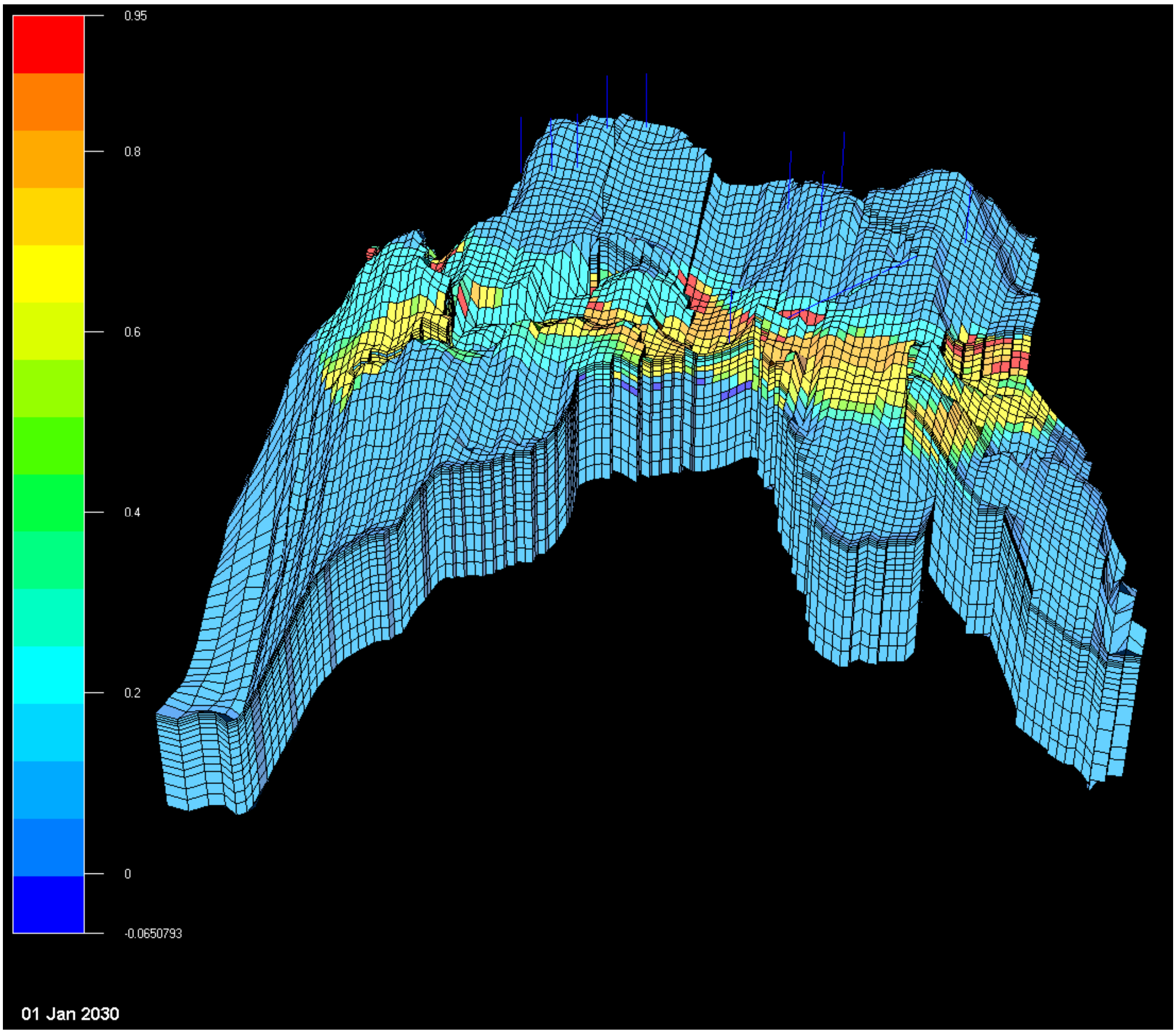


Figure 5: SOIL 01 January 2030 Reference case

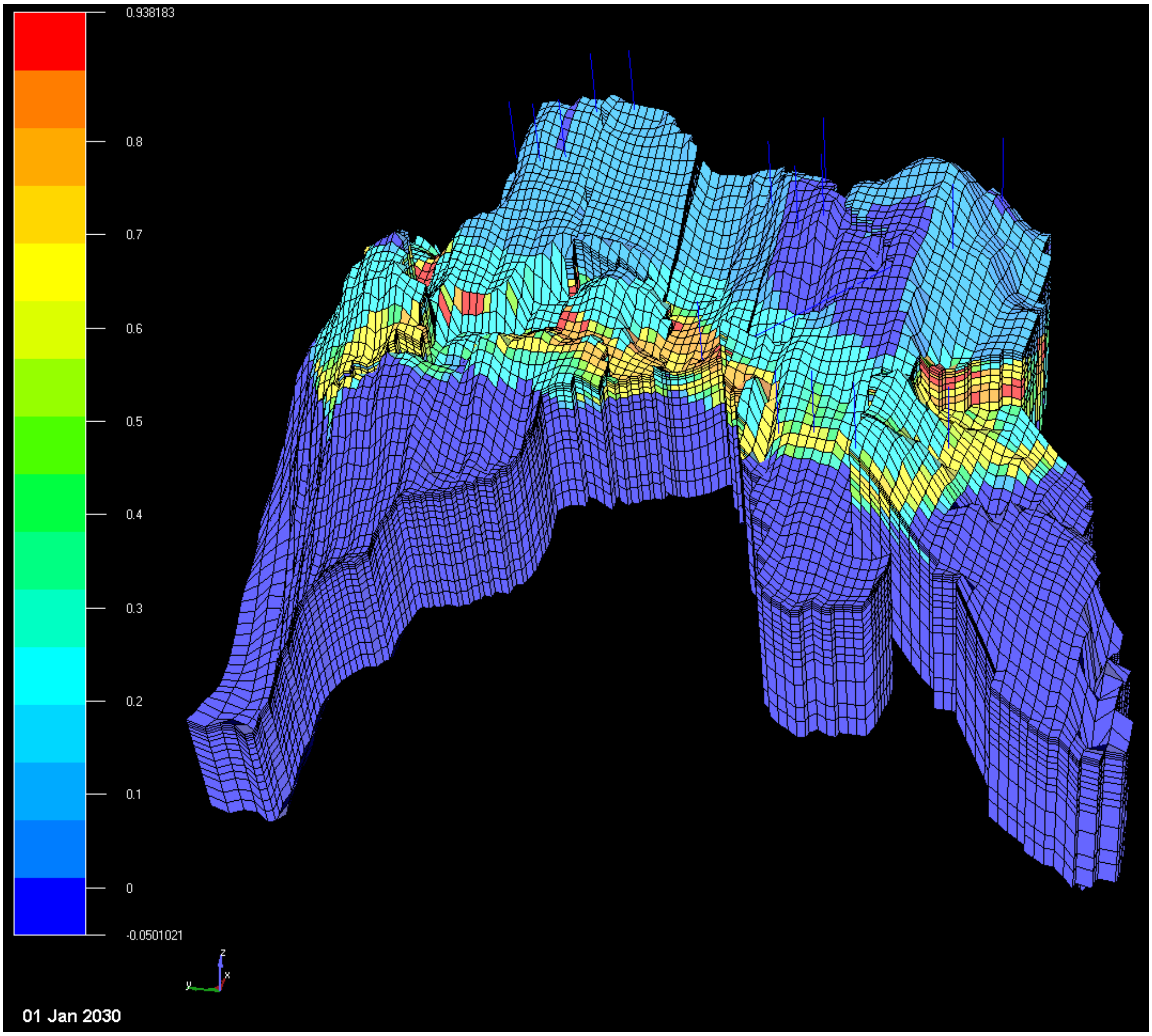


Figure 6: SOIL 01 January 2030 Extended case

- Figure 4 illustrates how the reservoir is simulated to be in 2015, the SOIL is the same for the Reference case and the Extended case because the new wells in the Extended case are not put in production before this date.
- Figure 5 illustrates how the reservoir would be depleted with the existing wells from the Reference case in 2030. We can see that there is still a lot of oil in large compartments, about 70% oil saturation. This shows that in order to get a higher recovery factor, a new recovery pattern should be designed.
- Figure 6 illustrates how the reservoir would be depleted after adding the new producers and injectors in 2030. This shows a satisfying result with a 10% higher oil recovery than from the Reference case. There are still some small pockets that contain about as much as 80% oil. These are isolated compared to the large compartments still containing oil in figure 5. The small isolated pockets might be a result of the sealing faults, and this shows that the Extended case wells are not optimal for the complex reservoir. Other methods should still be designed.

Conclusion

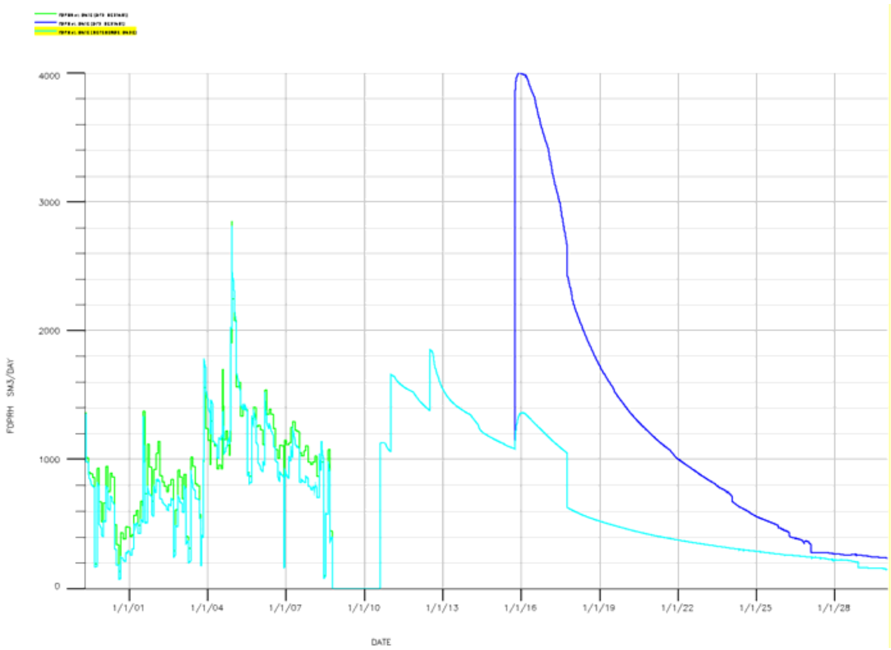
- The extended case with gas injection and additional subsea facilities has the best economic impact for the field, and fulfill Statoil's target to increase the recovery factor of the field by around 10%. (see *Appendix D*, for detail decision tree for the Improved Oil Recovery study)
- The NPV of the extended case with injection is 765.75 MNOK for subsea case and 146.63 MNOK for platform case, where the big difference is mainly caused by the higher Capital and Operational Expenditures for having a platform. And it is assumed that a platform and subsea facility will give the same recovery factor, even though there will be some increment due to back pressure reduction by installing a platform instead of subsea facilities, which is not part of this study.
- Sensitivity analysis gives an indication that the oil price and oil recovery are the most sensitive parameters to the project NPV. And OPEX is the parameter that is the least sensitive to the field NPV increment.

References:

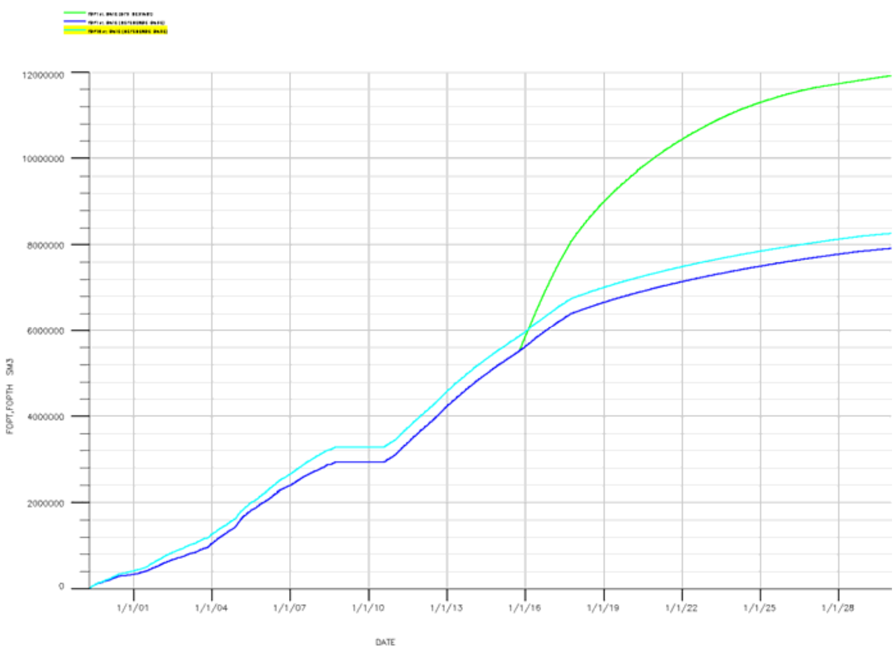
1. Reservoir Management Plan for Gullfaks. November 2007
2. Årlig statusrapport 2008 for Gullfaks. Oktober 2008
3. Power Point presentation: The economical assumptions, Gullfakslandsbyen 2009
4. Eclipse technical manual
5. Eclipse output file GFS_RESTART.PRT

Appendix A: Gullfaks Sør Field Charts

Field Oil Production Rate (FOPR)



Field Oil Production Total (FOPT)

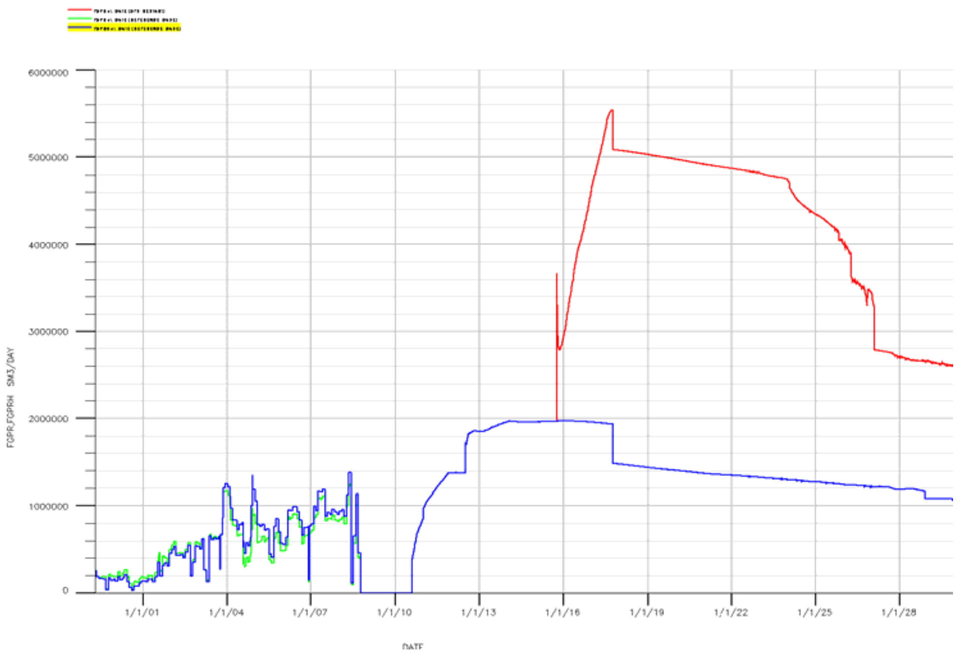


- The extended case gives additional oil production (around 4.5 M SM3)

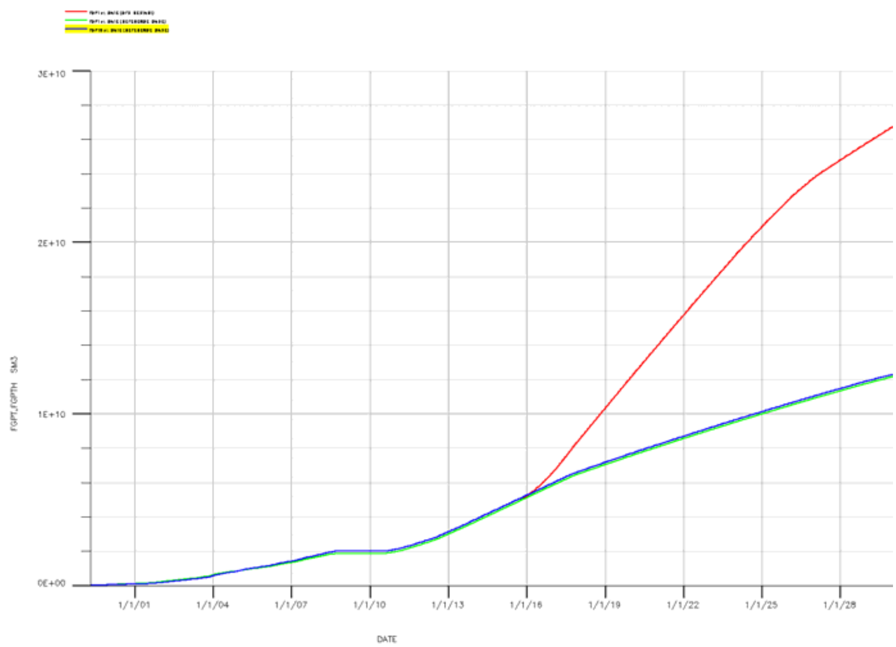
- The oil plateau rate is around 4000 SM3/day which last for around 1 year (from Oct 2015 to Oct 2016)
- Well W2W3 is the highest oil producer compare to other new producing wells
- The old wells cumulative oil production is decreased in an average of 25%, with the additional new producing wells (extended case). The most affected old well is G-2ML, with reduction up to 28%.
- The field oil recovery factor is increased by 52 %, in which the reference case gives recovery factor 21.02% and the extended case gives recovery factor 31.86%
- The extended case with gas injection gives additional NPV 146.63 MNOK (platform) and 768.75 MNOK (subsea template)

* The oil production history is quite matched with the simulation model
* The cumulative oil production for the extended case is quite higher than the reference case. The increase in production is around 4M M3.

Field Gas Production Rate (FGPR)



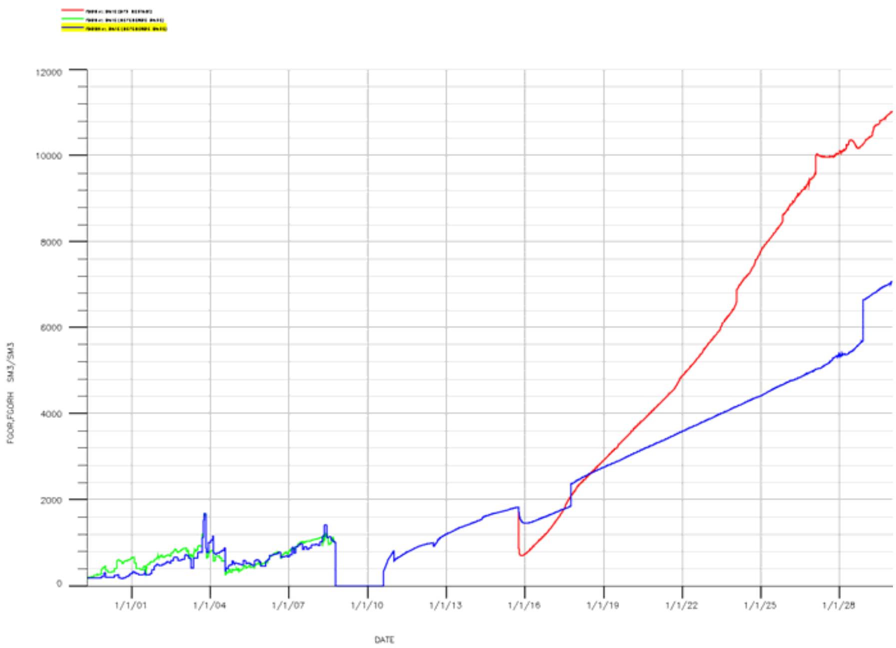
Field Gas Production Total (FGPT)



- The gas production rate for extended case is increasing compared to reference case. This may be due to increased gas injection causing the GOC to move down and ultimately gas production increases. The difference is almost + 3 M Sm3/day.

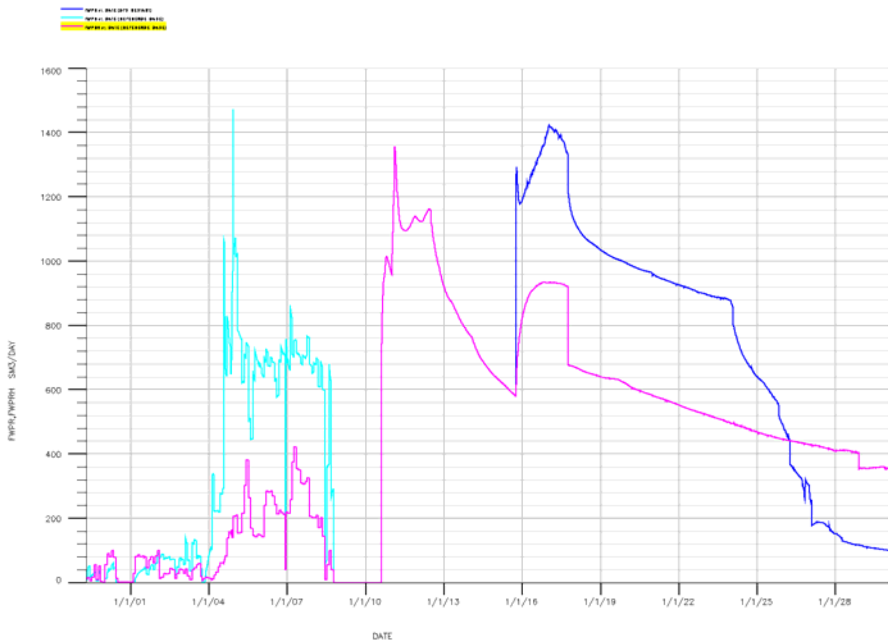
- The cumulative gas production for the extended case is quite higher than the reference case. The increase in production is around 14.2 Billion M3.
- The cumulative gas injection for the extended case is 15 Billion M3, whereas for the reference case is 4 Billion M3.

Field Gas Oil Ratio (FGOR)

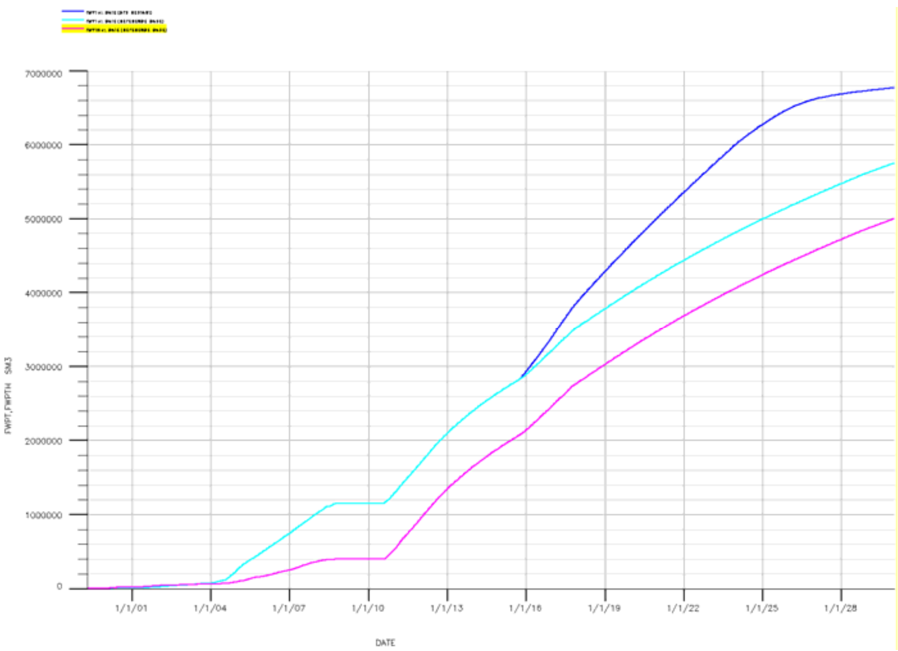


- FGOR of the extended case is decreasing in early phase of production (4 months), probably because of increase oil production rate.
- FGOR for the extended case is higher / increasing quickly due to:
    - o Possibility of reservoir pressure reaching below bubble point pressure faster for the extended case, because of increase oil production
    - o Due to gas injection, gas oil contact level is moving down, which may increase the overall field gas production
    - o Due to increase oil production, the associated gas is also increased
- The actual FGOR is quite matched with the simulation model

Field Water Production Rate (FWPR)

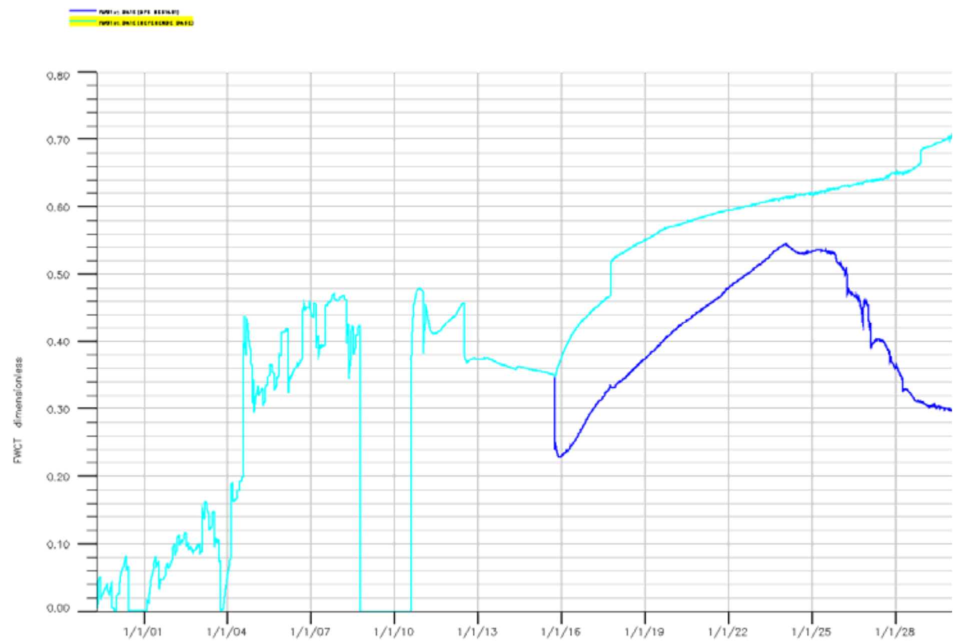


Field Water Production Total (FWPT)



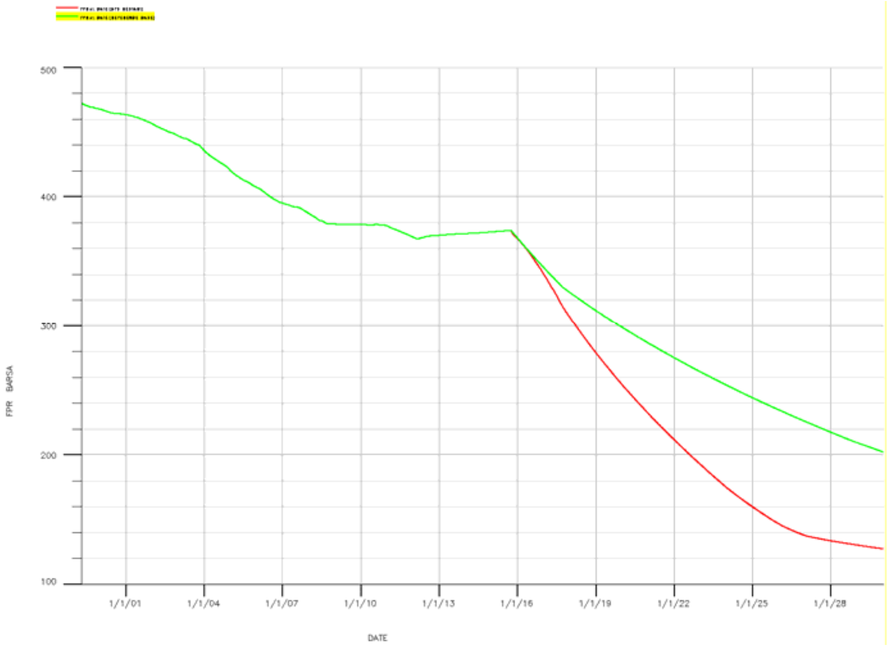
- The cumulative water production for the extended case is higher than the reference case. The increase in production is around 1.0 M M3.
- The simulation and history are not matching from 2004 and onward, also simulation model shows history beyond 2010 which is not

Field Water Cut (Extended Case Vs Reference Case)



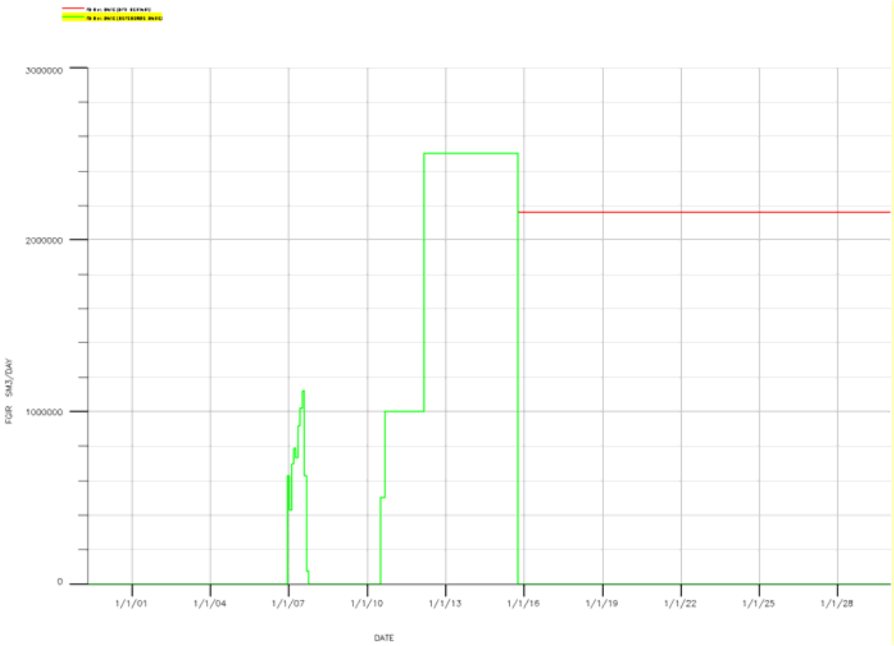
- The extended case gives maximum water production up to around 1420 SM3/day, which is below the history of the maximum water production, 1449 SM3/day. It means no constraint on water handling capacity in the platform.
- The reservoir pressure is being maintained by gas injection, which slowing down the oil water level to move up.
- The water cut / water production rate is decreased in the later stage of production, due to shut in of some highly water producing wells

Field Pressure (FPR)

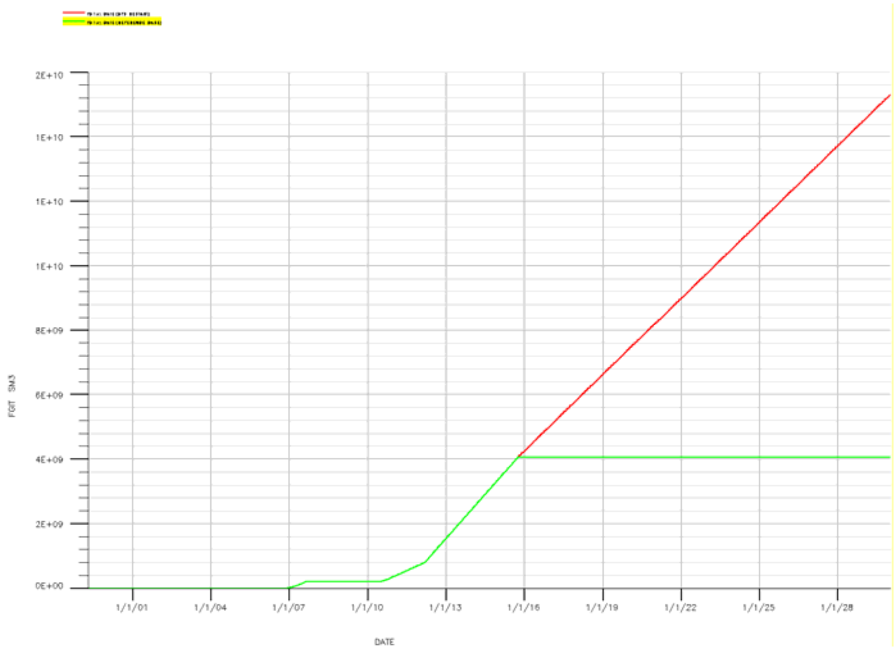


- Pressure for the extended case is decreased faster than the reference case, due to high reservoir drainage compare to gas injection rate. May be we can get higher recovery, if we increase the gas injection rate (depending upon the constraint on the gas processing capacity in the platform, which is used as production control strategy for the new wells)

Field Gas Injection Rate (FGIR)



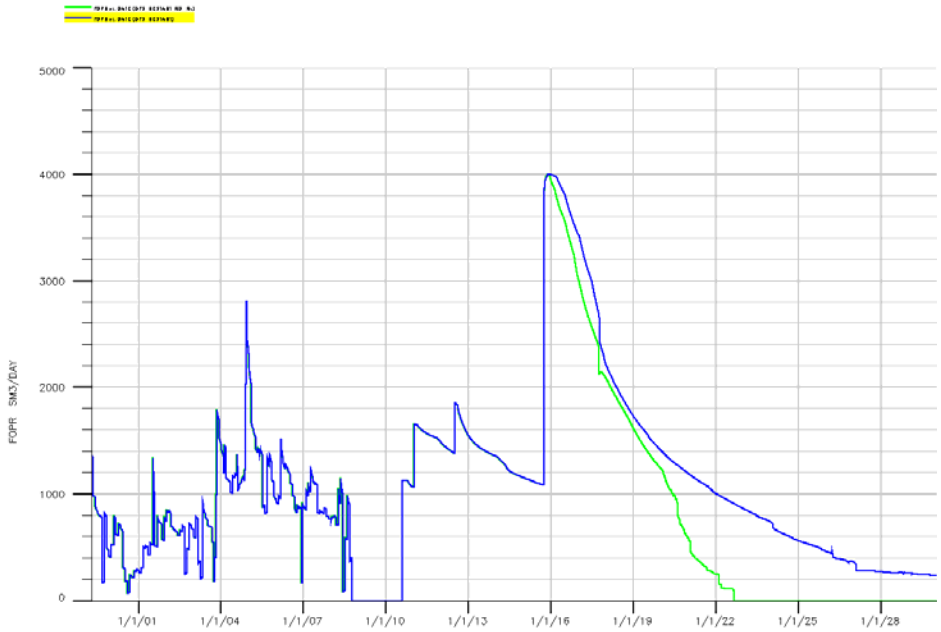
Field Gas Injection Total (FGIT)



- The cumulative gas injection for the extended case is quite higher than the reference case. The increase in injection is around 11.0 Billion M3.
- The cumulative gas injection for the extended case is 15 Billion M3, whereas for the reference case is 4 Billion M3.

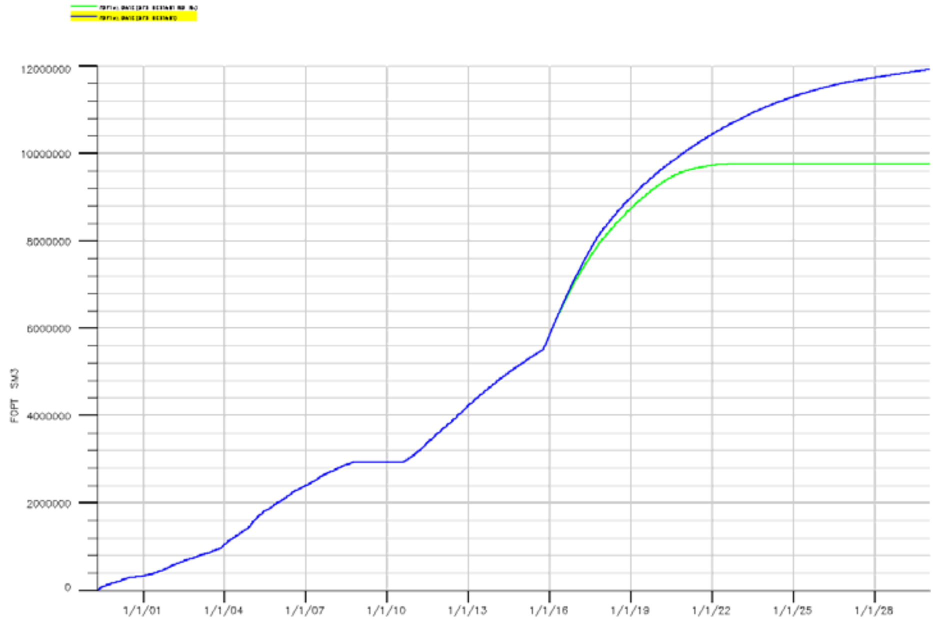
Field Graphs with no injection

FOPR-no gas injection



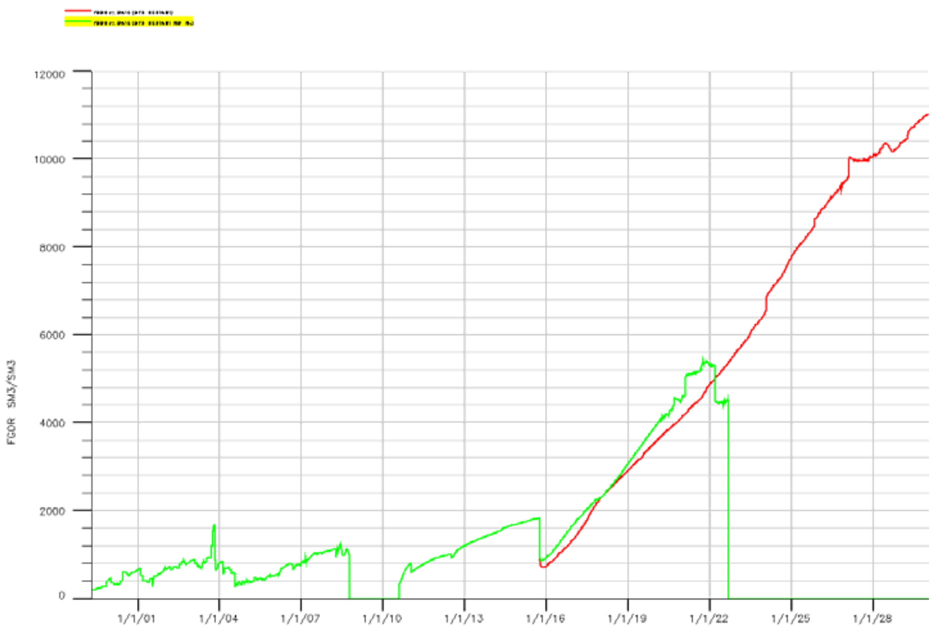
- Less recovery for no injection
- Stop production at 2023

FOPT-no gas injection

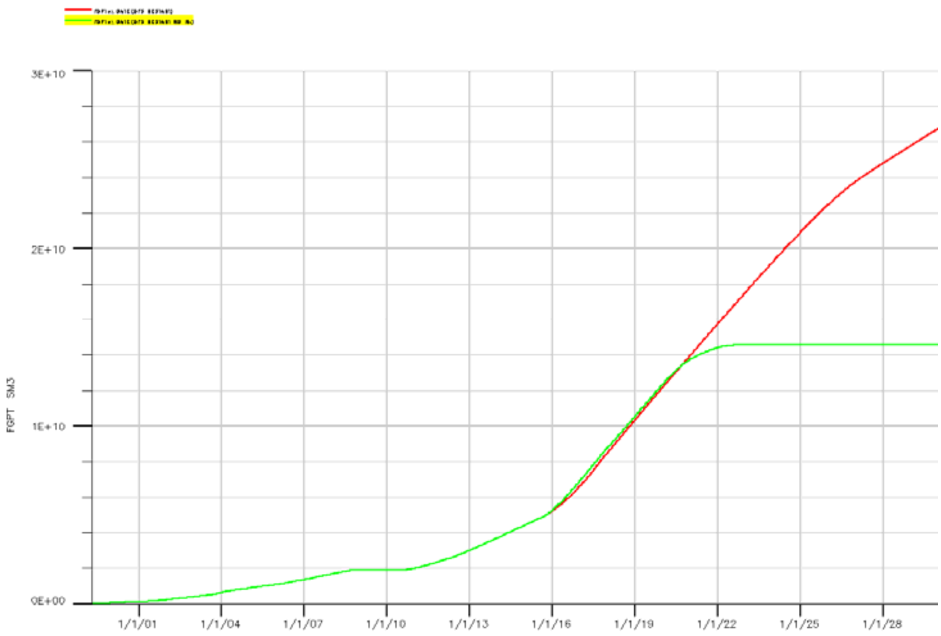


- The cumulative oil production difference is around 2.2 M SM3

FGOR--no gas injection



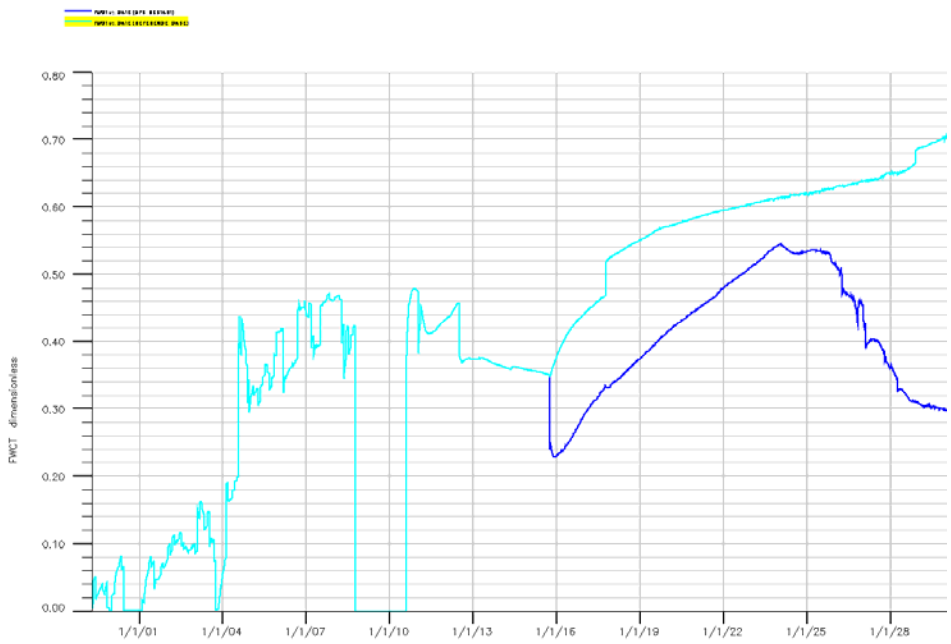
FGPT--no gas injection



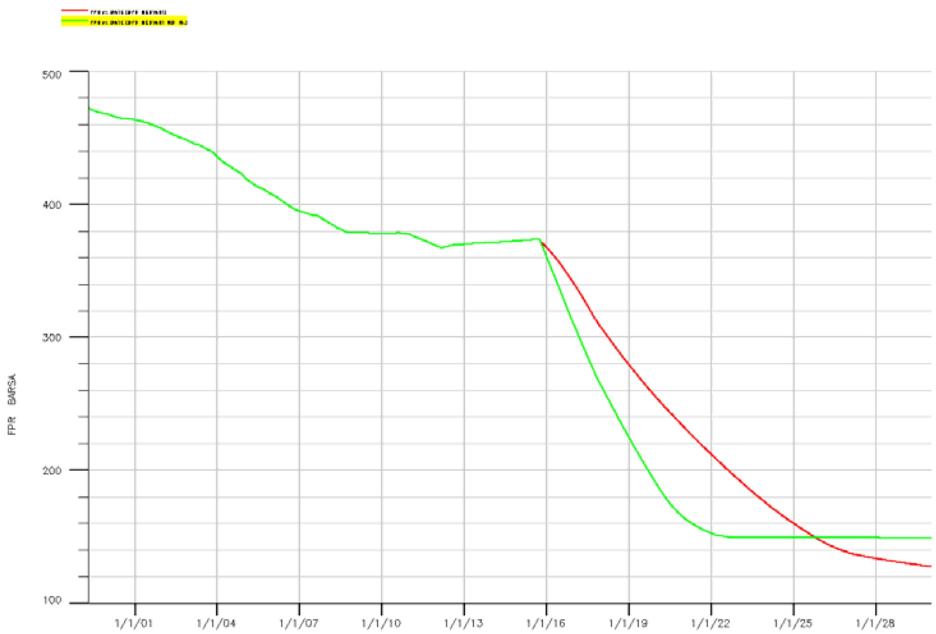
FWPR-no gas injection

- The oil water contact for non injection case is rising up faster, which cause increase water production

FWCT-no gas injection (Ref vs Extended)



FPR--no gas injection

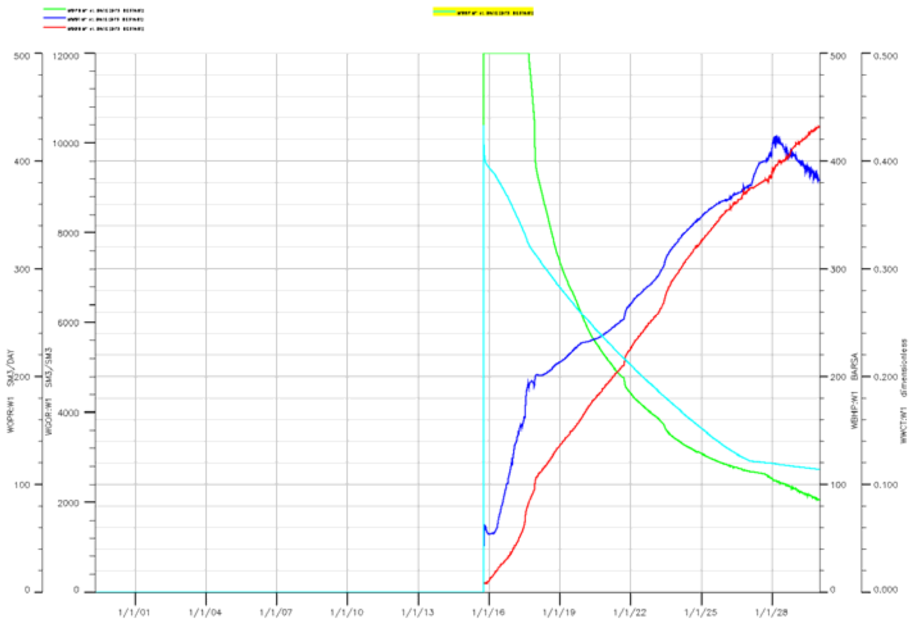


- The reservoir pressure is declining faster with no injection case
- The abandonment pressure is lower for injection case, which gives higher recovery factor

Appendix B: Well by Well Charts

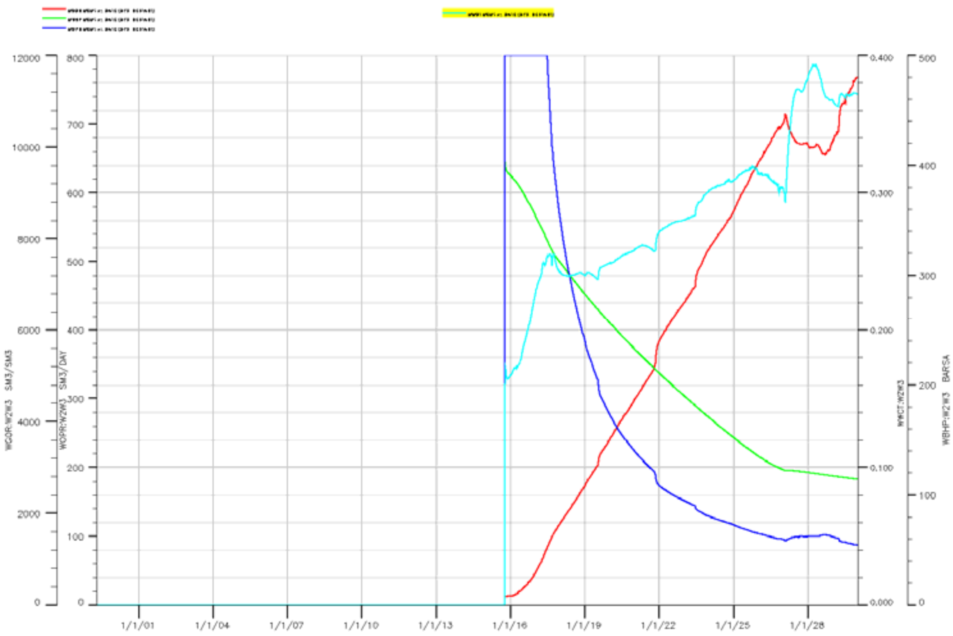
New Proposed Wells

Well W1



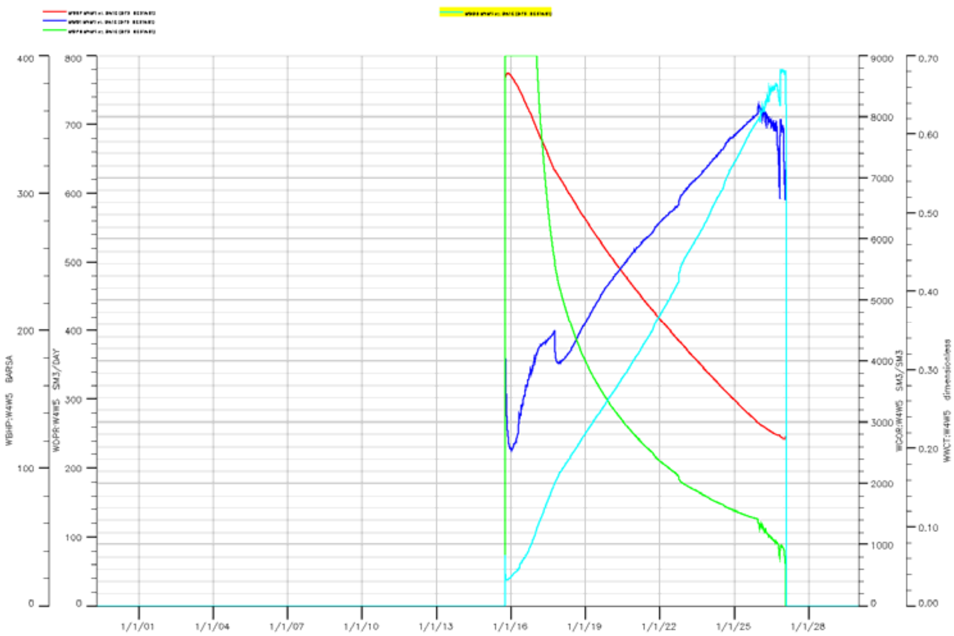
- Well W1 is producing around 1.16 million M3
- Oil plateau rate is last for around 23 months, which is 500 SM3/day
- GOR and water cut are continuously increasing during it’s life
- Bottom hole pressure is continuously decreasing down to 85 Bara

Well W2W3



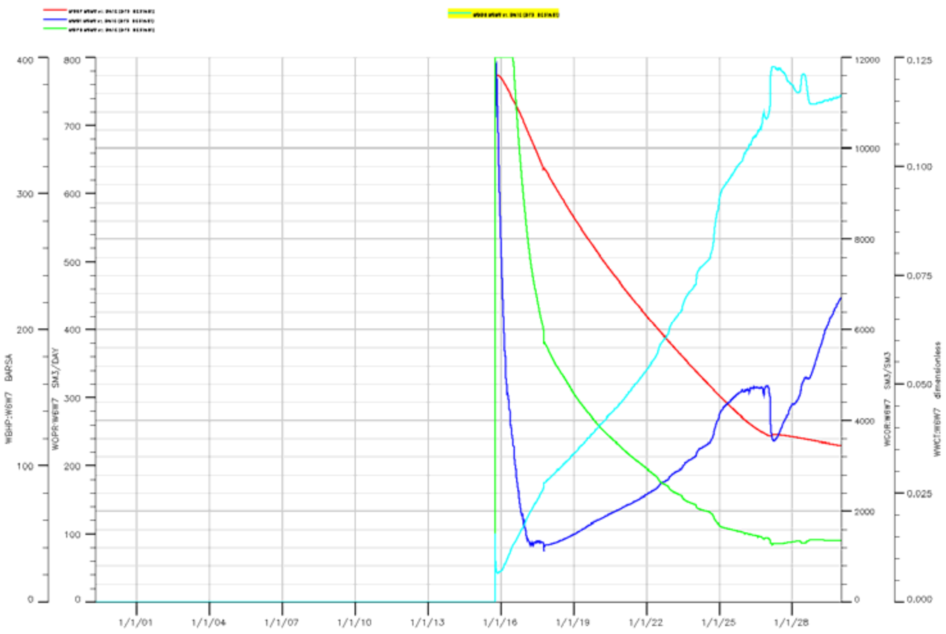
- Well W2W3 is producing around 1.42 million M3
- Oil plateau rate is last for around 21 months, which is 800 SM3/day
- GOR and water cut are continuously increasing during it's life. The water cut profile is a bit fluctuating, which could be because of the complexity of the reservoir and is producing from more than 1 zone (Multi-Lateral Well)
- Bottom hole pressure is continuously decreasing down to 115 Bara

Well W4W5



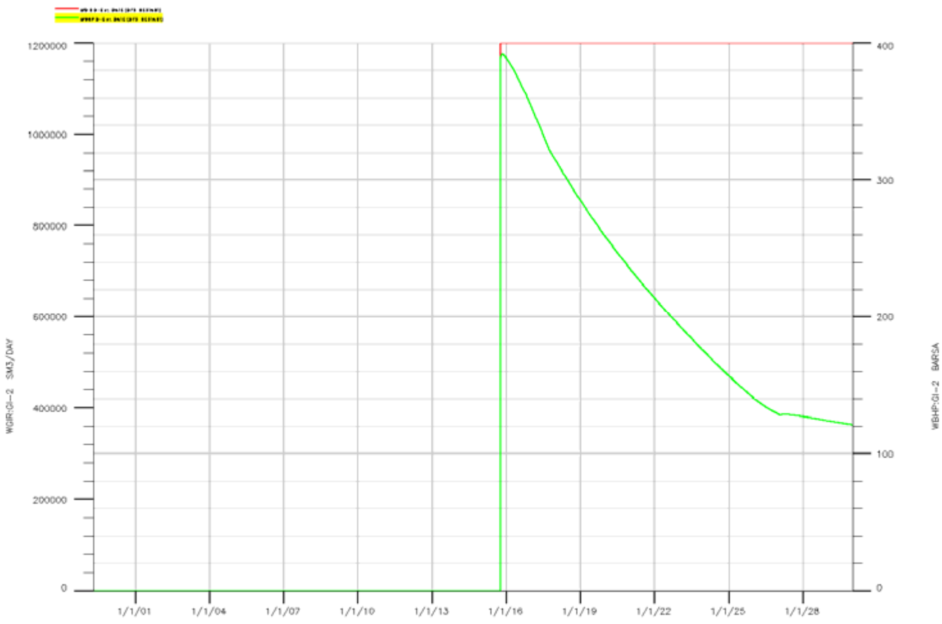
- Well W4W5 is producing around 1.30 million M3
- Oil plateau rate is last for around 16 months, which is 800 SM3/day.
- The oil production is ceased on around early 2027, which is controlled by the maximum allowed gas production rate (1 million SM3), and could be due to high water production rate in relation with bottom hole pressure.
- GOR and water cut are continuously increasing during it’s life. The water cut profile is a bit fluctuating, which could be because of the complexity of the reservoir and is producing from more than 1 zone (Multi-Lateral Well)
- Bottom hole pressure is continuously decreasing down to 120 Bara

Well W6W7



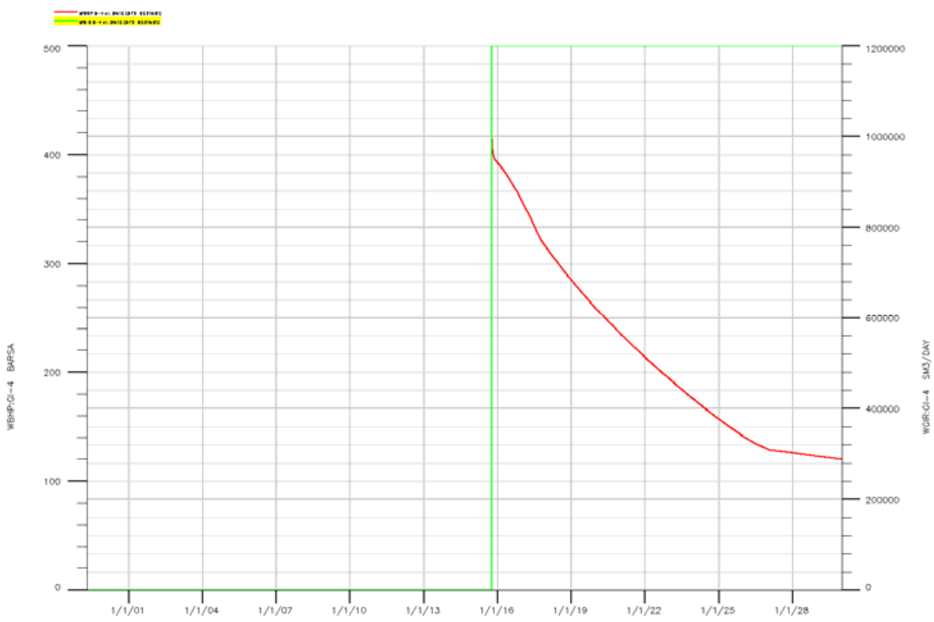
- Well W6W7 is producing around 1.24 million M3
- Oil plateau rate is last for around 9 months, which is 800 SM3/day.
- GOR and water cut are continuously increasing during it's life. The water cut profile is a bit fluctuating, which could be because of the complexity of the reservoir and is producing from more than 1 zone (Multi-Lateral Well)
- Bottom hole pressure is continuously decreasing down to 115 Bara

Well GI-2



- Maintain the constant injection rate of 1.2 M SM3/day

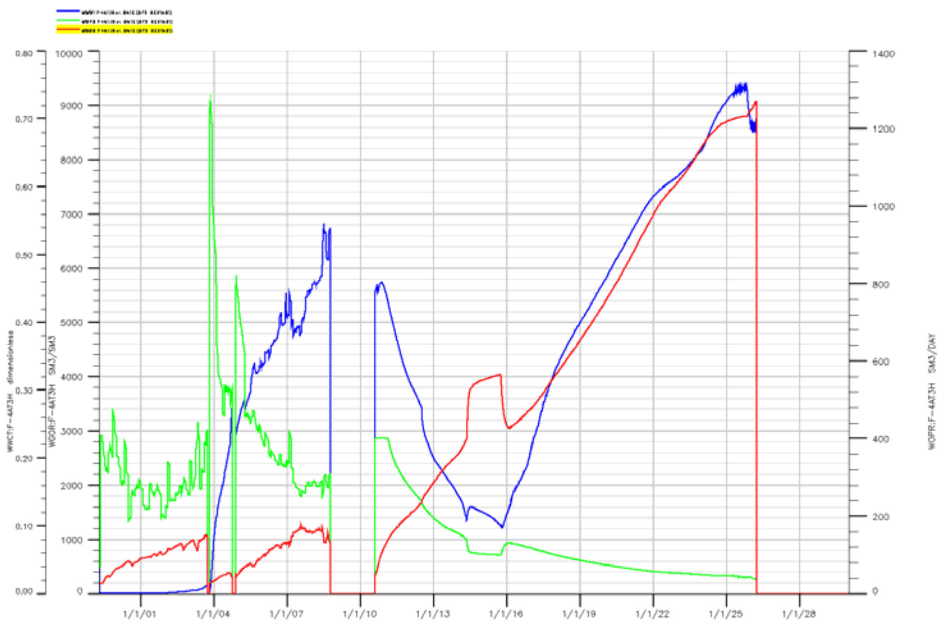
Well GI-4



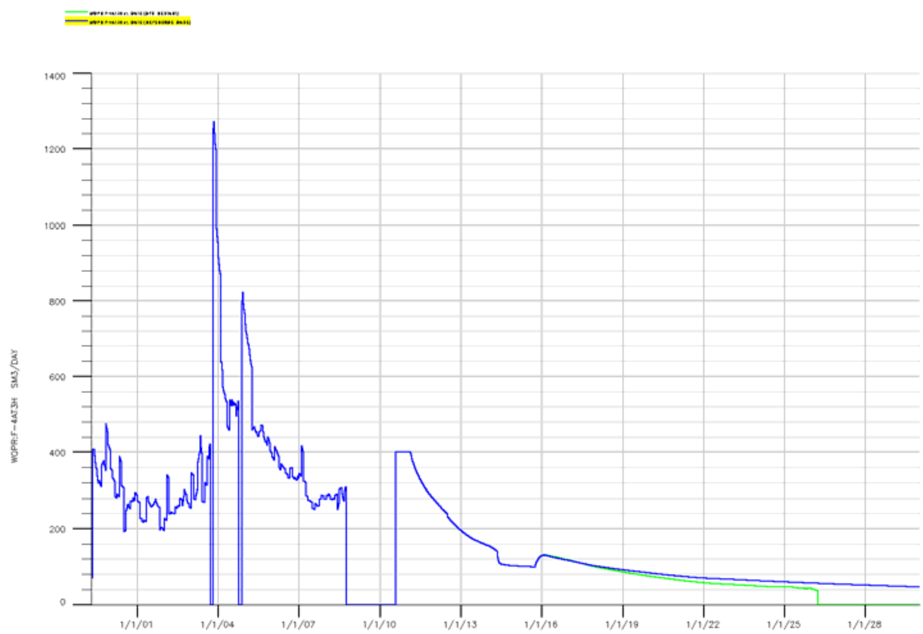
- Maintain the constant injection rate of 1.2 M SM3/day

The Existing Wells

F-4AT3H (Extended Case)

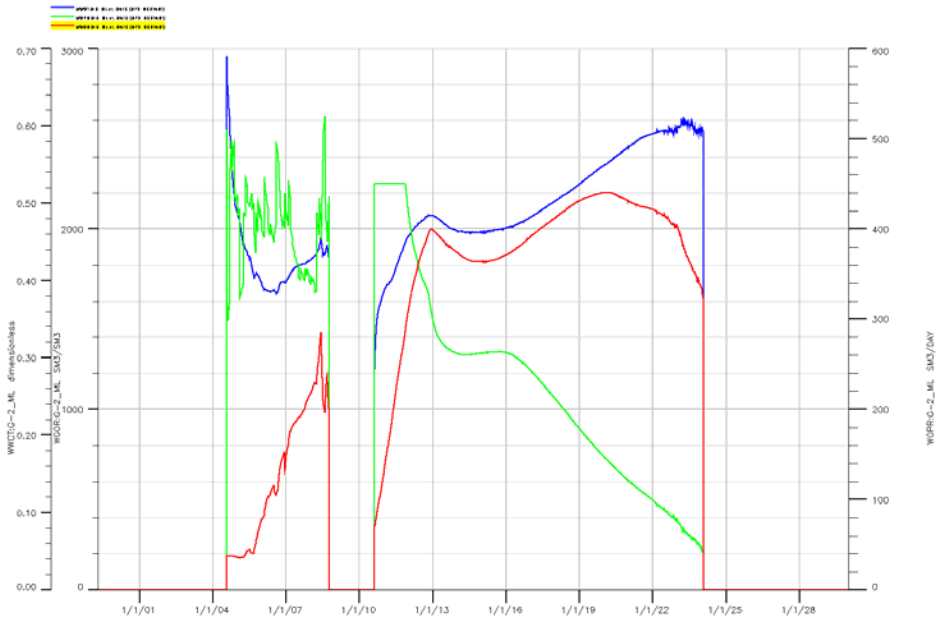


WOPR-F-4AT3H (Reference Case Vs Extended Case)

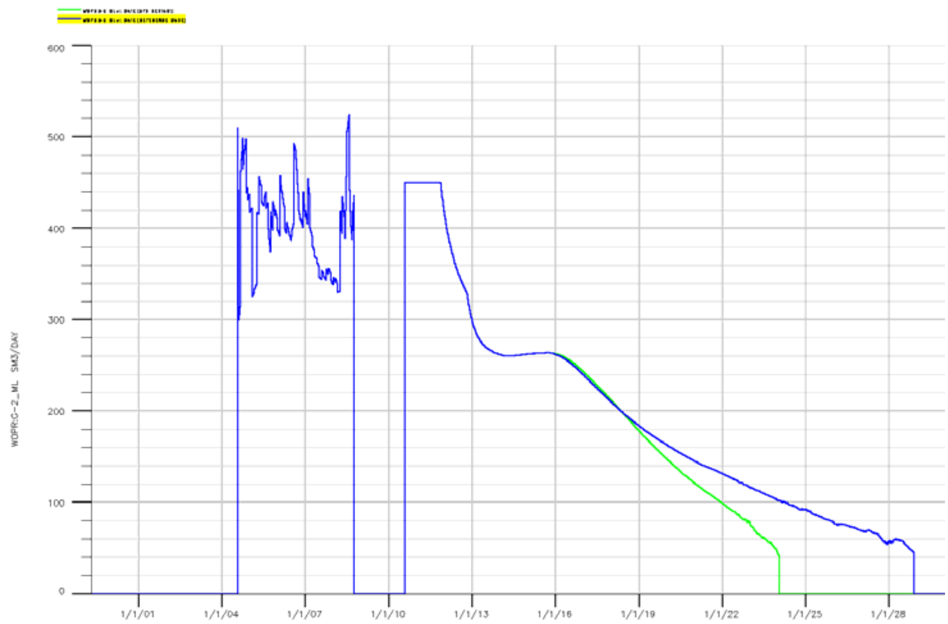


- The oil production rate from well F-4AT3H is lower for the extended case compares to reference case, and it is stopped producing on around mid of 2026.

G-2ML (Extended Case)

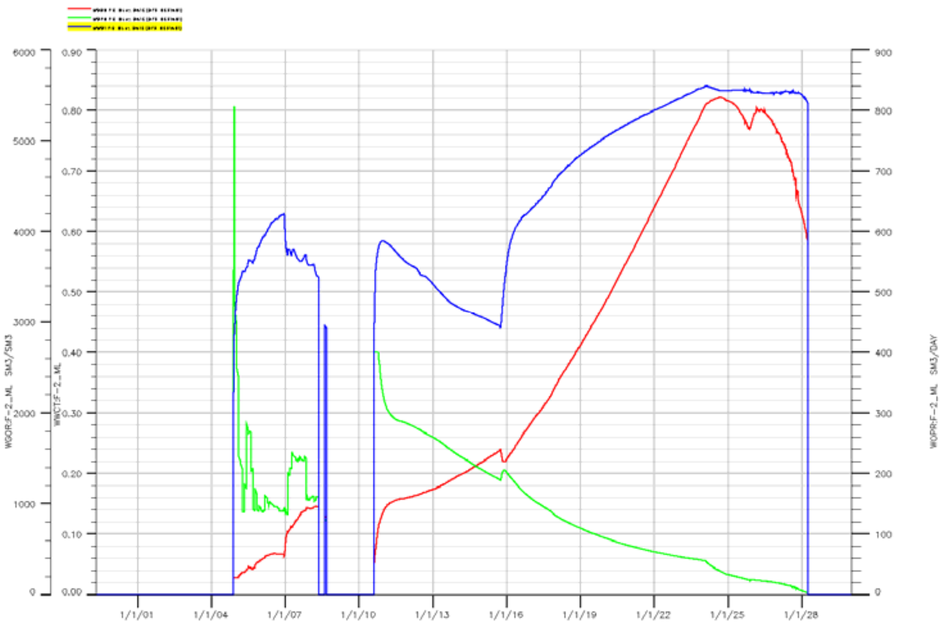


WOPR-G-2ML (Reference Case Vs Extended Case)

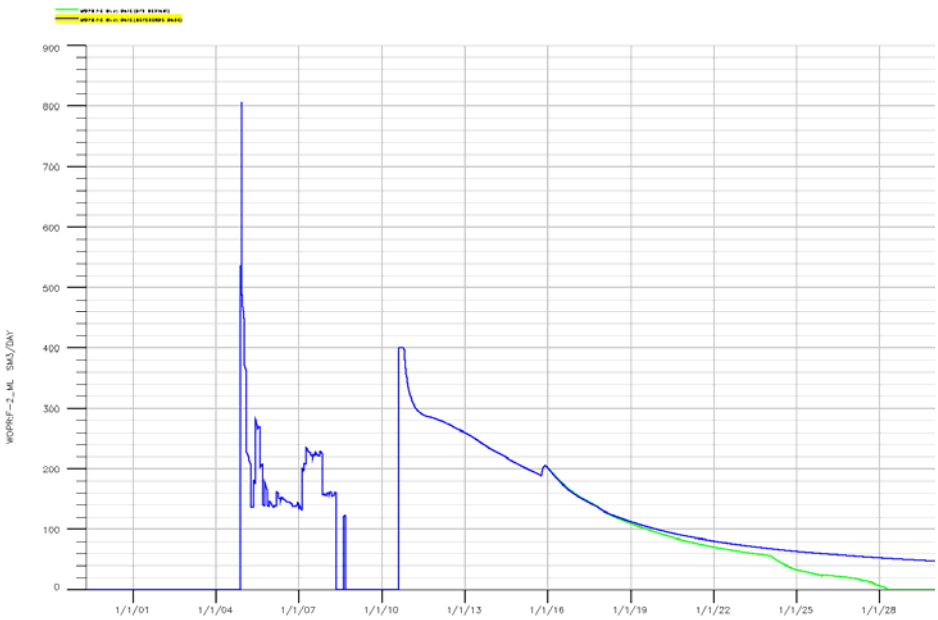


- The oil production rate from well G-2ML is lower for the extended case compares to reference case, and it is stopped producing on around mid of 2024.

F-2ML (Extended Case)

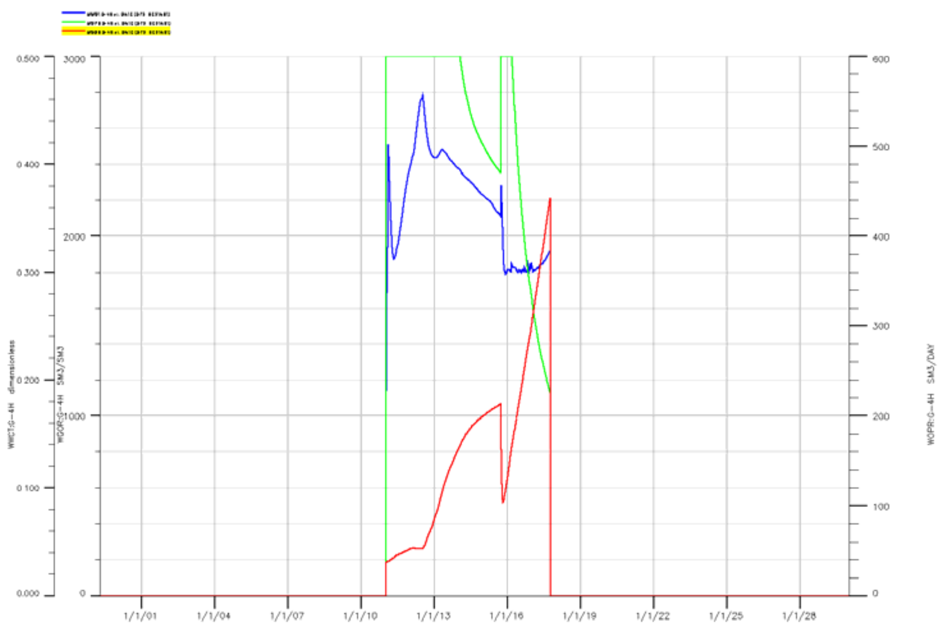


WOPR-F-2ML (Reference Case Vs Extended Case)

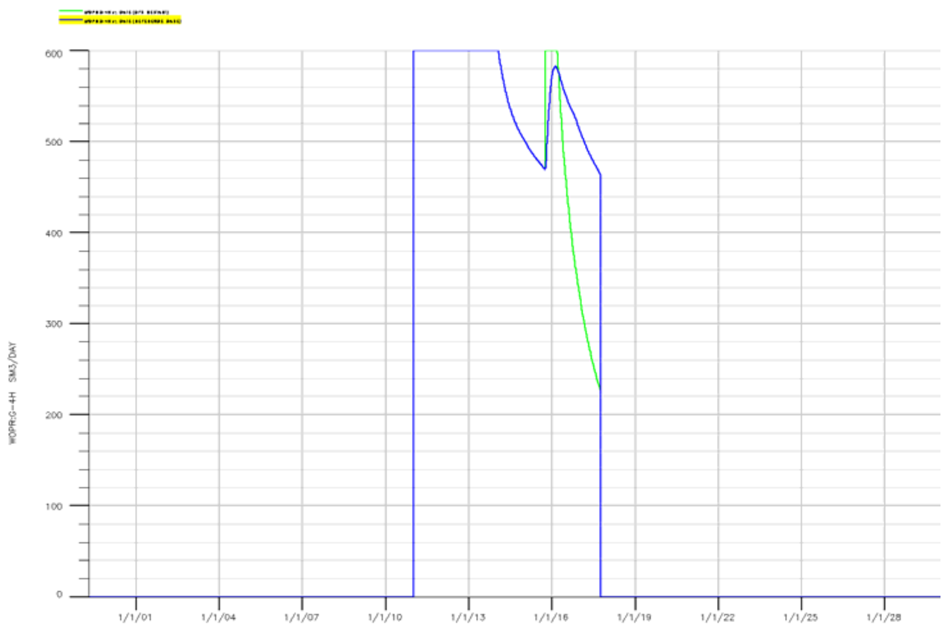


- The oil production rate from well F-2ML is lower for the extended case compares to reference case, and it is stopped producing on around early of 2028.

G-4H (Extended Case)

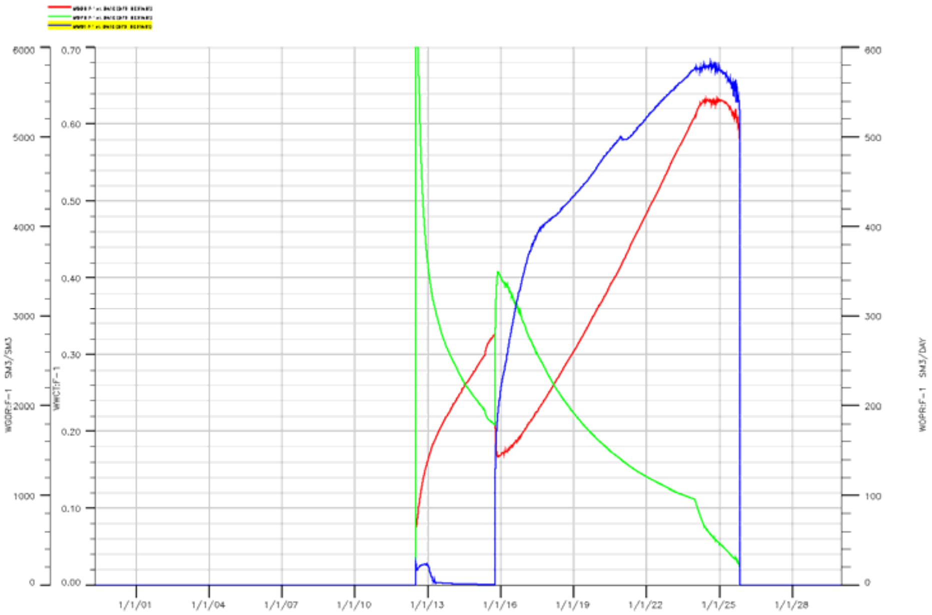


WOPR-G-4H (Reference Case Vs Extended Case)

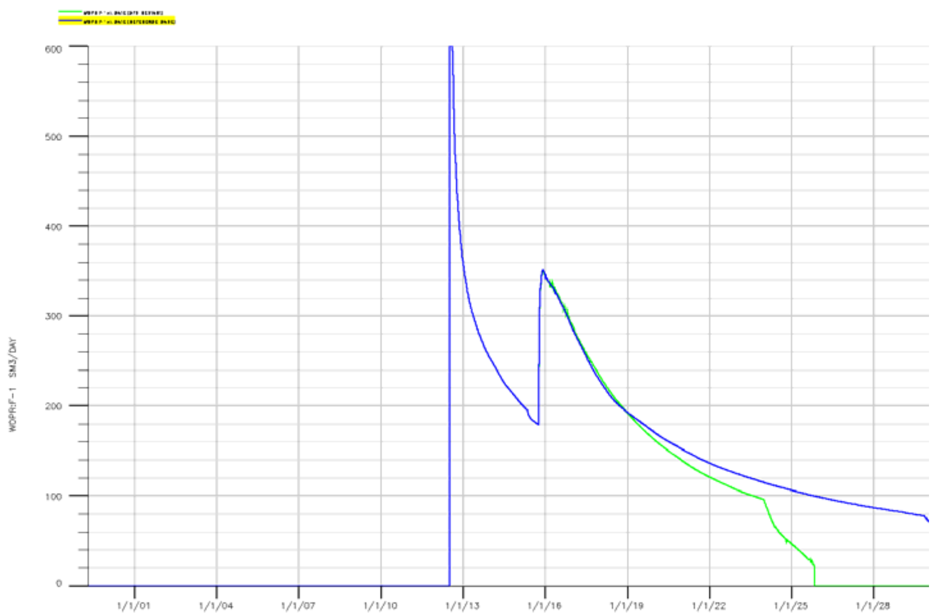


- The oil production rate from well G-4H is lower for the extended case compares to reference case, and it is stopped producing on around early of 2018.

F-1 (Extended Case)



WOPR-F-1 (Reference Case Vs Extended Case)



- The oil production rate from well F-1 is lower for the extended case compares to reference case, and it is stopped producing on around early of 2026.

Appendix C: Economic Calculations Worksheet

Economic assumptions

- Production is the same for platform and subsea
- Exchange rate 1USD = 6.28 NOK
- Discount rate is 7%
- Oil price is forecasted to be USD 110 on 2016, and increase 3% each year
- Gas price is forecasted to be USD 10 / MMBTU on around 2016, increase 3% each year
  - Gas heating value quality 1 mscf = 1 MMBTU
- Sensitivity analysis
  - Oil recovery +/- 25%
  - Gas recovery +/- 25%
  - Oil price +/- 40%
  - Gas price +/- 30%
  - CAPEX +/- 10%
  - OPEX +/- 15%
  - Discount rate +20% -10%
- CAPEX
  - Platform is cost 1750 MNOK
  - Subsea installation 1000 MNOK
  - Drilling 1 well from platform is cost 100 MNOK
  - Drilling 1 subsea well is cost 125 MNOK
  - Cost phasing for surface facilties is distributed in 5 years with configuration: 10%- 20%-30%-25%-15%
  - Cost phasing for drilling is distributed in 4 years equally
  - Abandonement cost for 1 platform well is cost 25 MNOK
  - Abandonement cost for 1 subsea well is cost 32.5 MNOK
- OPEX
  - Annual increament operating cost for platform is 75 MNOK, and increase by 3% per year
  - Annual increament operating cost for subsea is 50 MNOK, and increase by 3% per year

Oil Production Summary

	Cummulative Oil Production (MM M3)		
	Reference Case	Extended Case	Extended Case No Injection
Up to end of Sept 2016	6,32	6,32	6,32
Oct 2016 forward	2,55	7,12	4,73
Total	8,87	13,45	11,05
Oil In Place (IOIP)	42,20		
Recovery	21,02 %	31,86 %	26,19 %

Year by Year - Oct 2016 forward

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Extended Case	1,576999758	1,321668293	0,84906023	0,664257	0,545226	0,4636679	0,389927	0,332874	0,266782	0,215257	0,166171	0,118224	0,107684	0,10389	
Reference Case	0,410187623	0,463028335	0,237824754	0,206738	0,183351	0,1649726	0,14939	0,136175	0,125966	0,114199	0,104691	0,09655	0,087531	0,066425	
Increament (MM M3)	1,166812135	0,858639958	0,611235477	0,457519	0,361875	0,2986954	0,240537	0,196698	0,140816	0,101058	0,06148	0,021673	0,020153	0,037465	4,574657
Extended Case No Inj	1,513749522	1,163915853	0,800688656	0,608481	0,420575	0,1684507	0,052275	0	0	0	0	0	0	0	
Increament (MM M3)	1,1035619	0,700887517	0,562863903	0,401743	0,237224	0,0034781	-0,097115	-0,136175	-0,125966	-0,114199	-0,104691	-0,09655	-0,087531	-0,066425	2,181105

Well by Well - Oct 2016 forward

	G-2T3H	F-4AT3H	G-3T2H	G-1H	G-2_ML	F-2_ML	G-3Y3HT4	E-1Y3H	E-2BH	G-4H	E-3H	F-1	W1	W2W3	W4W5	W6W7	Total
Extended Case	0	0,281624765	0	0	0,474712	0,3606501	0	0	0	0,300753	0	0,59596	1,155972	1,418317	1,298101	1,235597	
Reference Case	0	418,4	0	0	281,74	313,8	0	0	0	74	0	522,7028					
Increament (MM M3)	0	-418,1183752	0	0	-281,2653	-313,4393	0	0	0	-73,69925	0	-522,1068	1,155972	1,418317	1,298101	1,235597	-1603,521
Increament (%)		-99,93 %			-99,83 %	-99,89 %				-99,59 %		-99,89 %					
Extended Case No Inj	0	0,182007973	0	0	0,3088	0,2388945	0	0	0	0,311365	0	0,419741	0,817372	0,849359	0,78748	0,813116	

Conversion

1 M3 6,289308176 barrel

Gas Production Summary

	Cummulative Gas Production (MM M3)		
	Reference Case	Extended Case	Extended Case No Injection
Up to end of Sept 2016	1680,03	1680,03	1680,03
Oct 2016 forward	7821,46	11711,65	10676,85
Total	9501,48	13391,68	12356,88

Year by Year - Oct 2016 forward

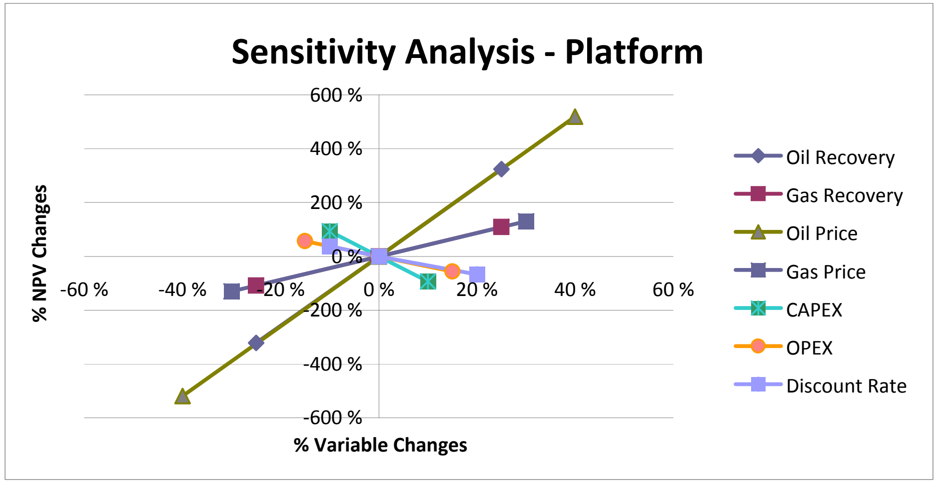
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Extended Case	533,1563965	1189,93893	1198,451429	1171,147	1148,217	1128,5572	1105,895	1081,042	987,2857	859,299	618,2446	282,2941	211,3145	196,8115	
Reference Case	619,1040204	802,4497038	603,6831491	584,9585	570,9737	559,60219	549,5615	539,2543	534,732	518,2794	504,9988	495,4366	482,5931	455,8281	
Increament (MM M3)	-85,94762388	387,4892262	594,7682795	586,188	577,2437	568,95499	556,3336	541,7878	452,5537	341,0196	113,2458	-213,1425	-271,2786	-259,0166	3890,199
Extended Case No Inj	1675,806692	2160,163592	2003,455388	2018,331	1728,017	831,41162	259,6652	0	0	0	0	0	0	0	
Increament (MM M3)	1056,702672	1357,713889	1399,772239	1433,372	1157,043	271,80943	-289,8963	-539,2543	-534,732	-518,2794	-504,9988	-495,4366	-482,5931	-455,8281	2855,395

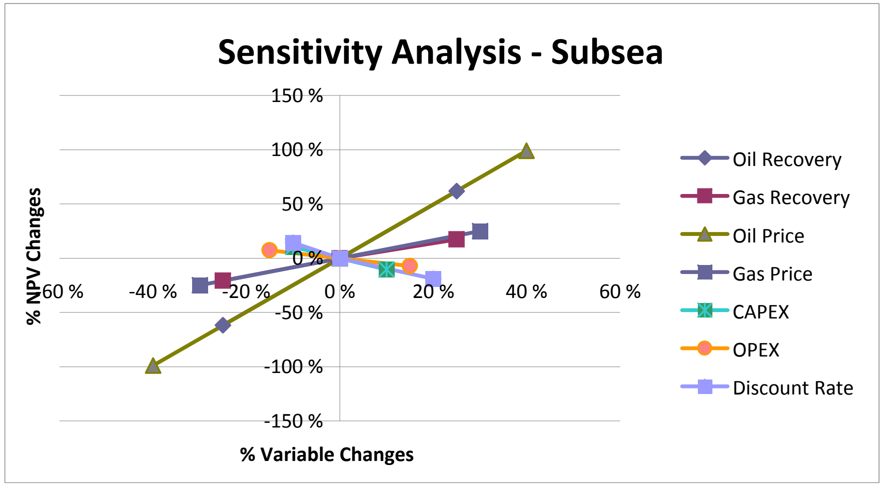
Summary

Economic Parameters (Increament)	Extended Case						Extended Case (No Gas Injection)	
	Platform			Subsea			Platform	Subsea
	High Case	Base Case	Low Case	High Case	Base Case	Low Case		
NPV (2010) - MNOK	2214,77	146,63	-1565,24	2837,74	768,75	-849,58	-443,79	98,44
IRR	30,69 %	9,16 %	--	43,63 %	21,39 %	--	--	21,23 %

Sensitivity

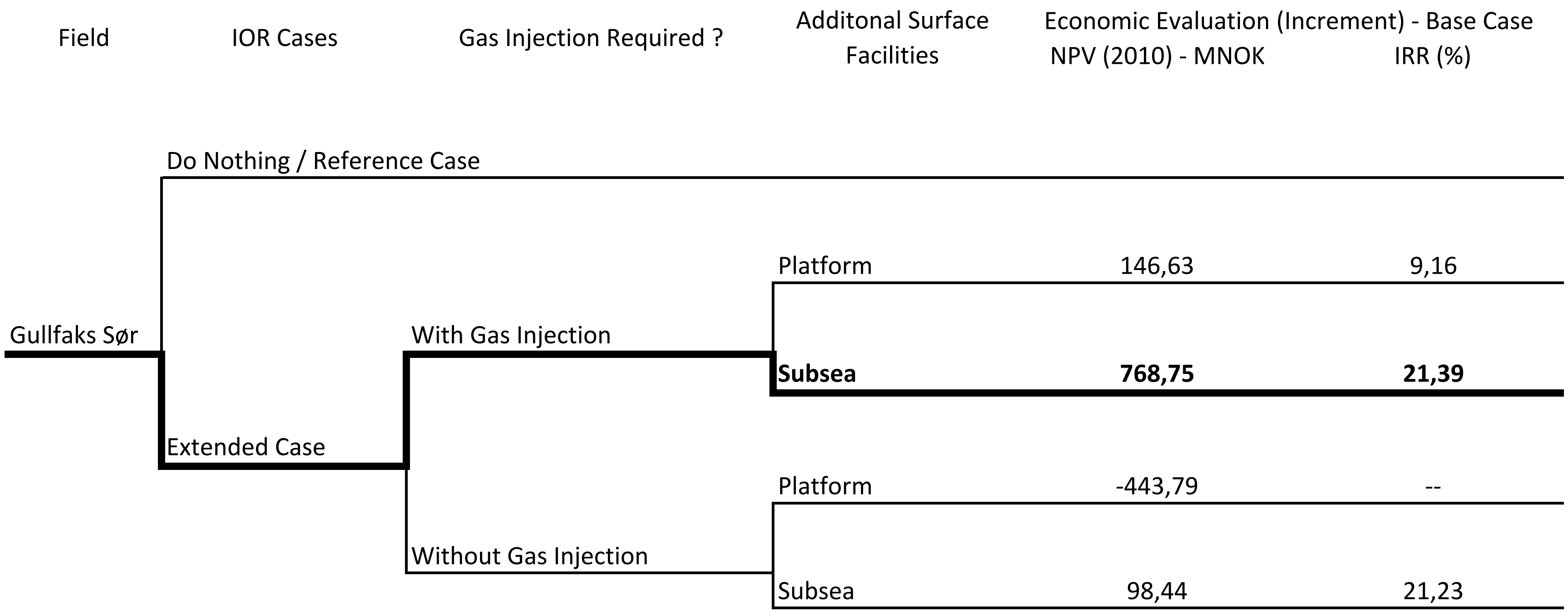
		Platform			Subsea		
		High	Base	Low	High	Base	Low
Oil recovery	% Sensitivity	25 %	0 %	-25 %	25 %	0 %	-25 %
	% NPV (2010)	325 %	0 %	-321 %	62 %	0 %	-62 %
Gas recovery	% Sensitivity	25 %	0 %	-25 %	25 %	0 %	-25 %
	% NPV (2010)	108 %	0 %	-108 %	17 %	0 %	-21 %
Oil price	% Sensitivity	40 %	0 %	-40 %	40 %	0 %	-40 %
	% NPV (2010)	519 %	0 %	-519 %	99 %	0 %	-99 %
Gas price	% Sensitivity	30 %	0 %	-30 %	30 %	0 %	-30 %
	% NPV (2010)	130 %	0 %	-130 %	25 %	0 %	-25 %
CAPEX	% Sensitivity	10 %	0 %	-10 %	10 %	0 %	-10 %
	% NPV (2010)	-93 %	0 %	93 %	-11 %	0 %	11 %
OPEX	% Sensitivity	15 %	0 %	-15 %	15 %	0 %	-15 %
	% NPV (2010)	-57 %	0 %	57 %	-7 %	0 %	7 %
Discount rate	% Sensitivity	20 %	0 %	-10 %	20 %	0 %	-10 %
	% NPV (2010)	-67 %	0 %	37 %	-19 %	0 %	14 %





Appendix D: Gullfaks Sør Part A Decision Tree

Part A Decision Tree



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