IMPROVED OIL RECOVERY

GULLFAKS SØR STATFJORD

EXPERTS IN TEAM

TPG-4851 GULLFAKS VILLAGE

GROUP – 6

NTNU – TRONDHEIM

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Abstract

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 satellite. There is a lot of hydrocarbon potential in the Gullfaks Sør field, in which the current predicted oil recovery factor is only 18.75% up to 2030. This study is intended to assess the field development possibility and to achieve a 10% improved oil recovery (IOR) from the Statfjord formation within Gullfaks Sør.

The IOR program at the Gullfaks Sør field faces many challenges. The most distinct challenge is related to the geological uncertainties. The reservoir sands are deposited by a fluvial system which is hard to be accurately predicted / modelled and is very vulnerable to tectonic activity. There are many faults and cementation which reduce the communication within the reservoir. The quality of the seismic images is not very good, because of the overlying geology that disturbs the reflection of the seismic waves and there are also strong sea bottom multiples. The existing wells are not spread but located in one certain part of the reservoir, and that makes it difficult to do the geological correlation across the whole reservoir. Due to these uncertainties, understanding the impact of the predicted worst case scenarios in the reservoir condition is necessary as a part of the IOR study.

Statoil's own study for an increased 10% oil recovery has been used as a base case on which we have tested several development scenarios. The scenarios have expanded based on the following tests. We have assessed the need for gas injection, compared the field development with subsea facilities versus installing wellhead platform, and assessed the impact of setting all faults to have zero transmissibility that includes placement of additional wells.

The study concludes the following; Gas injection is required to get an additional 10% oil recovery. The subsea facility development concept gives higher economical value than the wellhead platform case, and positive incremental economical value compared to ‘Do Nothing’ case. When closing off the transmissibility across the faults, four new wells are required to get an additional 10 % oil recovery, and that also gives a positive incremental economical value compared to the ‘Do Nothing’ case. Modifying the trajectory of the new wells in the initial Statoil’s development scenario, can give less risk for the oil recovery for the worst case reservoir condition.

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A. Background

I. Overview

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.

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 the Statfjord formation.

II. Study Objective

The objective of this study is to achieve an additional 10% oil recovery from the Gullfaks Sør field up to the end of the field license (1 January 2030) by assessing several development scenarios, the geological and geophysical uncertainties, and the economic impacts on the field development.

The development scenarios should cover the below aspects as a minimum:

- Assessing the need of gas injection (gas injection scenario versus no gas injection scenario)
- Comparing field development with subsea facilities versus installing wellhead platform
- Assessing the impact of the field development on the worst case reservoir condition, by setting all transmissibility across faults to zero. This includes assessing the additional wells required to achieve 10% IOR, with this worst reservoir condition.

B. Gullfaks Sør Reservoir Characteristics

I. Geological and Geophysical Uncertainties

There are many uncertainties that must be considered when dealing with a fluvial system. The fact that sediments deposited by a river are not organized in an easily predictable manner, but in a way which is different from one place to another even though the depositional mechanisms are the same, makes it very difficult to make a static model that works. In order to understand the mechanisms better we have to look into what fluvial systems are, and then it may be possible to work from that and make the individual predictions for one reservoir considering tectonic movements, climate, diagenesis and other things that influence a deposition.

a. Fluvial systems

A depositional environment is defined as an area where sediments are deposited, and where physical, chemical and biological elements along with the geomorphology, the climate, the water depth and the sediment supply decide the distribution of sediments.

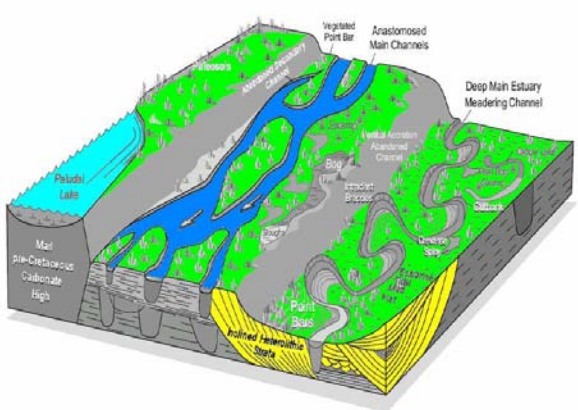


Figure 1 Different depositional environment (source: www.subterranetech.com 2010)

A fluvial system is defined as a continental depositional environment where rivers are the main mechanisms for deposition of sediments. The rock types that can be found where there has been a fluvial environment vary from conglomerate and sandstone to clay and shale. The reason for the great variety is that the different energy levels in the rivers are responsible for the deposition of the different grain sizes. The type of channel is affected by the gradient, the sediment load and the velocity. A low gradient favours a meandering river, while a high gradient and a high sediment load favours a braided river.

A fluvial system can be located in several settings, especially on the different fans: alluvial fans, deltas and in estuaries. An alluvial fan is found up by the mountain, a delta and estuaries are located in the transition zones between marine and continental settings. It is in the channels where the water flows that the sediments are deposited.

Braided rivers

A braided river consists of many river channels with braid bars in between, it is an unstable river system and the bars move about as the channel velocity changes. The rivers are divided into gravel dominated and sand dominated; the gravel dominated will turn into sand dominated downstream. The deposition of sediments is of course dependent on the material transported in the channels.

Figure 2 The Waimakariri river in the South Island of New Zealand (source: Wikipedia)

There are three main types of bars that are created in a braided river, longitudinal, transverse and lateral bars. The longitudinal bars are deposited in the middle of a channel when the velocity decreases and the coarse material is released from suspension. Finer grained material will then use the little abruption, and get deposited in the shelter behind it or on the sides. This kind of bar will migrate downstream and laterally. The transverse bars are more typical for the sand dominated rivers and are deposited as large ripples during a flood. The lateral bars are deposited in low energy areas on the sides of the channels.

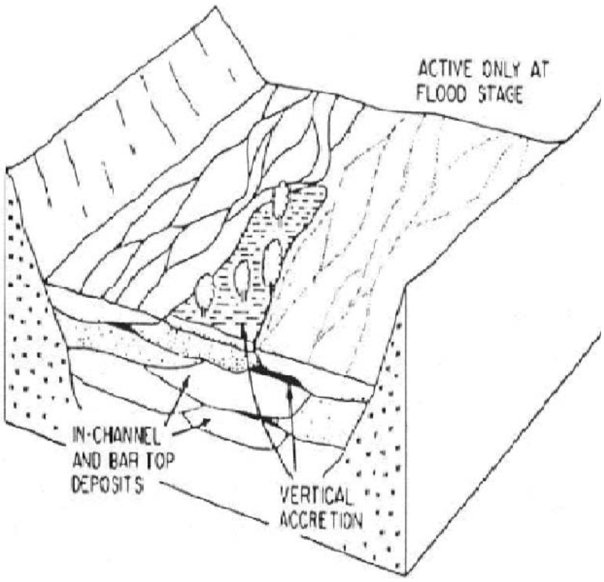


Figure 3 Deposition of sand and gravel in a valley caused by a braided river (source: Sam Boggs Jr. 2006)

As illustrated in figure....lateral migration of braided rivers leave sheet like or wedge-shaped deposits of channel and bar complexes, lateral migration combined with aggradations leads to deposition of sheet sandstones and conglomerates that enclose very thin, no persistent shale within coarser sediments. Braided river deposits fill the available accommodation space. A general faces association in braided river deposition is fining upwards.

Meandering rivers

A meandering river is a high sinusoidal channel with cohesive banks which are not easily eroded. The river has a low topographic gradient and transport fine grained material like sand, silt and clay.

Figure 4 Sacramento River, California (source: Wikipedia)

Inside the meander belt the river migrates downstream and sideways. In a meander turn the water moves in a helical flow as the water moves up on the inner turn and downwards on the outer turn. While moving down the velocity is high and the water erodes the sediments on the bank while moving upwards the velocity is decreasing and sediments are deposited in a fining upwards trend. This movement creates point bars.

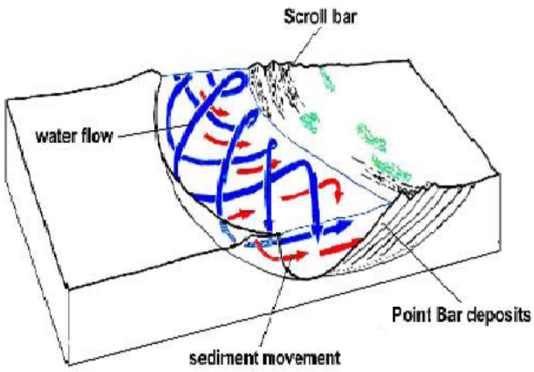


Fig 2: Cross section of a meandering stream channel

Figure 5 The water movement on a meandering river and the creation of point bars (source: Johnsen 2009)

The point bars are added next to each other and create bodies that have sections of sediments with a fining upwards trend. This means that the coarser material is deposited first followed by sand and mud at the top.

As the meander belt is experiencing aggradations the bottom of the channel may get higher than the floodplain that may cause an avolusion which means that the river breaks out and starts to form on a lower level. This generates several linear «shoestring» sand bodies oriented parallel to the river course. These shoestring sands are surrounded by finer grained overbank floodplain sediments.

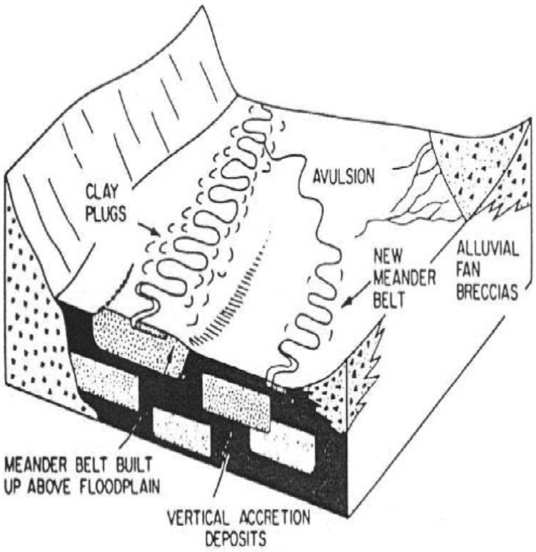


Figure 6 Avolusion of meandering rivers starts new meander paths (source: Sam Boggs Jr. 2006)

Other features that can be linked to a meander system are scroll bars, levees, crevasse splays and abandoned channels (oxbow lakes). A scroll bar consists of coarse material and defines the shape of an old point bar. Levees are built up by sediments deposited along the outer turns of a channel when the river floods, the coarser material close to the channel and the finer material is transported further out on the edges. A crevasse splay is deposited if the river breaks the levee at some point and sediments are splayed over the edge as a fan. An abandoned channel will with time be filled with fine grained sediments as there is not much water movement in it. It is created when the meander moves laterally and two outer turns connect and the rest is cut off.

Fluvial systems as reservoirs

A braided river can act as a wonderful reservoir as there is mostly sand and gravel deposits and not very much silt and clay. This may give good reservoir properties like high porosity and good permeability. The deposits are usually heterogeneous and that may affect the flow of fluids in the reservoir. Multiple episodes of channel shifting and bar migration in braided rivers produce vertical stacking of bar deposits, perhaps separated by thin mudstones.

A meander system can also act a good reservoir, but as the sediments are deposited like shoestring bodies covered by fine grained sediments it might be harder to find the good spots. The deposition is homogeneous and that may help the flow of fluids. Crevasse splays are usually perfect sand bodies for reservoirs and can get very large as one opening in the levee may by used several times. Multiple episodes of meander migration produce vertical stacking of fining-upward succession in meandering river deposits.

Reservoirs of fluvial systems in general

Fluvial depositional characteristics give rise to a complex reservoir architecture and geometry, spatial distributions, internal heterogeneities and petro physical properties as well as connectivity of channels. This gives great uncertainties in characterizing the effective reservoir properties.

One fluvial environment is very different from another. They do show some of the same trends but there are so many different things that affect the deposition. Depending on the sediment load at the time of deposition the spatial distribution is different and hard to predict. When it comes to internal heterogeneities, it could be everything from the grain size and distribution to what kind of sediment it is, it could be cracks, cementation and different porosity among others, but it is all made a little trickier because the patterns can change from one channel to another. Internal anisotropy and sporadic permeability barriers can only be detected after many wells have been drilled.

One important flow barrier which is abundant in fluvial systems is the interstratified shale beds. These can be hard to come around, as they act as horizontal flow barriers. The sand bodies are also highly sensitive to tectonic, climatic, hydraulic and geomorphic conditions, and these may be difficult to ascertain in a given basin.

It is generally assumed that the continuity of the main reservoir sand bodies will be best parallel to the paleo slope. Crevasse splay sands which constitute significant reserves in many fields are extremely difficult to locate and delineate as they move away from the general direction of the main sand bodies.

b. Depositional models

Models for all depositional systems likely to work as a reservoir have been made. The problem with the depositional models for fluvial systems is that they are too large in scale. Even though the systems are large the individual channels cannot be taken as one, because there are so many details. It is also demanding to correlate major units from one well to another to establish gross connectivity pathways and then also the subtle detail.

Seismic data is used when trying to make a model of the subsurface, poor data and low resolution makes the geologist and the reservoir engineer depend on borehole data when predicting the unclear regions.

Usually detailed descriptions of outcrops may help the geologist and the reservoir engineer with prediction of the subsurface, but when it comes to fluvial systems it might be risky to predict too much from other localities which we think are similar. This constitutes a great challenge as almost all assumptions are based upon the depositional model.

Because of all these uncertainties, there are many misinterpretations of fluvial systems in the world.

Depositional history Gullfaks Sør

The sediments in the Statfjord formation are deposited during the late Triassic and the early Jurassic. The lower part shows an alluvial environment with periodical flooding events. Upwards in the formation the environment changes to a poorly drained alluvial plain with swamps and river channels. The upper parts are mostly fluvial and all the way to the top there have been spotted some tidal channel events in some of the wells. These are estuarine channels and it implies a transgression. The Amundsen formation has marine shale and that indicates a total flooding of the area.

The stratigraphic column made from well 34/10-30 shows the sediments found at the Gullfaks Sør in more detail. The Statfjord formation shows characteristics of a braided fluvial system, in the Nansen, Eriksson and Raude members. When forming the Nansen member, the river has had a very high sediment supply and Nansen therefore has the best properties. Further down into the Lunde formation the system changes to a meandering system.

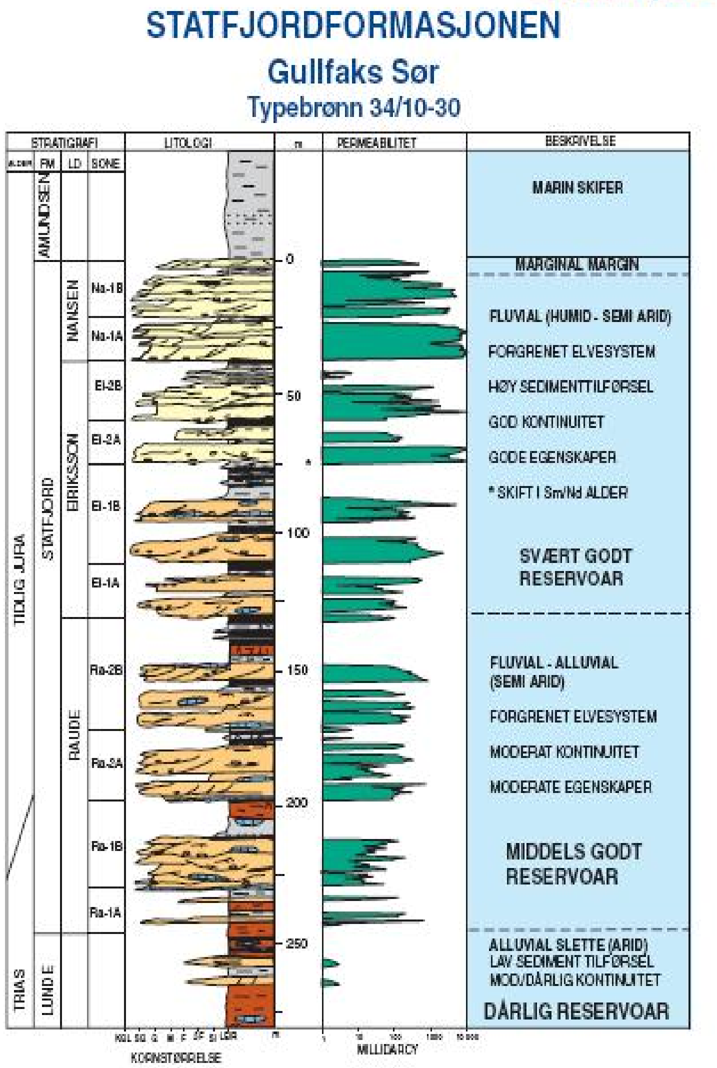


Figure 7 Stratigraphic column well 34/10-30 Statfjord formation (source: Statoil 2007)

The deposition of the Statfjord formation was done in an active tectonic period. The easternmost part has been lifted as a consequence of faulting. The southern part of the reservoir is also steeper than the rest because of this.

c. Reservoir description

The main direction of the fluvial system at the Gullfaks Sør field has been greatly discussed and the understanding of it has changed several times after predicted behaviour has been different from the real results. Now, Statoil thinks that the main direction of the river system is north-south. The fluid flow in the reservoir goes in several different directions.

The zoning in the reservoir is mostly lithostratigraphic and it has been tried to divide between sand dominated intervals and shale dominated intervals, it is mostly the same as in the main field. The zoning is based upon analyzes from cores and cuttings.

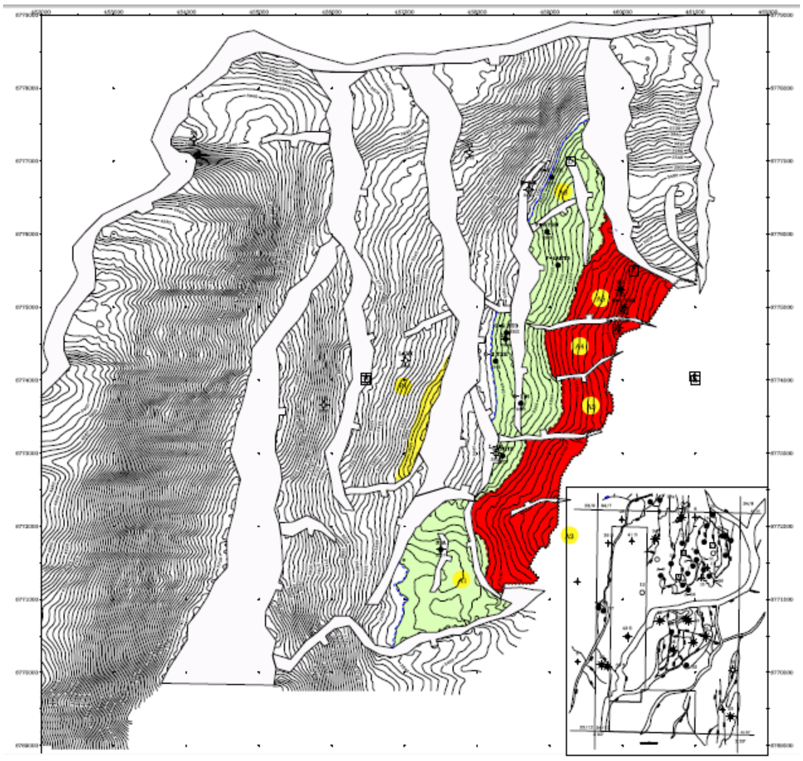


Figure 8 Structural depth map of top Statfjord (source: Statoil 2007)

The Statfjord formation has been divided into segments, A1- A6 and one segment called P1. These segments are divided by faults. There has been proved communication across the fault between A5 and A4 in Nansen and Eiriksson3.

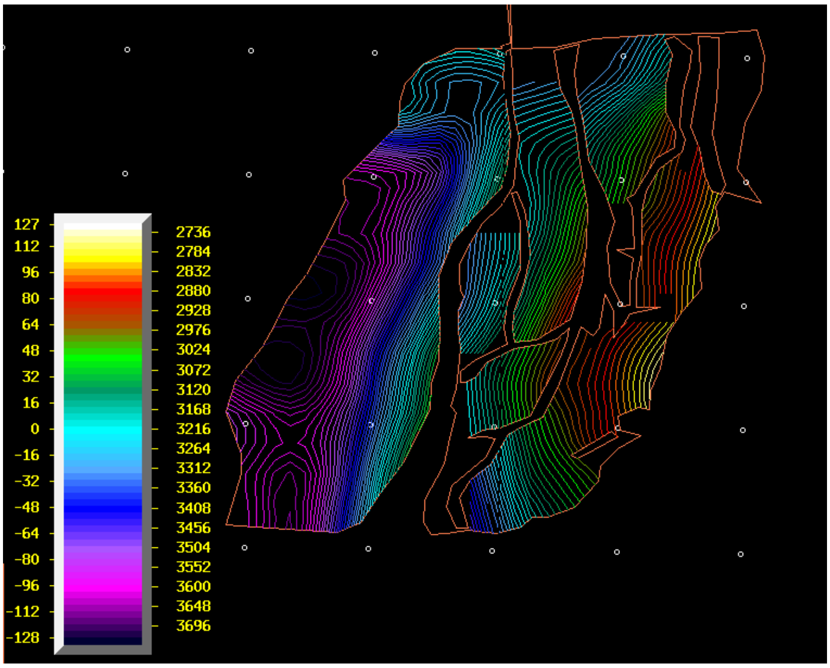


Figure 9 A contour map of the Statfjord formation generated from the interpretation on survey ST99M06, interpretation by Statoil

Nansen and Eiriksson are massive and laterally homogeneous and high permeable (0.5-2 D) sands with some interbedded shale and coals. Nansen is laterally continuous. The lower part of Statfjord, Eiriksson1 and Raude are frequently changing from shale to sands of varying thickness and quality. Raude shows red shale and soil profiles. At the bottom part there are some kaolinite and feldspars.

d. Main uncertainties at Gullfaks Sør

Poor communication between the segments in the reservoir

There are several factors that cause the poor communication. The result is problems when producing, because then we want to drain the reservoir in an efficient way. When there is poor communication it is hard to plan the different wells, and especially in the Gullfaks Sør field because the drilling of wells is limited as the overlying Brent formation is unstable because of high depletion.

The most important reason for the poor communication was found during a structural geological study performed in 1999 which was based on cores. The study mapped several deformation bands with affiliation to the faults. The leap across these micro faults /deformation bands ranges from mm-scale to cm-scale. That has led to dissolution and re-crystallization of quartz which reduces the permeability across the bands.

There have also been proved sealing faults on the Statfjord level, and therefore we can say that structural segmentation and stratigraphic barriers cause the complex communication.

A way to find out more about the communication in the reservoir is to run well tests, this has been done to some extent but because there is a limit to how many wells it is justifiable to drill in the field because of the overlying depleted Brent formation, it is hard to get pressure data from all the different segments.

Problems with maintaining the pressure when producing

When injecting gas into the reservoir, the pressure has not been maintained in the same way as proposed. This is caused by no communication between the gas cap and the oil in the reservoir. And therefore the field has been shut in to build pressure before further production.

Both the simulation of the reservoir and the well testing data supports the idea that the pressure has decreased rapidly. There are a few problems concerning this though, the data showing this trend might not be applicable for all segments of the reservoir.

The tuning of the reservoir model is not quite complete, as there is some lack of data and it is not comprehensively analysed. For instance, the uncertainties for communication in segments 1, 2 and 3 are too big as there are no existing wells there. There is also no information on tuning the history match using pressure data.

Poor seismic quality

For being able to plan a field there should be a clear idea of how the reservoir looks like. This is done by looking at and interpreting seismic images. For Gullfaks Sør, this has not been very easy. There are several reasons for the poor seismic data quality on the Gullfaks Sør field.

- Strong multiples from the water layer
- Shallow gas (mostly in the east)

- Gas in Tertiary and Cretaceous
- Energy being scattered because of a large number of fault blocks and overlying moraine deposits.
- Reduced reflections and large amplitudes caused by Norske Renna

Strong multiples are noise in the seismic data and they can be difficult to remove completely. This destroys the picture as they look like reflectors but they are only artefacts created by multiple reflections coming from the energy which has bounced in the water layer. There might also be peg legs which are multiple energy from the internal layers of the subsurface.

Gas in the sedimentary rocks will disturb the seismic pressure waves and the signal will be attenuated. This is caused by the way the gas is situated in the pores of the rocks and affects the waves when they travel through.

When seismic energy hit sharp edges it gets scattered in other directions and the signal is attenuated. There are some shallow glacial deposits above the Gullfaks Sør field and they contain grains of many different sizes which have scatter effects. There are many faults and cracks that make the surfaces very uneven.

The seismic data quality is generally best in the western and northern part. There has been acquired 4D seismic, but it has not shown the wanted results. There has also been a Ocean Bottom Seismic (OBS) study, ST0302, which has been used to verify the former interpretation of the horizons and faults which is done on the ST99M06 survey. The reasons for doing an OBS is that shear waves are detected at the geophones on the ocean bottom and they are not affected by gas in the sediments and can therefore give a clearer image.

The reflectivity in the Statfjord formation is dependent on the lithology and the fluid saturation. Water filled sand shows a reduction in acoustic impedance, a thick carbon leading sand has a even greater reduction. The top Statfjord is cemented and shows an increase in acoustic impedance.

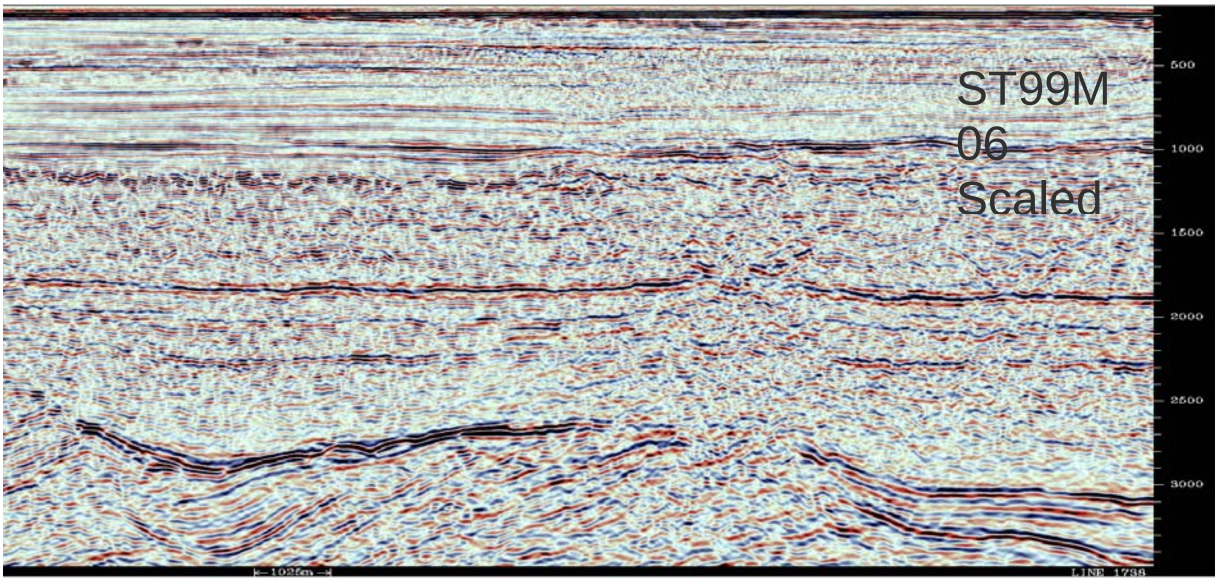


Figure 10 Illustrates the poor quality on the seismics in the area, a gas chimney can be spotted to the east (source: Gullfaks Sør Omega – introduction)

When looking at the reservoir in detail on the seismic, it is evident that the different horizons are hard to pick as it seems like there is a lot of noise in the data below BCU.

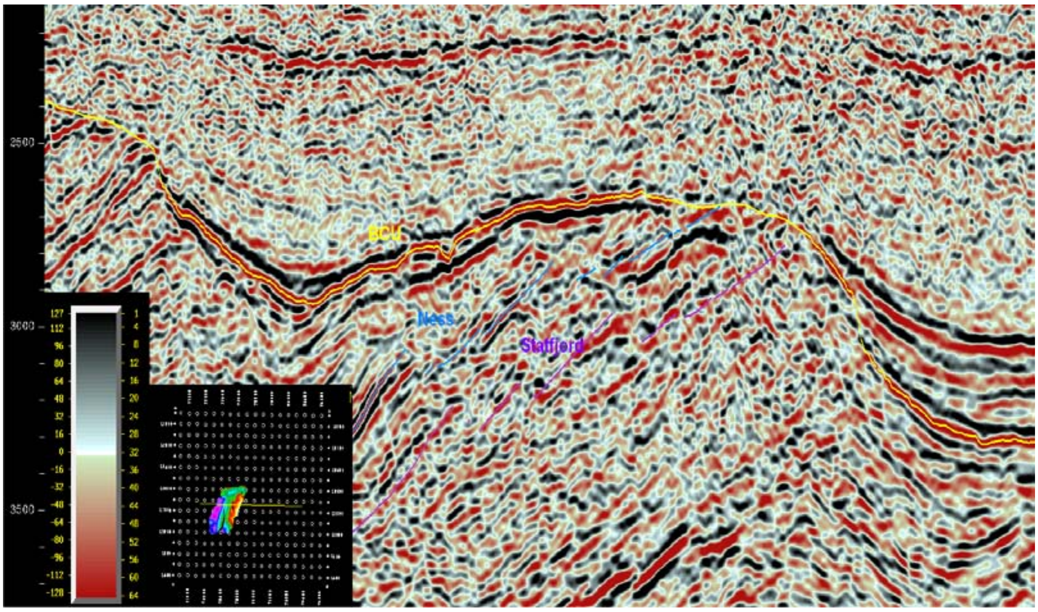


Figure 11 Line 1742 on the ST99M06 survey shows the reservoir in detail, interpretation by Statoil

Confidence when picking the faults on the seismic

The faults are not very easy to see on the seismic. It is barely visible that there are some dipping layers and they are continuous as in a domino system. The confidence in picking the faults is better towards the west. The eastern part is very obscure and the interpretation of the horizons seem like they have been forced through. The big faults are to some extent visible as the different packs can be observed. But there has been a core study that proved micro faults and obviously the resolution is not good enough for placing those on the seismic.

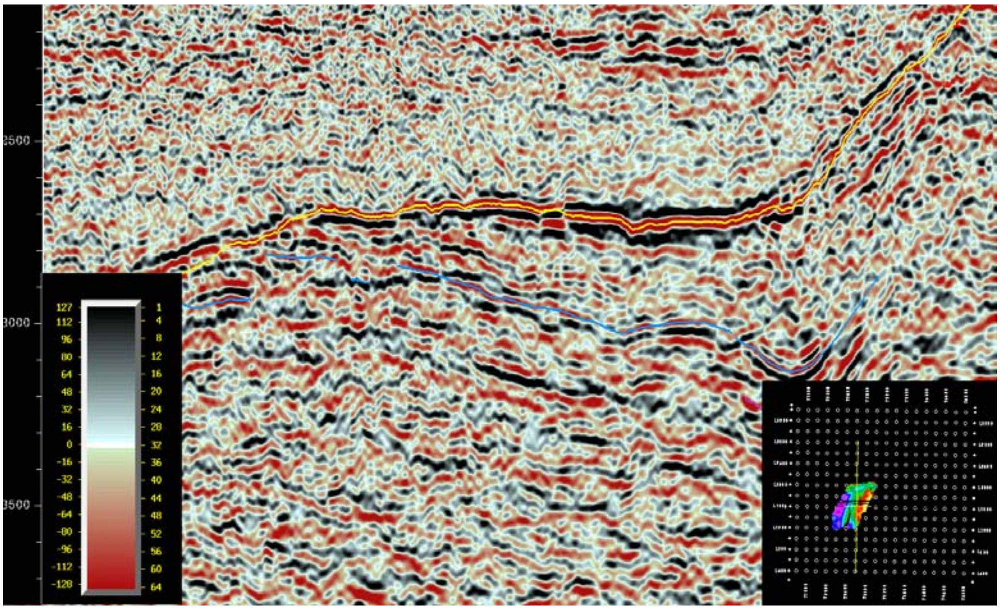


Figure 12 Trace line 2610 from survey ST99M06, the reflections are fuzzy

d. Conclusions about the uncertainties at the Gullfaks Sør field

There are many matters that make the planning of the Gullfaks Sør field challenging. The fact that it is difficult to make good seismic images, hard to find a geologic model that can help predicting the unexplored areas and the terrible communication between the segments make the reservoir engineers think in new directions as the regular procedures may not be used. Mostly all data and models from the field are based on cores, cuttings and well logs. As well data and cores are not very representative for a whole field and there are not very many wells to get data from, the models and conclusions have been changed as the production has gone by. That makes it very difficult to predict and seems to be the main reason for why the field is shut in. There should be a model that could make the engineers plan better for the field because we know that it has a lot of resources.

Our group has tried to manipulate the reservoir model by setting the transmissibility of the faults between the segments to zero. The reason for that is that we think that the reservoir is tighter than first predicted and setting the transmissibility to zero is the worst case.

II. Gullfaks Sør Reservoir Engineering Characteristics

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.

a. General properties

Gullfaks Sør (Statfjord Formation) main reservoir data are as follow:

- 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
- Bubble point pressure 220 bar
- Initial temperature 128 C (at 3300 m MSL)
- Gas gradient 0.0291 bar/m
- Oil gradient 0.0693 bar/m
- Water gradient 0.103 bar /m
- Temperature gradient 0.032 (C/m)
- Top view size of the reservoir 4 km x 7 km

b. Resources & Reserves

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

	Oil/ Condensate (MSm3)	Gas (GSm3)
Originally In Place	42.20	19.03
In Place per 1 Oct 2015	37.62	17.61

		Initial Oil In Place			
Segment	**FIPNUM**	**NANSEN (MSm3)**	**EIRIKSEN (MSm3)**	**RAUDE (MSm3)**	**TOTAL OIP (MSm3)**
A1	70	1.47	0.32	0.00	1.79
A2	60	3.38	6.43	0.84	10.64
A3	30	3.51	5.46	0.54	9.51
A4	20+10	2.51	2.80	0.44	5.74
A5	120+130	6.61	4.22	0.80	11.63
A6	140+150	2.51	0.33	0.00	2.84
					42.20

Table 1 Initial oil in place

The reservoir is defined per area, which is segregated based on the faults around it. This segregation makes it possible to analyze and assess the productivity and potential each areas that helps to understand the reservoir characteristics in overall. Analysis based on reservoir formation is also necessary.

As described in the table above, it can be clearly understood that area A2, A3 and A5 have the highest oil potential, in which most of them are located in Nansen and Eirikson formation.

c. Drive Mechanism

The existence of water can be easily identified in this field, especially after production period. The most difficult reservoir characteristics to be found is drive mechanism, which in some way related with the size of the aquifer inside of the reservoir. The size of aquifer is important in correlation with supplying energy (as pressure support) to the oil to be recovered.

Gullfaks Sør field has the weak water drive characteristics (or depletion type of reservoir). This affects the level of oil recovery from the field, which reservoir pressure maintenance effort is the key component for the successful of the improved oil recovery on the field. Gas injection / water injection should be considered as key solution factor in achieving additional 10% improved oil recovery within the field.

FAULTS MAP

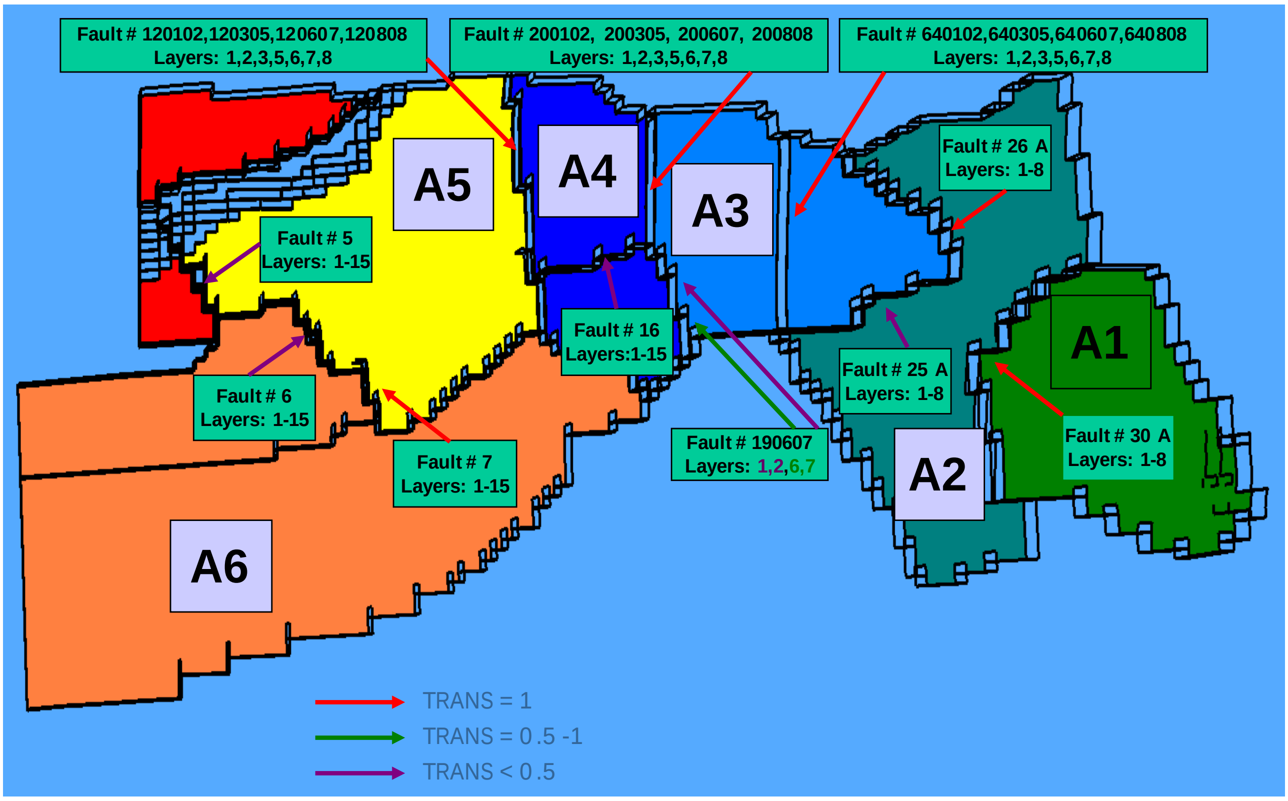


Figure 13 Gullfaks Sør – faults map

C. Improved Oil Recovery Scenarios Development

I. IOR Scenarios Development Basis

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.

Some basis on developing field development scenarios are:

- Assessing the need of gas injection (gas injection scenario vs no gas injection scenario)
- Comparing field development with subsea facilities vs installing wellhead platform. There are some main differences between development using subsea or platforms:
  - Capital and Operational Expenditures, which platform is a high capital option and subsea is high operational cost option.
  - Well efficiencies. Due to the maintainability and easier access for well intervention, platform's wells have higher efficiency than subsea wells. For this simulation, subsea wells efficiencies are assumed to be 90% and platform at 95%.
  - Wells minimum tubing head pressure (THP). Platform has the flexibility of treating the flow stream prior to send to the processing platform, which can give pressure minimum backpressure reduction, which means extending the well stream further / improving hydrocarbon recovery from the reservoir. It is assumed in this simulation that minimum backpressure for subsea development is 90 bar and platform is 60 bar. Further reduction of platform backpressure is possible, depends on how far the flow treatment in the platform (as examples: produced water treatment, booster pump and compressors in the platform)
- Assessing the impact of the field development on the worst case reservoir condition, by setting all transmissibility across faults to zero. This includes assessing the additional wells required to achieve 10% IOR, with this worst reservoir condition.

Gullfaks Sør Eclipse Model

The Eclipse model of the Gullfaks Sør field, block 34/10, consists of 64 x 110 grids and 15 layers in Statfjord formation. The layering in the model represents the geological zonation in the Statfjord formation, and is presented in table 2. The top view size of the reservoir is 4 km x 7 km.

Formation	Layer
Nansen	1-8
Eriksen	9-13
Raude	14-15

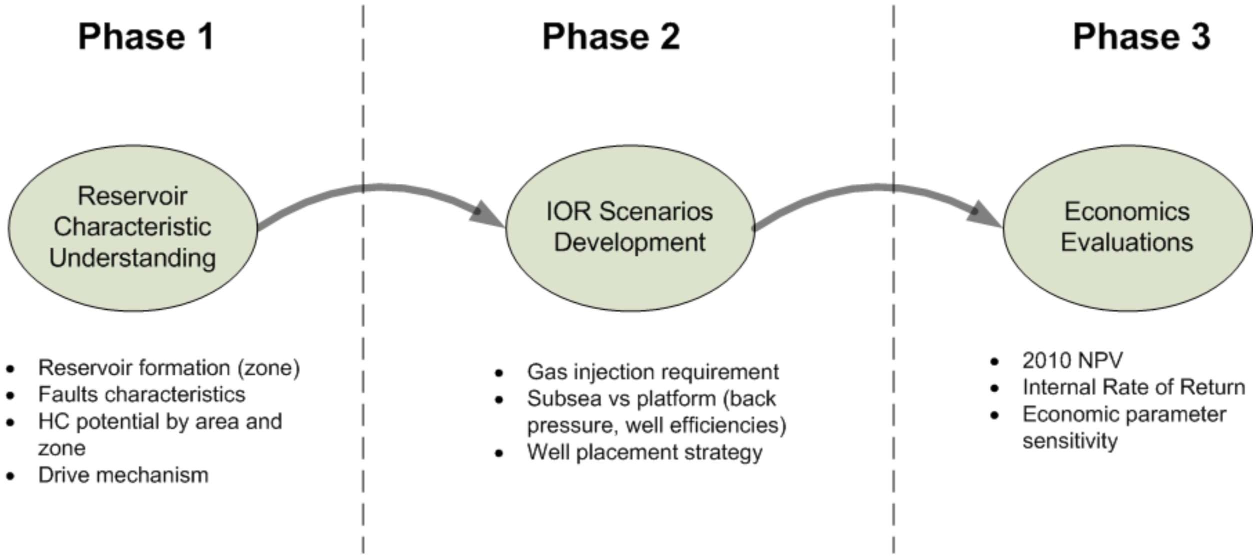
Table 2 Allocation of geological formation in the Eclipse Reservoir modelling

The simulation in the model starts from 13 'APR' 1999. The reservoir is 3 phase dry gas (oil, gas, water) occupying a volume of 42.20 MSm^3 of oil and 19.03 GM^3 of gas with a bubble point pressure at about 220 bara. The initial reservoir pressure is 476 bara.

The reservoir is divided into six segments A1, A2, A3, A4, A5, A6 and is isolated by faults. There are 2000 faults in the model, each having different transmissibility varying from 0 to 1.

The water oil contact is located at a depth of 3362 m MSL and GOC at 3224 m MSL. The underlying aquifer seems to be smaller in size and reservoir is assumed to be a depletion type.

II. Reservoir Simulation on IOR Scenarios



The study mainly is divided into 3 phases:

- Phase 1 : reservoir characteristics understanding, which includes (but not limited to): understanding the faults characteristics, understanding the hydrocarbon potential per area per formation, and understand the reservoir drive mechanism
- Phase 2 : IOR scenarios development, which setting some possible development scenarios to achieve the study objective. The main parts are trying to understand the need of gas injection, the possible surface facility concept development and well placement strategy
- Phase 3 : economics evaluation, which trying to compare all scenarios from the economics perspectives.

a. IOR scenarios premise

		Improved Oil Recovery Development Scenarios								
Scenario	**Reference Case**	**Scenario 1 (Statoil 6 Wells)**	**Scenario 1A (Statoil 6 Wells)**	**Scenario 1B (Statoil 6 Wells)**	**Scenario 2 (6 Wells - modified)**	**Scenario 2 A (6 Wells - modified)**	**Scenario 2 B (6 Wells - modified)**	**Scenario 3 (10 Wells)**	**Platform Case**	**No Gas Injection Case**
Simulation Name	Reference Case	GFS Restart	GFS Restart1	Extended Case	GFS Restart Mod 2	GFS Restart Mod 3	Extended Mod 7	Extended Case 9	GFS Restart Platform	GFS Restart No Injection
Facilities	Subsea	Subsea	Subsea	Subsea	Subsea	Subsea	Subsea	Subsea	Platform	Subsea
New Producing Wells	--	4	4	4	4	4	4	5	4	4
New Gas Injectors	--	2	2	2	2	2	2	5	2	--
Gas Injection Rate, MSM^3	--	2.4	2.4	2.4	2.4	2.4	2.4	3.75	2.4	--
Peak Oil Rate, SM^3/day	4000	4000	4000	3600	4000	4000	3600	3400	4200	3950
Peak Water Rate, SM^3/day	1480	1420	1420	1220	1440	1480	1220	920	1480	1960
Cum. Oil Production, MSM^3	7.91	11.91	12.26	9.65	11.70	12.32	9.80	12.08	12.03	9.76
Cum. Net Gas production, BSM^3	8.10	10.18	11.0	8.85	10.10		9.75	8.29	11.97	10.49
Recovery Factor, %	18.75	28.23	29.43	22.86	27.82	29.19	23.16	28.60	28.51	23.12
Reservoir Pressure at 2030, bara	200	125	130	210	125	165	170	165	110	150 (production stop at 2023)
Premise	Do Nothing	Statoil Initial Plan	Statoil Initial Plan and activating the existing well G-1H	Statoil Initial Plan, with setting transmissibility across faults to zero	Modified trajectory of 2 wells (from Scenario 1 - Statoil Initial Plan): W1 and GI-4	Scenario 2 B and activating the existing well G-1H	Scenario 2, with setting transmissibility across faults to zero	Statoil Initial Plan, with setting transmissibility across all faults to zero, and adding 4 wells to achieve the same level of oil recovery	Statoil Initial Plan (Scenario 1), with using Wellhead platform as surface facility drill centre (increase well efficiency to 95% and reduce minimum THP to 60 bar)	Statoil Initial Plan (Scenario 1), without adding new gas injectors wells

Table 3 Summary of IOR development Scenarios

IOR development scenarios brief descriptions

Reference Case

This is Statoil history matched model; continue producing up to 1 January 2030 without addition of new wells. The main purpose for this model is to be used as a basis for developing further IOR project scenarios. The oil production history is quite matched with the model but there is some further tuning required to smoothly matching the water production history. The ultimate oil recovery factor (up to 1 January 2030) for this case is 18.75% and in which the reservoir pressure is around 200 bara at the time.

Scenario 1 (GFS RESTART)

Scenario-1 is the Statoil initial development plan to obtain 10% additional oil recovery by adding four producers and two injectors, which effectively start on 1 October 2015. Table 4 shows the remaining oil in place area by area for this scenario. In addition, to see the impact of gas injection on the recovery, simulation with no gas injection was run and the result shows that Statoil IOR project with no gas injection is feasible, but cannot achieve 10% additional oil recovery as the target. The Statoil scenario-1 simulation is based on subsea wellhead head facility and in order to see the effect of oil recovery with the platform, sensitivity was made by reducing minimum tubing head pressure to 60 bara and 10 bara and increasing well efficiency to 95%. The platform case gave increased recovery than the subsea case as shown in the table 5.

		Scenario 1 (Remaining OIP)			
Segment	FIPNUM	NANSEN (MSm3)	EIRIKSEN (MSm3)	RAUDE (MSm3)	TOTAL REMAINING OIP (MSm3)
A1	70	1,279	0,230	0,000	1,509
A2	60	2,199	3,394	0,726	6,319
A3	30	2,518	4,052	0,477	7,047
A4	20+10	1,973	1,993	0,384	4,350
A5	120+130	4,953	2,750	0,705	8,408
A6	140+150	2,129	0,363	0,000	2,492
					30,125

Table 4 Remaining Oil in place for GFS RESTART (scenario 1)

Case	Minimum Tubing Head Pressure (bar)	Remaining Oil In Place (MSM^3)	Oil Recovery (MSM^3)
GFS Restart	90	30.290	11.910
GFS Restart Plt	60	30.174	12.026
GFS Restart Plt 1	10	30.149	12.051

Table 5 Sensitivity of minimum tubing head pressure vs oil recovery

Scenario 1A (GFS RESTART 1)

In the model we found that in the area A3, remaining oil can also be drained by activating the well G-1H (this can be seen from table 4 that the oil in place in the area is potentially big). This scenario is modified from scenario 1, by only activating the existing well G-1H. As the result, the oil recovery factor is increased by 1.2 % with an increment of 0.35 M SM^3 oil and 0.82 B SM^3 gas cumulative productions, compare to scenario 1.

Scenario 1B (Extended Case)

The worst reservoir condition needs to be considered, and the impact should be part of the considerations on the IOR project. The worst reservoir conditions that we considered here is by setting the transmissibility across all faults to zero (scenario 1 reservoir model as a basis). The result on the oil recovery can be seen from table 6, in which a loss of around 2.249 M SM^3 oil (compared to scenario 1) with oil recovery factor reduction down to 22.86 %. Table 7 shows the increment of remaining oil in place in different segments for this case compared to the scenario 1, where the most affected areas are A3, A4 (Nansen) and A4 (Eiriksen).

		Scenario 1B (Remaining OIP)			
Segment	FIPNUM	NANSEN (MSm3)	EIRIKSEN (MSm3)	RAUDE (MSm3)	TOTAL REMAINING OIP (MSm3)
A1	70	1,159	0,260	0,000	1,419
A2	60	2,491	3,653	0,726	6,870
A3	30	3,055	4,221	0,495	7,771
A4	20+10	2,294	2,558	0,390	5,242
A5	120+130	5,194	2,834	0,670	8,698
A6	140+150	2,133	0,241	0,000	2,374
					32,553

Table 6 Remaining Oil in place for extended case (fault transmissibility = 0)

		Increment in Remaining OIP for EXTENDED CASE vs GFS_RESTART			
Segment	FIPNUM	NANSEN (MSm3)	EIRIKSEN (MSm3)	RAUDE (MSm3)	TOTAL REMAINING OIP (MSm3)
A1	70	-0,120	0,030	0,000	-0,090
A2	60	0,292	0,259	0,000	0,551
A3	30	0,537	0,169	0,018	0,724
A4	20+10	0,321	0,565	0,006	0,892
A5	120+130	0,241	0,084	-0,035	0,290
A6	140+150	0,004	-0,122	0,000	-0,118
					2,249

Table 7 Increment in Remaining OIP for scenario 1B (compared to scenario 1 as a basis)

Scenario 2 (GFS RESTART MOD 2)

In this scenario, the well trajectories of two wells (W1 and GI-4) of scenario-1 are modified in order to reduce the oil recovery risk in case of worst reservoir conditions (zero fault transmissibility). For the normal reservoir conditions, this scenario gives 0.41% less recovery than scenario 1 (table 3), but for the worst reservoir conditions, this scenario will reduce the reduction of oil recovery. Figure 14 shows the trajectory of the modified wells. Initially the W1 was draining from layer 1-14 (not covering A3 – Nansen, in case of no transmissibility across fault between A2 and A3), in which in this scenario, we modified the location and penetration to only layers 1-8, in order to extend the draining capability of A3 – Nansen formation. GI-4 well location and well penetration (to layers 1-12 instead of layers 1-14) are also modified, in order to have effective pressure support in draining A1 – Nansen, in case of no transmissibility across A1 and A2.

Scenario 2A (GFS RESTART MOD 3)

This scenario is having the same basis as scenario 2, with the only change on activating the existing well G-1H. The result shows an increment in oil recovery factor by 1.37 % (compare to scenario 2).

Scenario 2B (EXTENDED MOD 7)

This scenario is also having the same basis as scenario 2A, with changing the transmissibility across all faults to zero (in case of worst reservoir conditions). It has been observed from the results that if the worst reservoir conditions exist, this scenario reduces the recovery risk of 0.3%.

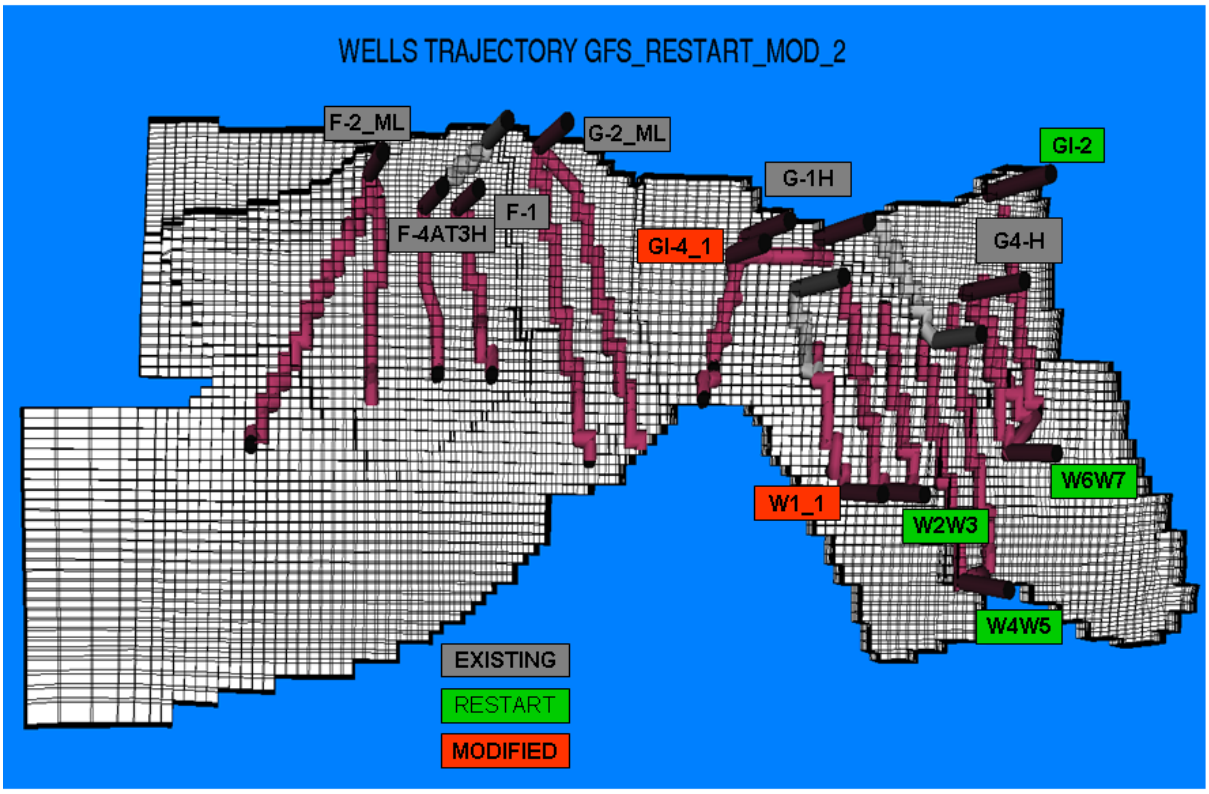


Figure 14 Well trajectory of Scenario 2 Improved Oil Recovery

Scenario 3 (EXTENDED CASE 9)

After setting the transmissibility across all faults to zero, the ultimate oil recovery was decreased to 22.86 %. To achieve 10% additional oil recovery as the initial objective, we were supposed to increase number of wells as necessary. It is observed that A2, A3, A4 and A5 were the most affected areas in worst case conditions. Several simulations with different number of wells, different well locations, trajectories, gas injection rate, maximum production rate, etc were made and at last, it is concluded that by adding one producer (A31_2) in A3 area and three injectors (AI12_3, AI34_3 & AI5) in A1-2, A3-4 and A5 areas respectively (table 8), it can achieve 28.60% oil recovery factor. Table 9 shows the total remaining oil in place for this scenario, which is almost the same as of scenario 1. The sensitivity on gas injection (table 10) for the scenario-3 was also performed and at least 3.75 MSM^3 is needed to achieve the target. The wells trajectory profile has been created using ECLPOST and is shown in figure 15.

New wells location			
Well Type	Well Name	Area	Zone
Production	A31	3	Nansen
Injection	AI12_3	1, 2	Nansen
	AI34_3	3, 4	Nansen
	AI5	5	Nansen

Table 8 New proposed well location for scenario 3

		Scenario 3, Extended Case 9 (Remaining OIP)		
Segment	FIPNUM	NANSEN (MSm3)	EIRIKSEN (MSm3)	TOTAL REMAINING OIP (MSm3)
A1	70	1,012	0,258	1,270
A2	60	2,337	3,385	6,450
A3	30	2,161	3,574	6,210
A4	20+10	2,174	2,571	5,141
A5	120+130	5,000	2,855	8,522
A6	140+150	2,138	0,198	2,373
				30,132

Table 9 Remaining OIP for Scenario 3 (Extended Case 9)

Case	Gas Injection Rate (MSM^3)	Remaining Oil In Place (MSM^3)	Oil Recovery (MSM^3)
Extended Case 5	2.4	31.314	10.886
Extended Case 6	3	30.945	11.255
Extended Case 8	3.5	30.309	11.891
Extended Case 9	3.75	30.132	12.068
Extended Case 10	4	30.037	12.163
Extended Case 11	4.5	29.772	12.428

Table 10 Sensitivity of gas injection vs oil recovery

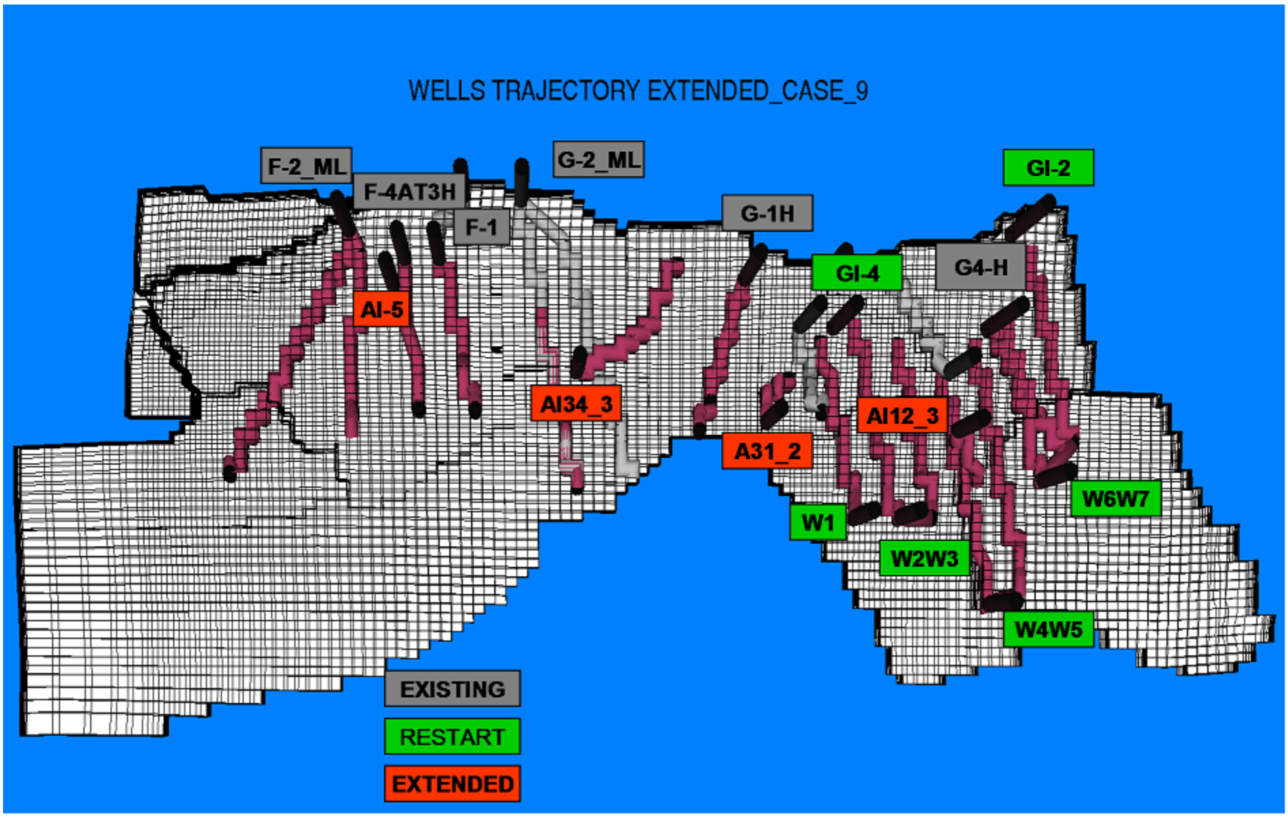


Figure 15 Wells trajectory of scenario 3

b. Well by well productivity

The IOR project needs some new wells to be drilled. These new wells should be assessed the productivity, on how much cumulative oil produced and the impact on the existing wells.

Below is the table summarized the cumulative oil produced from each wells up to 1 January 2030.

	Well Cummulative Oil Production 1 Oct 2015 onwards (MSM^3)										
	F-4AT3H	G-1H	G-2_ML	F-2_ML	G-4H	F-1	W1	W2W3	W4W5	W6W7	A31
Reference Case	0.346		0.592	0.413	0.344	0.708					
GFS_Restart	0.253		0.427	0.324	0.269	0.536	1.039	1.275	1.166	1.111	
GFS_Restart No Inj	0.164		0.277	0.215	0.279	0.377	0.735	0.763	0.707	0.730	
GFS_Restart Platform	0.246		0.420	0.314	0.275	0.523	1.060	1.277	1.297	1.106	
Extended Case 9	0.290	0.951	0.000	0.209	0.232	0.386	1.140	1.311	1.250	1.028	0.703
Extended Case	0.257	0.000	0.000	0.140	0.206	0.287	0.926	1.156	1.150	0.957	

Table 11 Well by well cumulative oil production

From the table above, it can be seen that all the new wells (producers) are producing quite much of oil, and the existing wells oil cumulative production are not reduced so much. So, it can be concluded that all the new producers' wells are economically balanced / viable.

IV. Economics Evaluation

a. Economics Assumptions

Economics assumptions:

- The economic calculation is based on **increment** to reference case (do nothing case)
- Exchange rate is assumed to be constant 1 USD = 6.28 NOK
- Base case for discount rate is 5%
- Inflation rate is 1 %
- Net Present Value (NPV) is calculated to the year of 2010
- Oil price is forecasted to be 400 NOK / barrel on 2010 and for the base case, the price increases at constant level 3% every year
- Gas price is forecasted to be 200 NOK / BOE on 2010, and for the base case, the price increases at constant level of 3% every year. Gas heating value is assumed to be 1 Mscf = 1 MMBTU
- Capital Expenditures (CAPEX) assumptions:
  - Wellhead platform costs 11 000 MNOK. Cost phasing is assumed to be distributed in 4 years: 10% - 30% - 40% - 20%
  - Subsea facility (manifolds + control system) cost 1 500 MNOK (with additional 1 000 MNOK for next additional facility). Cost phasing is assumed to be distributed in 3 years: 20% - 40% - 40%
  - Drilling one well from platform costs 300 MNOK, with assumption using jack up drilling rig
  - Drilling one subsea well costs 300 MNOK, with assumption using jack up drilling rig
  - Abandonment cost for 1 platform is 400 MNOK (including wells P&A)
  - Abandonment cost for 1 subsea facility is 200 MNOK (including well P&A)
- Operational Expenditures (OPEX) assumptions:
  - Increment of the operating cost for additional drilling platform is 61 NOK / BOE
  - Increment of the operating cost for additional subsea facilities is 111 NOK / BOE
- Sensitivity analysis (to cover uncertainties)
  - Oil recovery +/- 30%
  - Gas recovery +/- 30%
  - Oil / gas price (yearly changes +5% / -2%)
  - CAPEX +/- 40%
  - OPEX +/- 15%
  - Discount rate +20% -10%

b. IOR Economics Analysis

Below is the summary table of the economics evaluation of some IOR scenarios:

<table>
<tr><th rowspan="3">Economic Parameters (Increment)</th><th colspan="6">Extended Case (Additional 6 wells, 4 producers + 2 injectors)</th><th>No Injection</th></tr>
<tr><th colspan="3">Platform</th><th colspan="3">Subsea</th><th rowspan="2">Subsea (Base Case)</th></tr>
<tr><th>High Case</th><th>Base Case</th><th>Low Case</th><th>High Case</th><th>Base Case</th><th>Low Case</th></tr>
<tr><td>NPV (2010) - MNOK</td><td>11,915.45</td><td>25.39</td><td>-9,794.27</td><td>11,569.40</td><td>5,199.22</td><td>175.54</td><td>1,189.13</td></tr>
<tr><td>IRR</td><td>28.96%</td><td>5.05%</td><td>--</td><td>102.59%</td><td>41.86%</td><td>7.25%</td><td>64.06%</td></tr>
</table>

Table 12 Economics (Platform vs Subsea with gas injection vs Subsea with no gas injection)

Economic Parameters (Increment)	Extended Case (Transmissibility Across Faults are set to zero)		
	Subsea (Additional 10 Wells, 5 producers + 5 injectors)		
	High Case	**Base Case**	Low Case
NPV (2010) - MNOK	7,270.84	**335.35**	-5,231.60
IRR	17.90%	**5.74%**	--

Table 13 Economics of the Subsea case development with additional 10 wells (Scenario 3)

- Subsea development concept is preferable than platform, as it still gives positive NPV even for the extreme low case (of all economic parameters) condition. It gives less project failures risks.
- Subsea development with gas injection increases field economics value higher than no gas injection scenario. No gas injection scenario gives higher internal rate of return (IRR), which means higher capital productivity, due to less capital spending, but lower income ratio reduction to capital ratio reduction.
- Subsea development for the worst case reservoir condition scenario (by setting the transmissibility across all faults to zero), still gives barely positive NPV (IRR slightly above 5%), with the premise to achieve the same level of oil recovery (10% additional recovery), by adding 4 wells (3 injectors and 1 producer)

Below is the result of the sensitivity analysis of the IOR development scenarios:

		Platform			Subsea		
		High	Base	Low	High	Base	Low
Oil recovery	% Sensitivity	30 %	0 %	-30 %	30 %	0 %	-30 %
	% NPV (2010)	9105,32 %	0,00 %	-9105,32 %	38,42 %	0,00 %	-38,42 %
Gas recovery	% Sensitivity	30 %	0 %	-30 %	30 %	0 %	-30 %
	% NPV (2010)	3671,41 %	0,00 %	-5781,13 %	6,91 %	0,00 %	-7,42 %
Oil price	% Sensitivity	26 %	0 %	-26 %	26 %	0 %	-26 %
	% NPV (2010)	6247,19 %	0,00 %	-11720,40 %	29,39 %	0,00 %	-55,45 %
Gas price	% Sensitivity	26 %	0 %	-26 %	26 %	0 %	-26 %
	% NPV (2010)	3723,84 %	0,00 %	-6581,37 %	7,61 %	0,00 %	-15,72 %
CAPEX	% Sensitivity	40 %	0 %	-40 %	40 %	0 %	-40 %
	% NPV (2010)	-16995,64 %	0,00 %	16995,64 %	-21,11 %	0,00 %	21,11 %
OPEX	% Sensitivity	15 %	0 %	-15 %	15 %	0 %	-15 %
	% NPV (2010)	-1148,02 %	0,00 %	1148,02 %	-8,19 %	0,00 %	8,19 %
Discount rate	% Sensitivity	20 %	0 %	-10 %	20 %	0 %	-10 %
	% NPV (2010)	-2003,43 %	0,00 %	1116,17 %	-9,49 %	0,00 %	5,11 %

Table 14 Sensitivity analysis for platform and subsea scenario 1 case

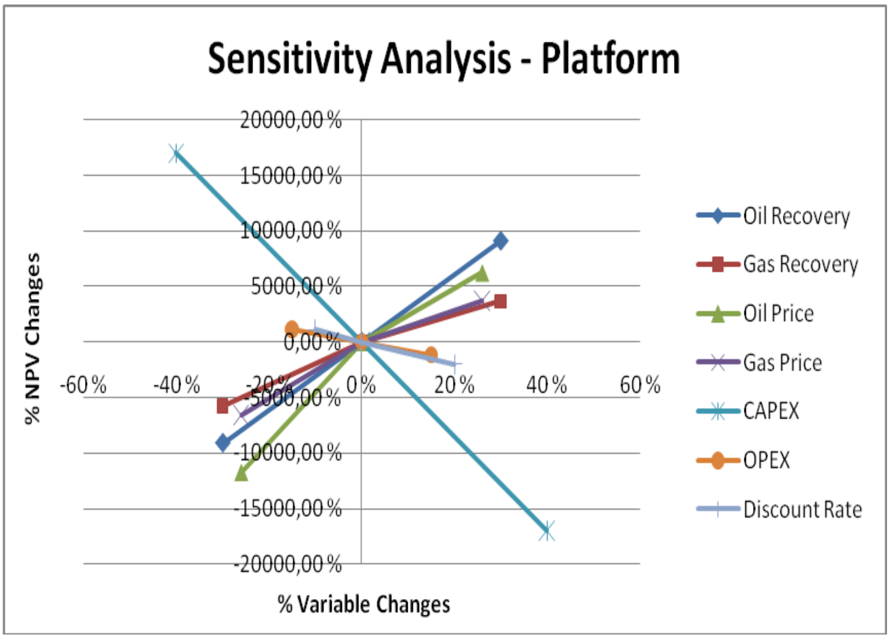


Figure 16 Platform case sensitivity analysis

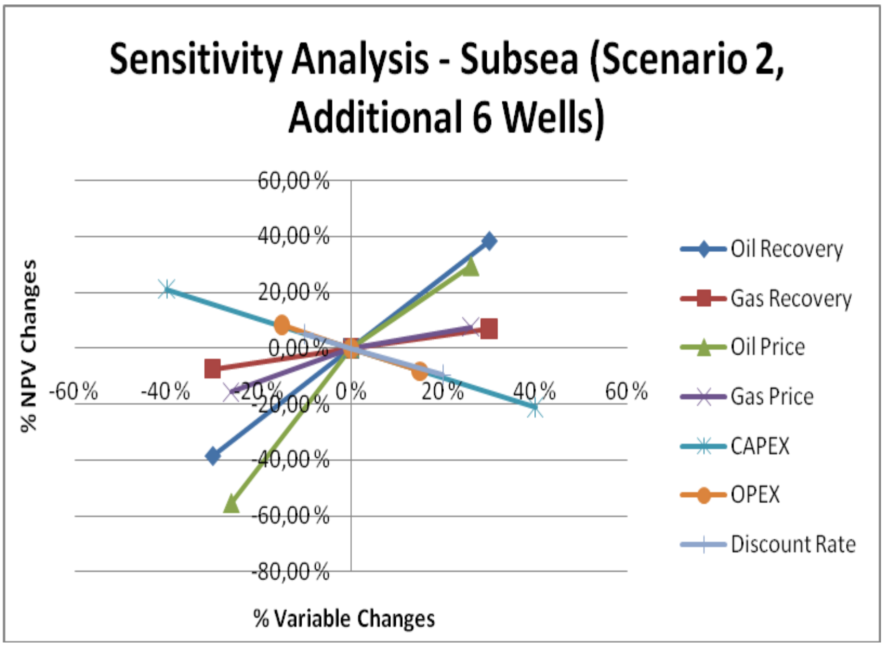


Figure 17 Subsea development (Scenario 1 and 2) Sensitivity Analysis

- This above chart is valid for Scenario 1 and Scenario 2, as both of the scenarios have almost the same economics profile (minor differences on the hydrocarbon recovery between both of the cases)
- Subsea development with additional 6 new wells has oil recovery and oil price as the most sensitive parameters.
- Platform development with the additional 6 new wells indicates CAPEX as the most sensitive parameter

		Subsea		
		High	Base	Low
Oil recovery	% Sensitivity	25 %	0 %	-25 %
	% NPV (2010)	347 %	0 %	-347 %
Gas recovery	% Sensitivity	25 %	0 %	-25 %
	% NPV (2010)	48 %	0 %	-91 %
Oil price	% Sensitivity	26 %	0 %	-26 %
	% NPV (2010)	370 %	0 %	-630 %
Gas price	% Sensitivity	26 %	0 %	-26 %
	% NPV (2010)	267 %	0 %	-357 %
CAPEX	% Sensitivity	10 %	0 %	-10 %
	% NPV (2010)	-544 %	0 %	544 %
OPEX	% Sensitivity	15 %	0 %	-15 %
	% NPV (2010)	-52 %	0 %	52 %
Discount rate	% Sensitivity	20 %	0 %	-10 %
	% NPV (2010)	-132 %	0 %	76 %

Table 15 Sensitivity analysis for scenario 3

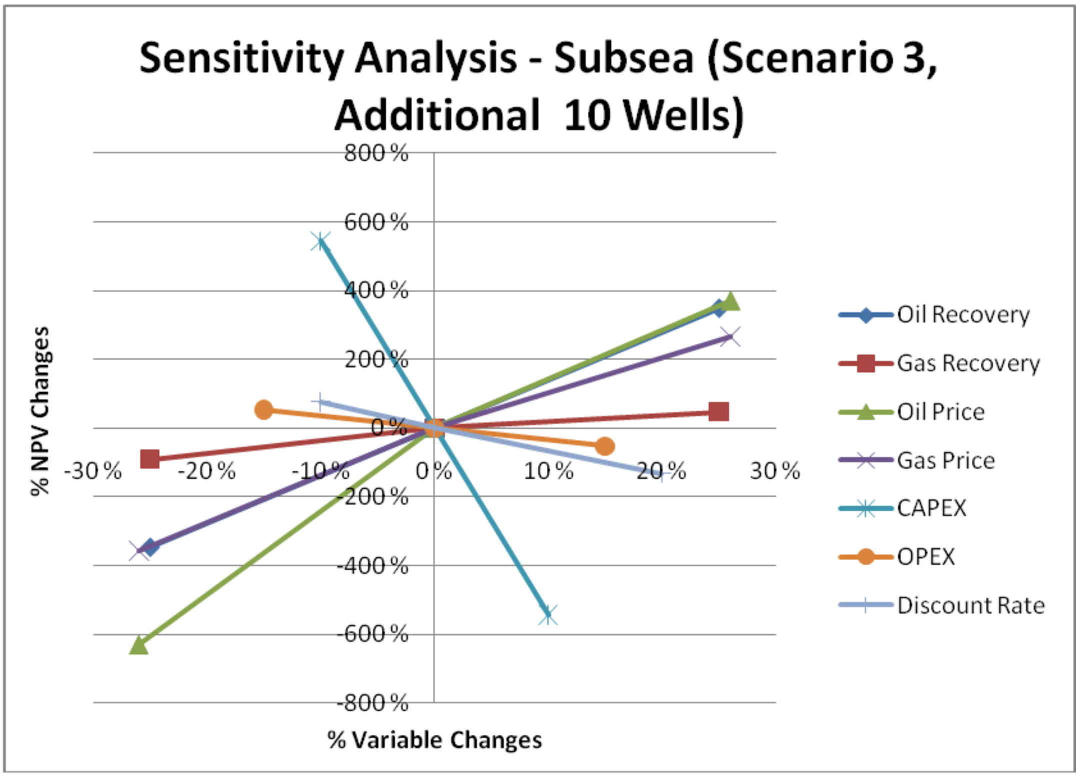


Figure 18 Subsea development (Scenario 3) Sensitivity Analysis

- Subsea development (with 10 wells, worst case reservoir condition, by setting transmissibility across all faults to zero), has CAPEX as the most sensitive parameter. The additional CAPEX spending for drilling new 4 wells (3 injectors and 1 producer), brings CAPEX to the most sensitive parameters, as the CAPEX absolute number increased significantly.

IV. IOR field development decision tree

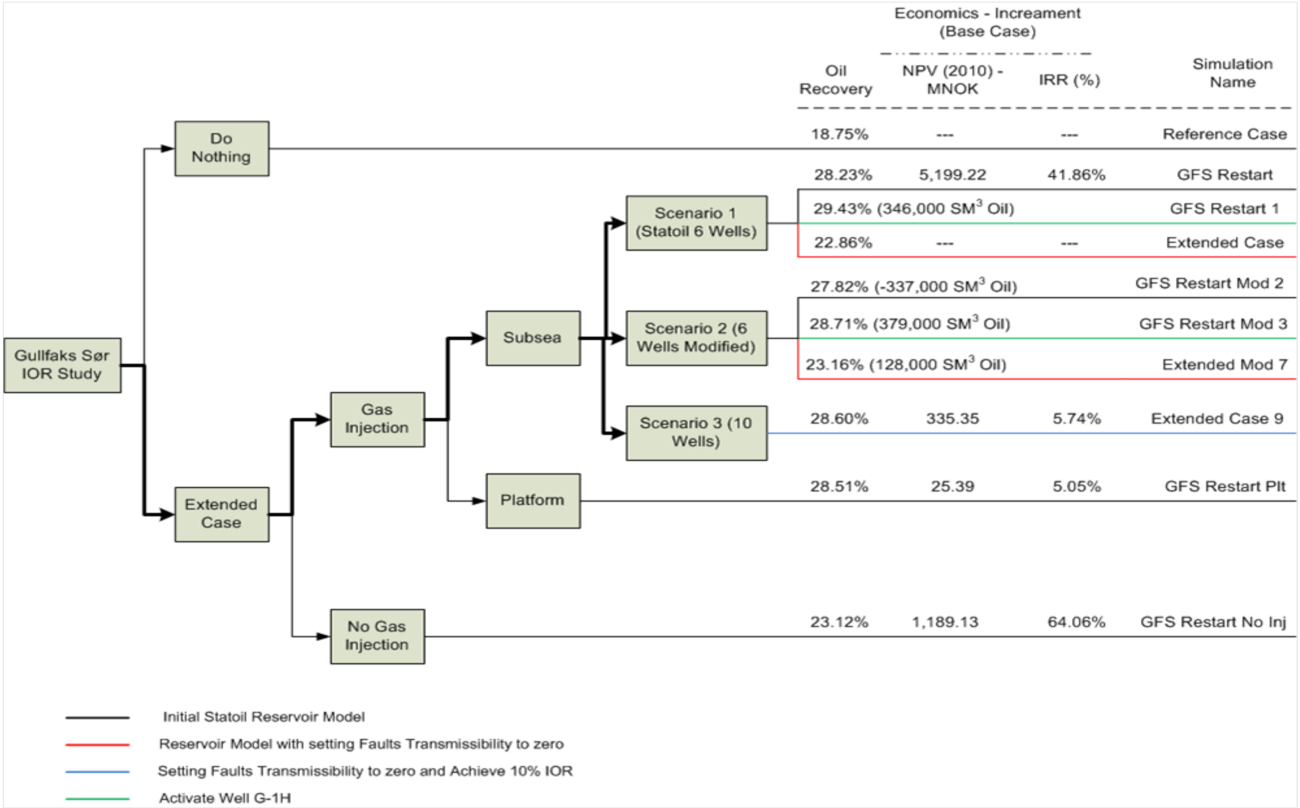


Figure 19 Field development decision tree

- Subsea development with gas injection gives the best economical increment value to the field, compares to the platform development scenario and no gas injection development scenario.
- Worst reservoir condition (by setting transmissibility across all faults to zero), still gives positive NPV value (see red line of scenario 1 and 2). In order to achieve 10% additional oil recovery, need to add 4 wells (3 injectors and 1 producer) in the case of transmissibility across all faults is zero, in which from economical perspective, still give slightly positive NPV compare to 'Do Nothing' case.
- The consideration of choosing scenario 1 or scenario 2 depends on further detailed study on the possibility of worst case reservoir condition versus normal reservoir condition. It also depends on the acceptable business risk profile of Statoil as the operator.
- Activating the existing G-1H well gives oil recovery increment around 0.346 MSM^3 (for scenario-1) and 0.379 MSM^3 (for scenario-2), compares to normal reservoir condition.
- Scenario-2 gives oil recovery increment around 0.128 MSM^3 compares to scenario-1 for worst case reservoir condition. And scenario-2 gives less oil recovery around 0.337 MSM^3 compare to scenario-1 for the normal case reservoir condition.

- Consideration on simulation accuracy (errors, such as numerical error) should be taken into account (further study is recommended, as necessary).

D. Conclusion and Recommendations

- Pressure maintenance (either gas / water injection) is required to achieve additional 10% oil recovery
- Subsea development gives the best increment of field economical value
- The IOR project, is still feasible with the worst case reservoir condition (transmissibility across all faults are zero)
- Modifying wells trajectories of 2 new wells are recommended to reduce the recovery risk in case of worst reservoir condition. Detail probability analysis and simulation accuracy assessment are recommended prior to the decision.
- Activate the existing G-1H well gives higher recovery
- Consider to include the need of upgrading gas injection facilities to 3.75 MSM^3, in case of worst case reservoir condition

E. References

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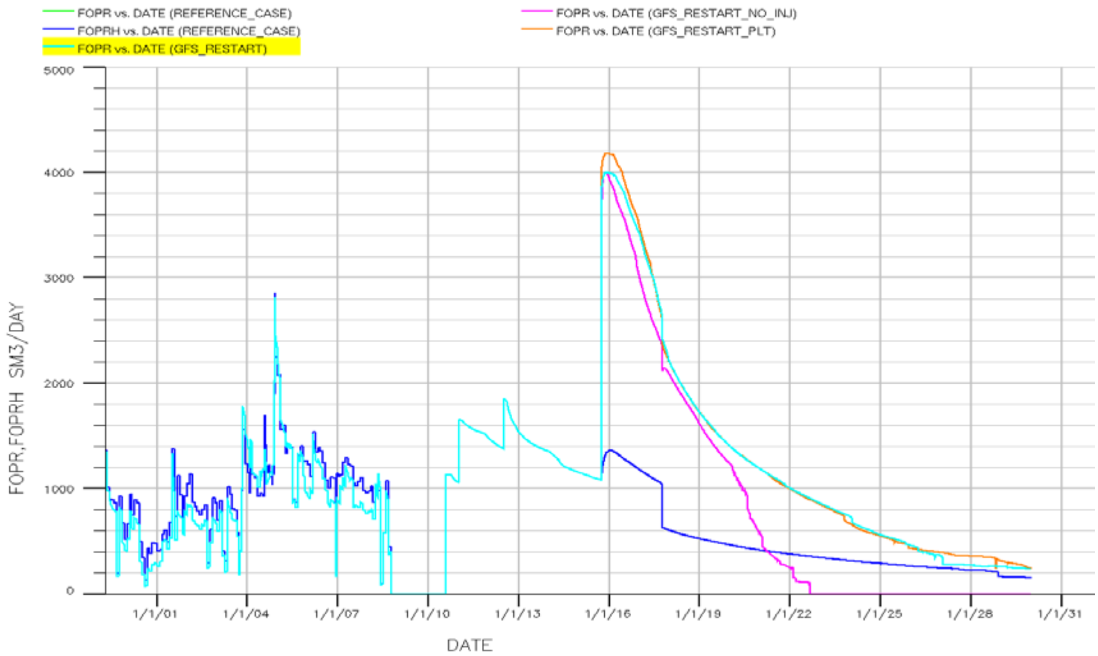
Appendix A: Scenario-1 Statoil Initial Plan Charts

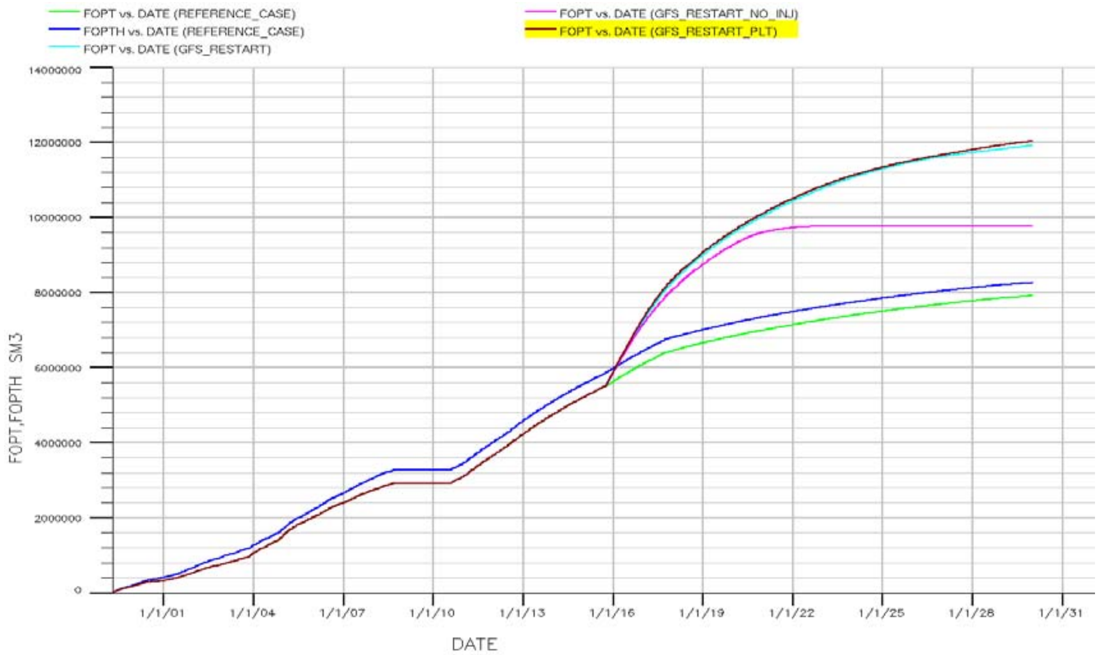
Field Charts

REFERENCE CASE VS GFS_RESTART VS GFS_RESTART_NO_INJ VS GFS_RESTART_PLT

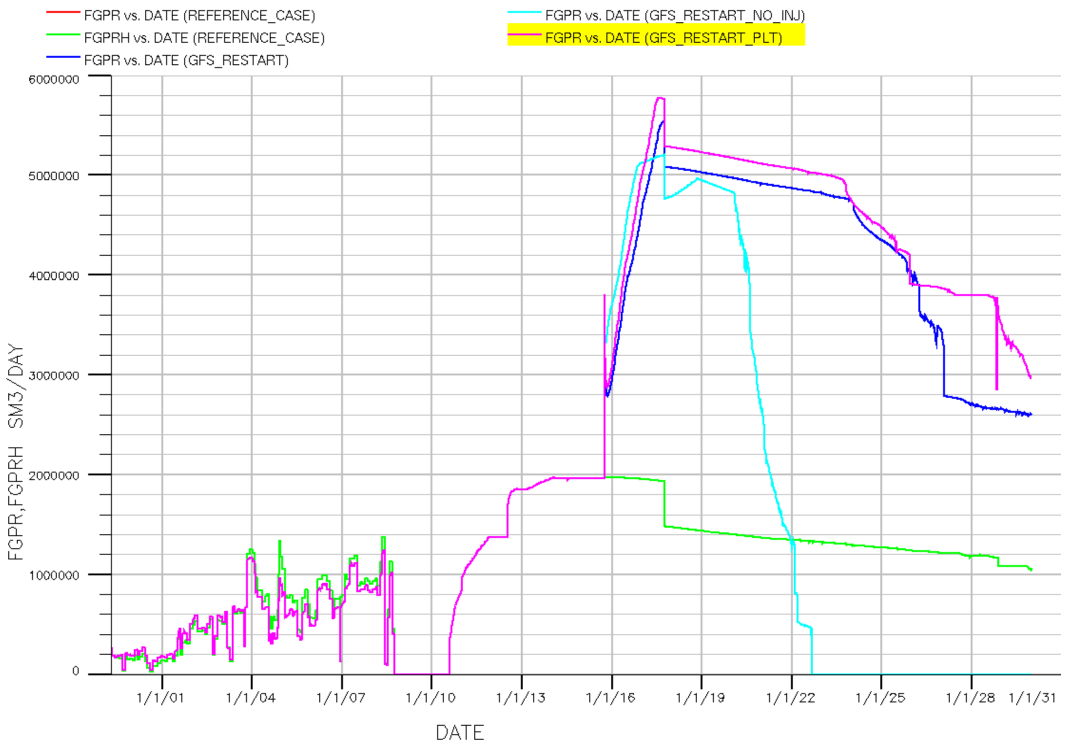
Field Oil Production Rate (FOPR)



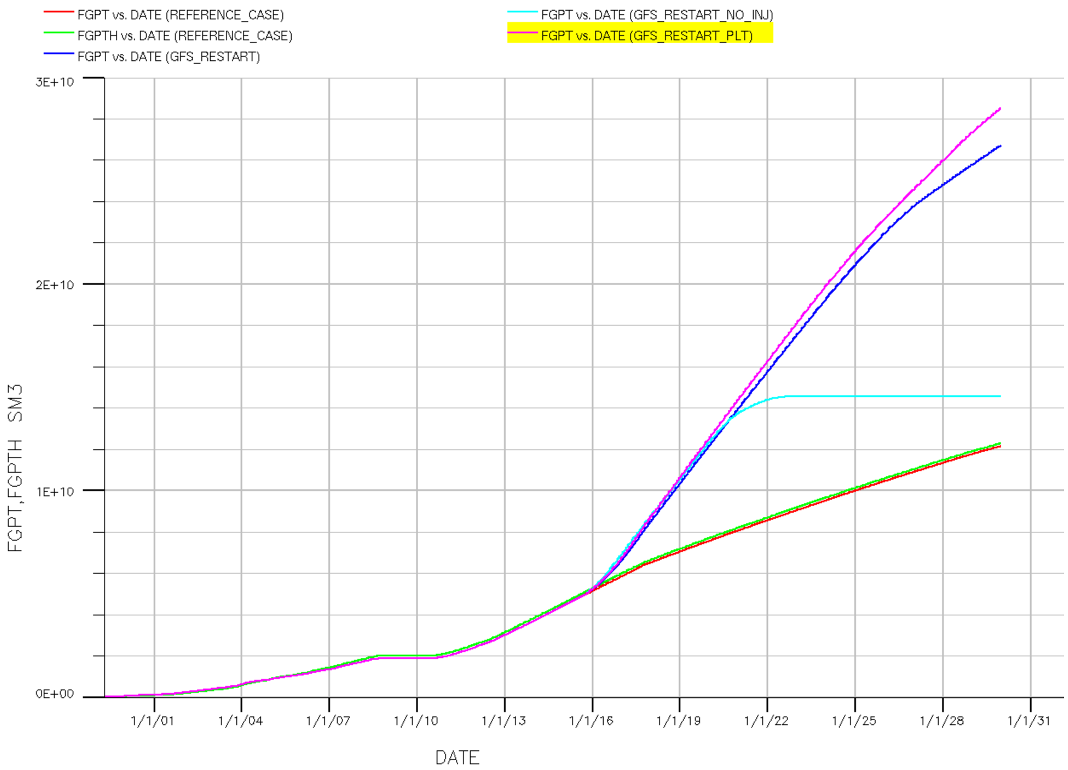
Field Oil Production Total (FOPT)



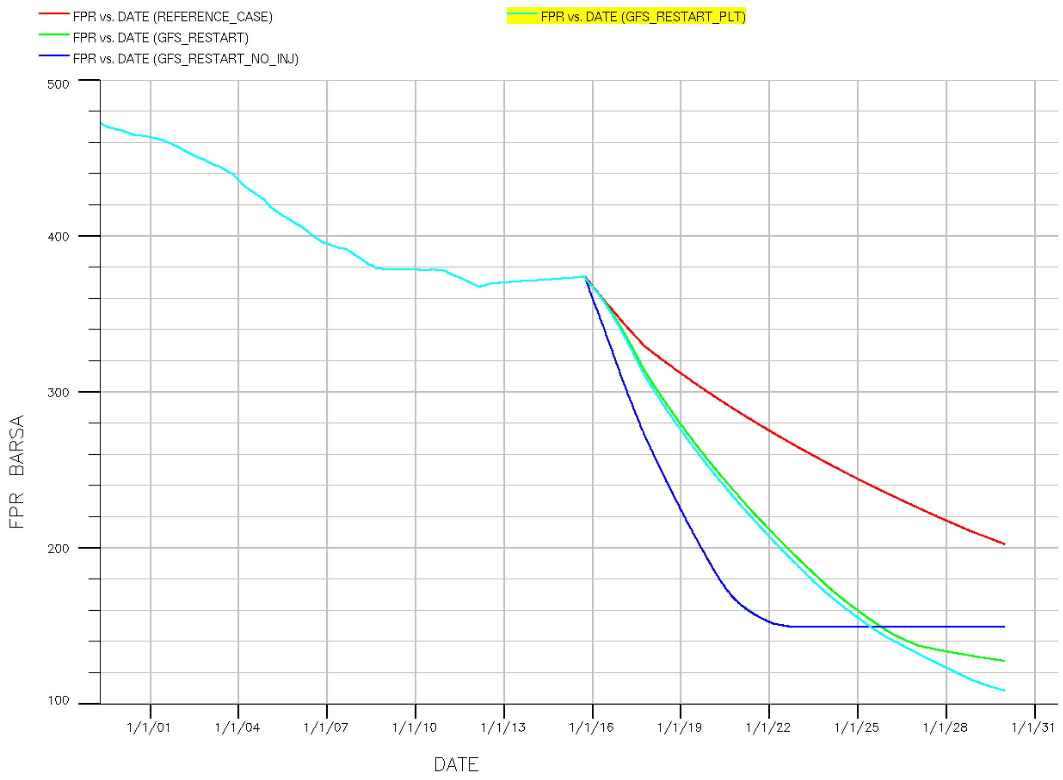
Field Gas Production Rate (FGPR)



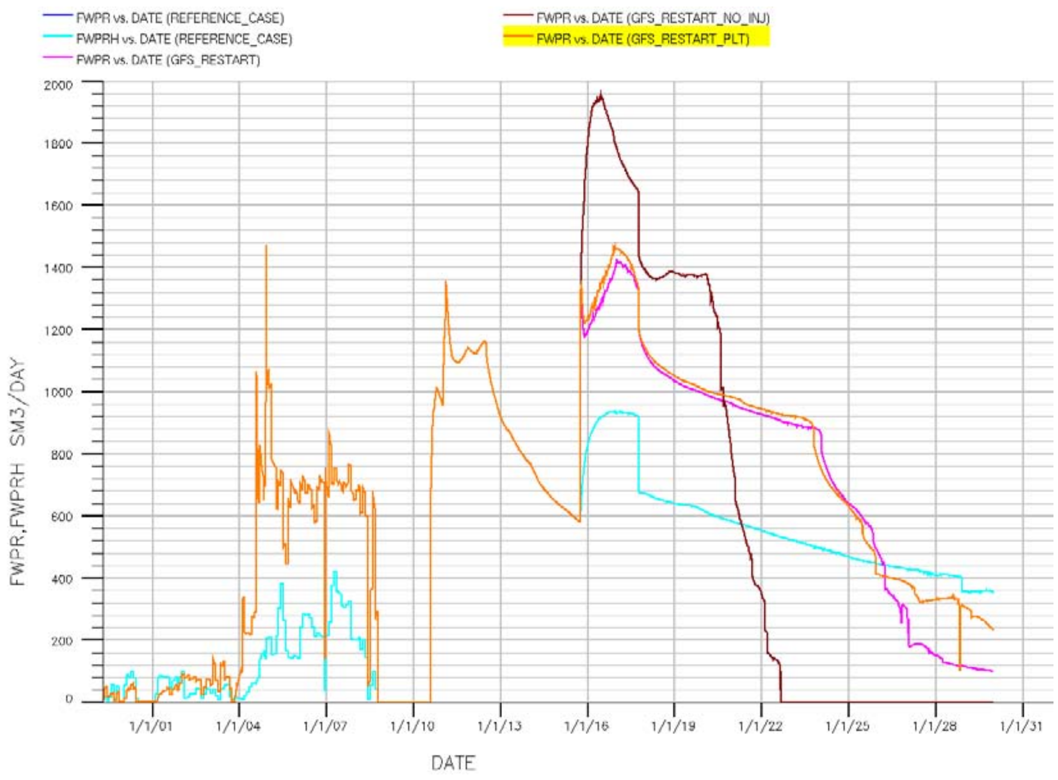
Field Gas Production Total (FGPT)



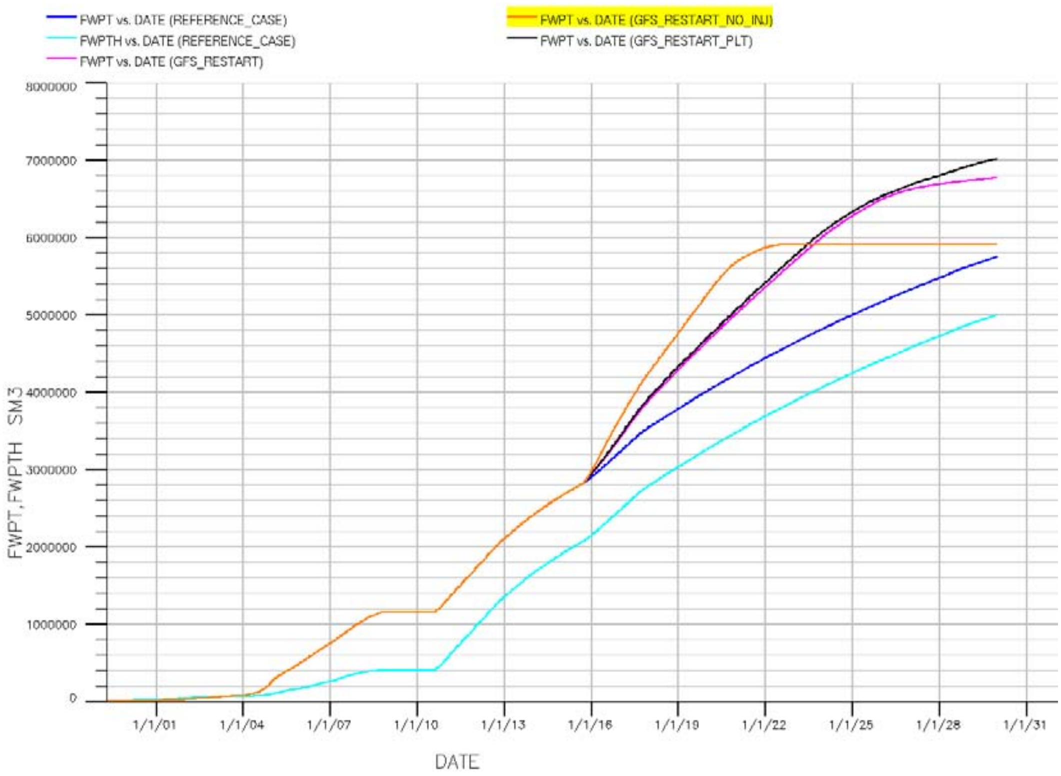
Field Pressure (FPR)



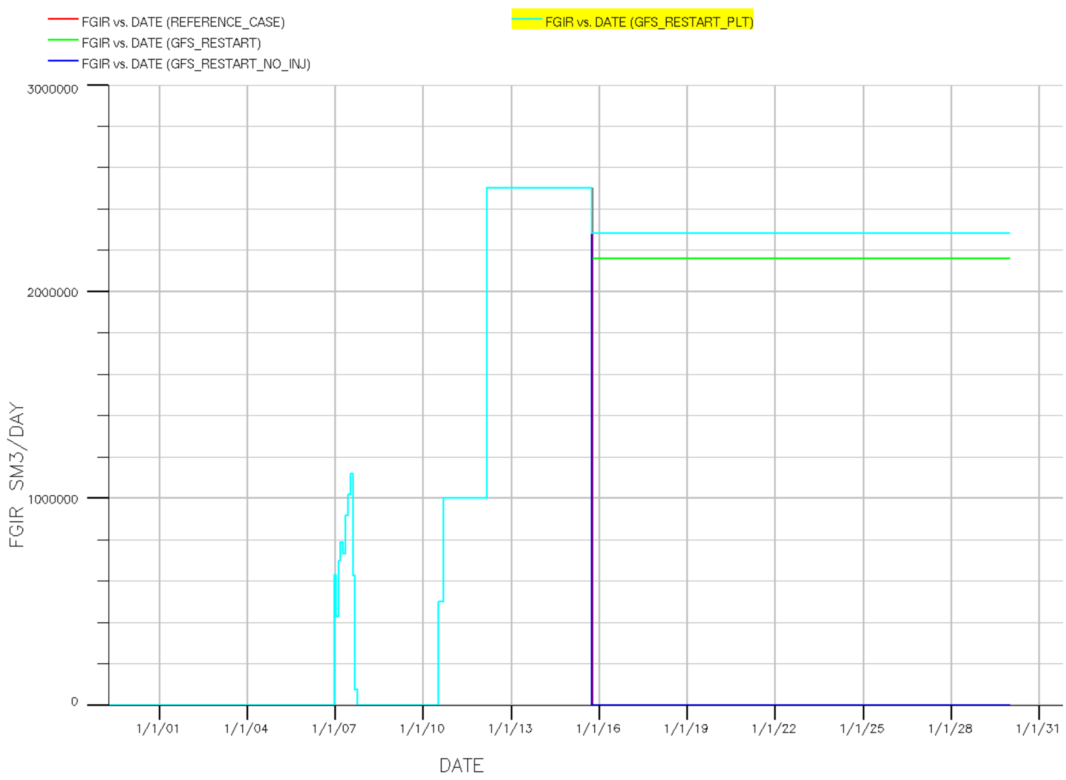
Field Water Production Rate (FWPR)



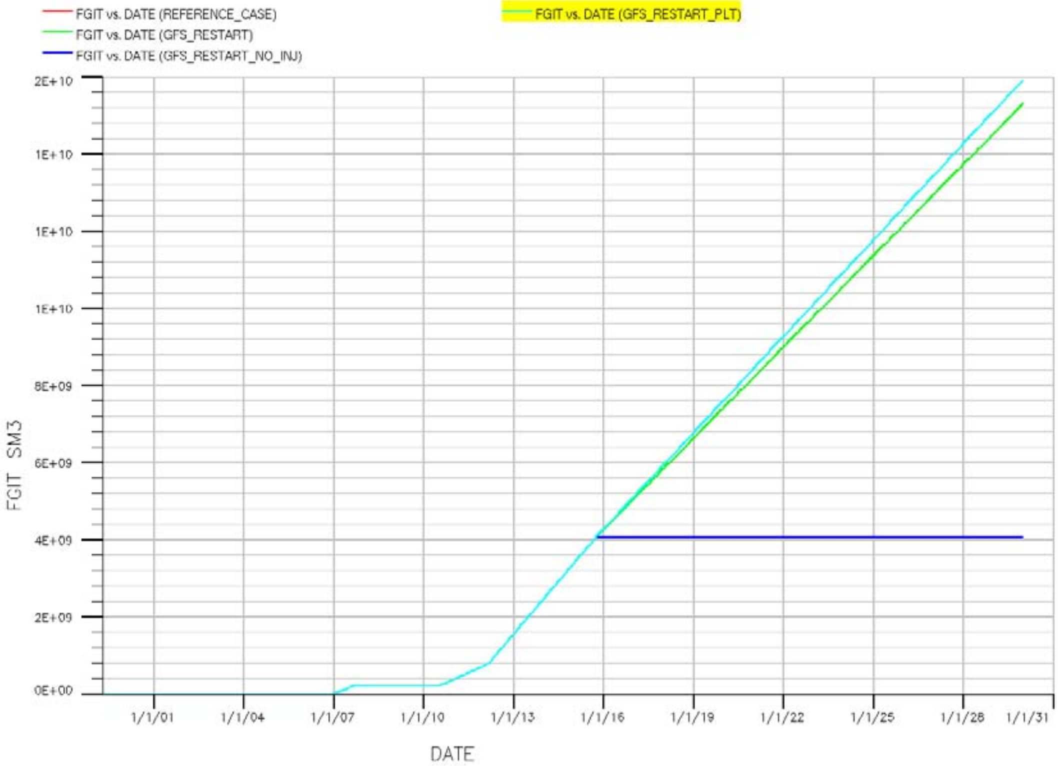
Field Water Production Total



Field Gas Injection Rate (FGIR)



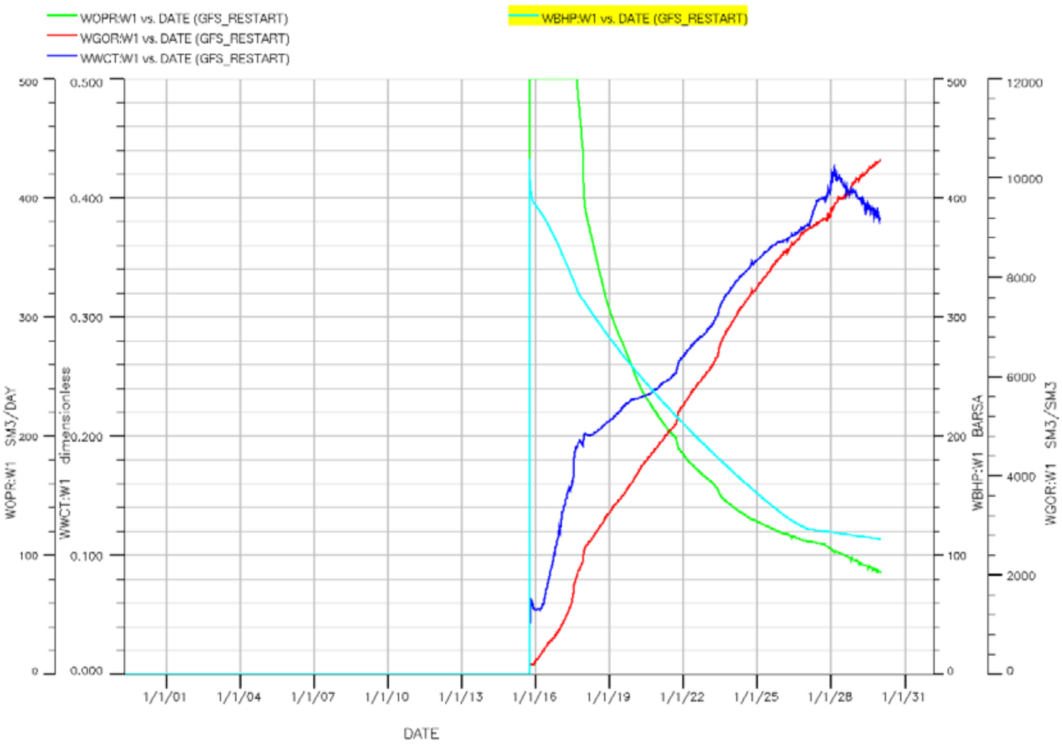
Field Gas Injection Total (FGIT)



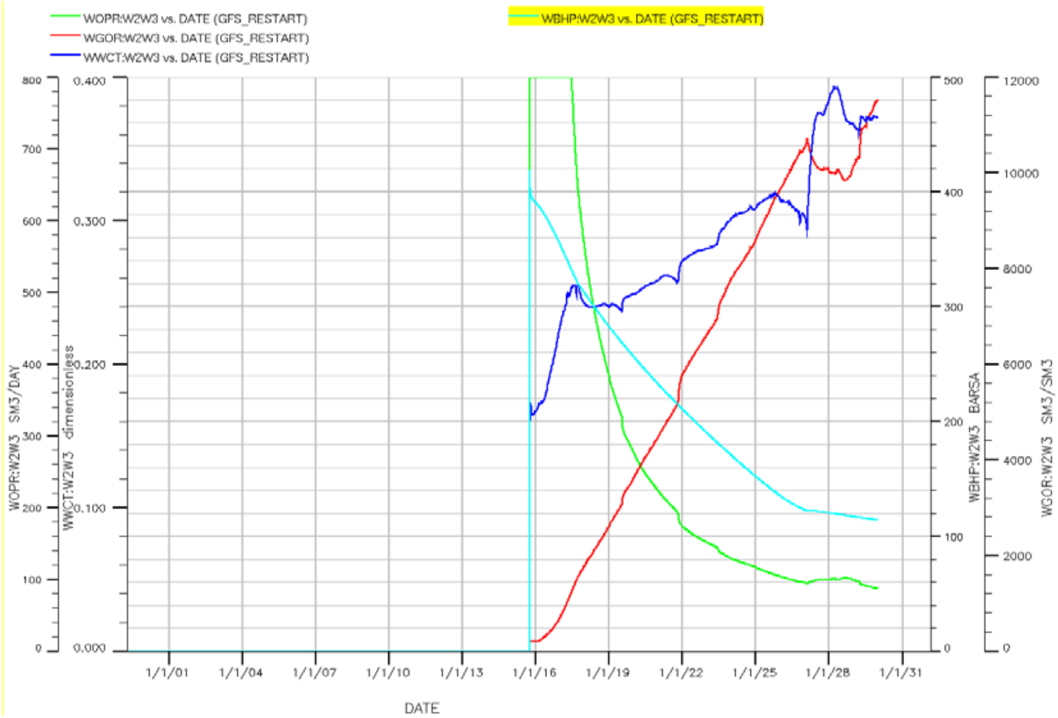
Well Charts

New Proposed Wells

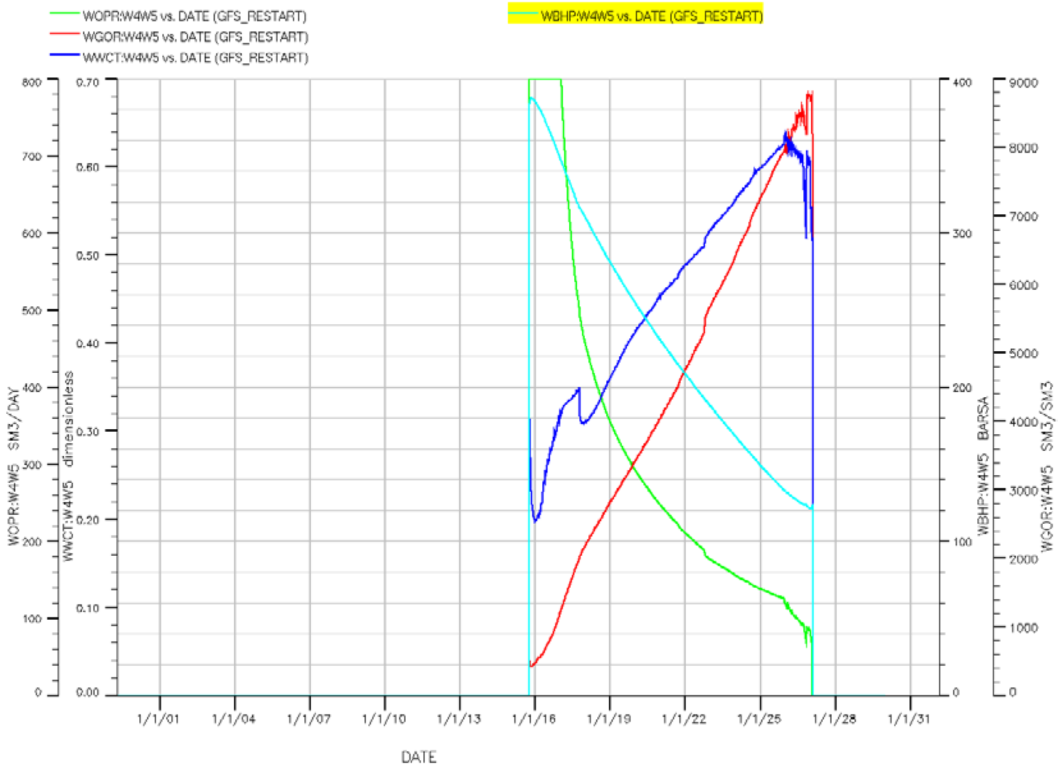
Well W1



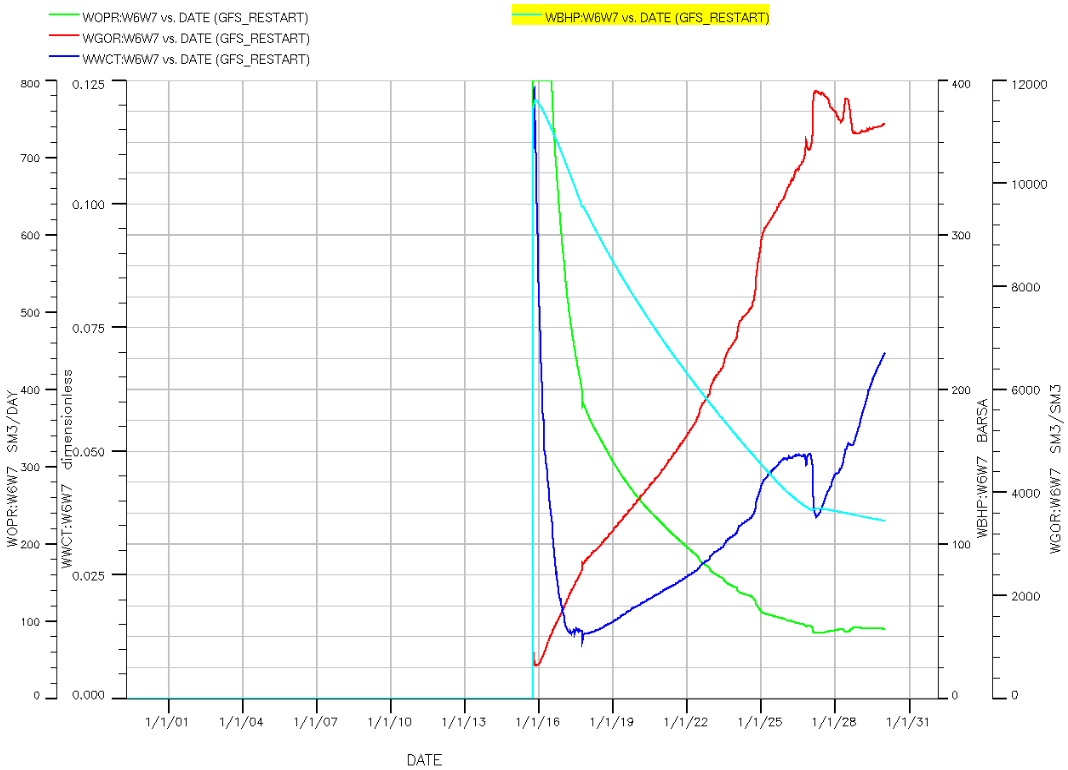
Well W2W3



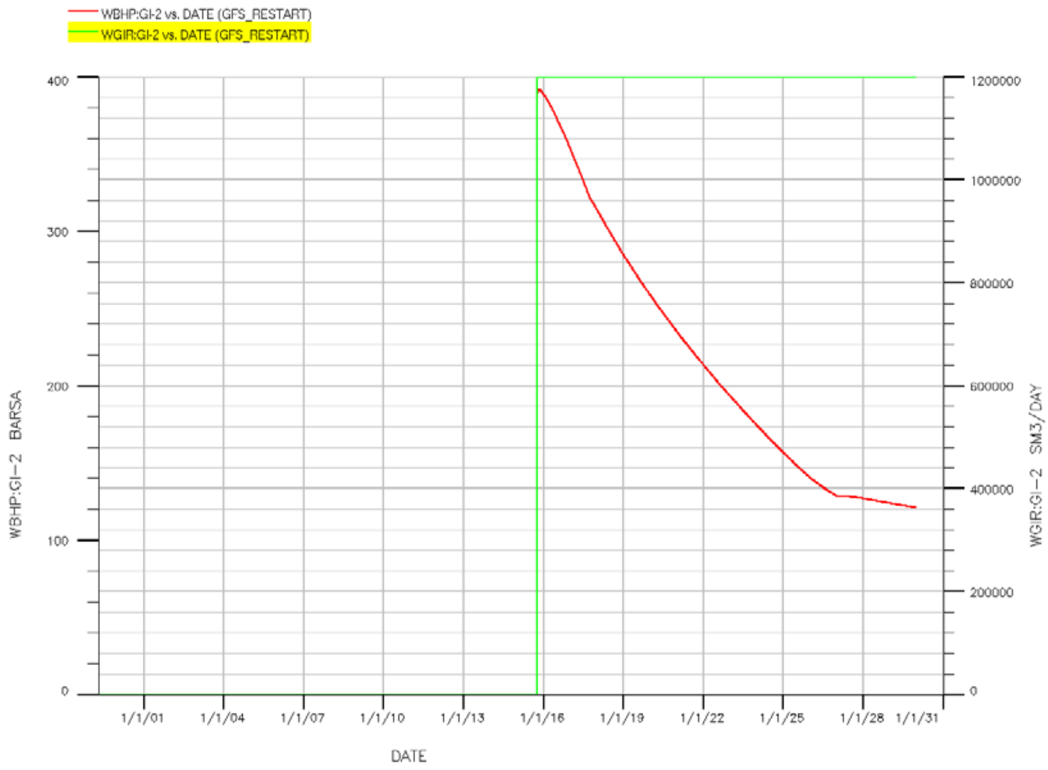
Well W4W5



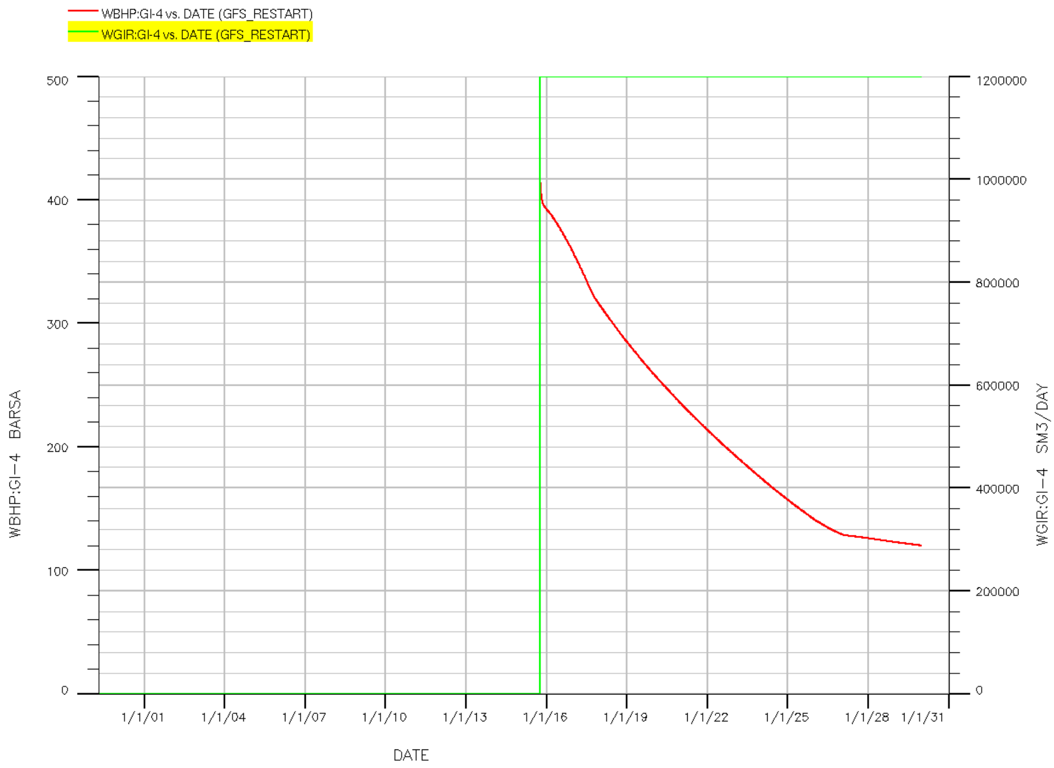
Well W6W7



Well GI-2

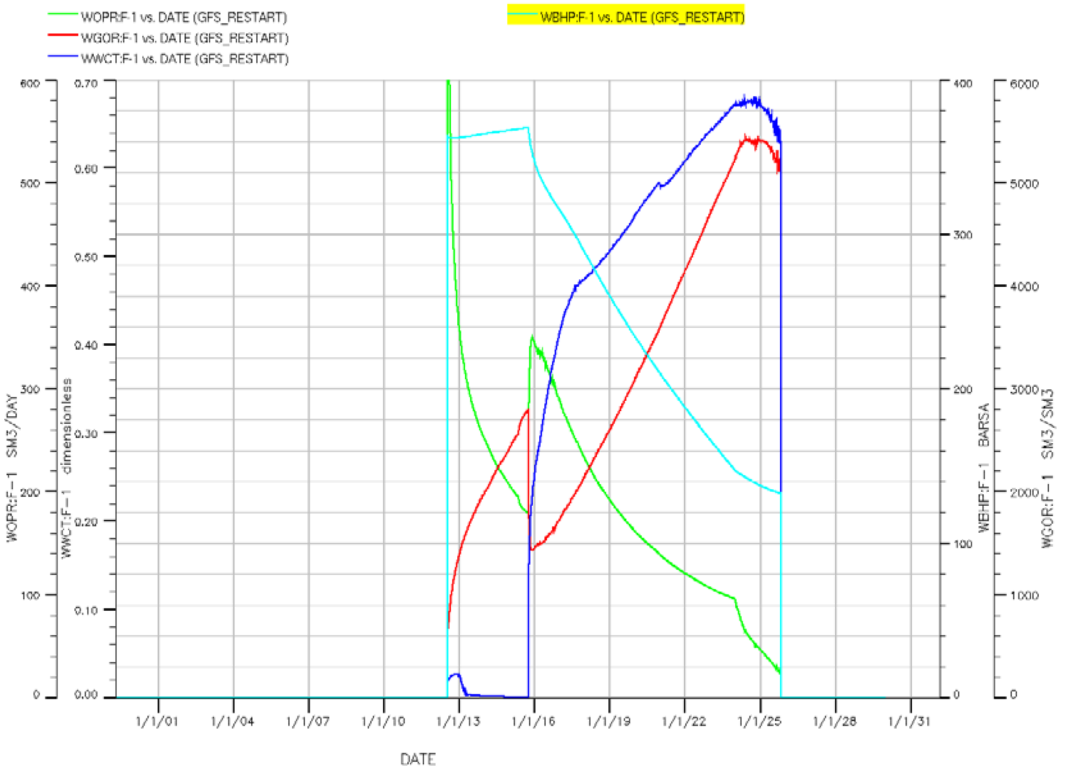


Well GI-4

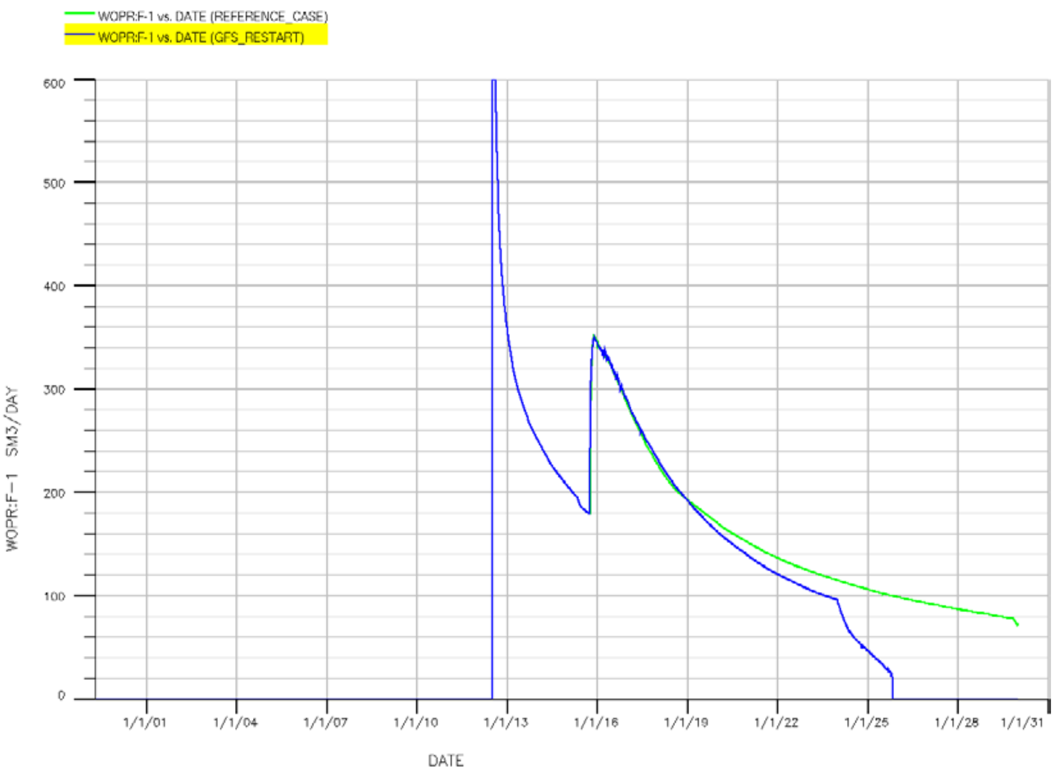


The Existing Wells

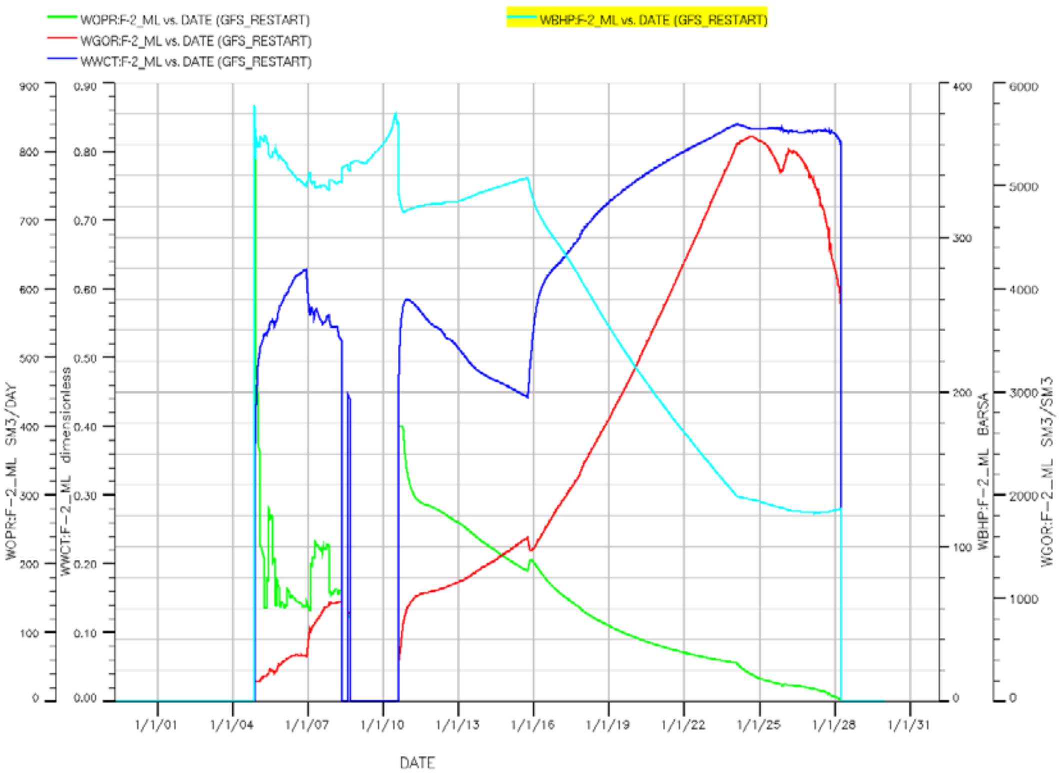
Well F-1 (Extended Case)



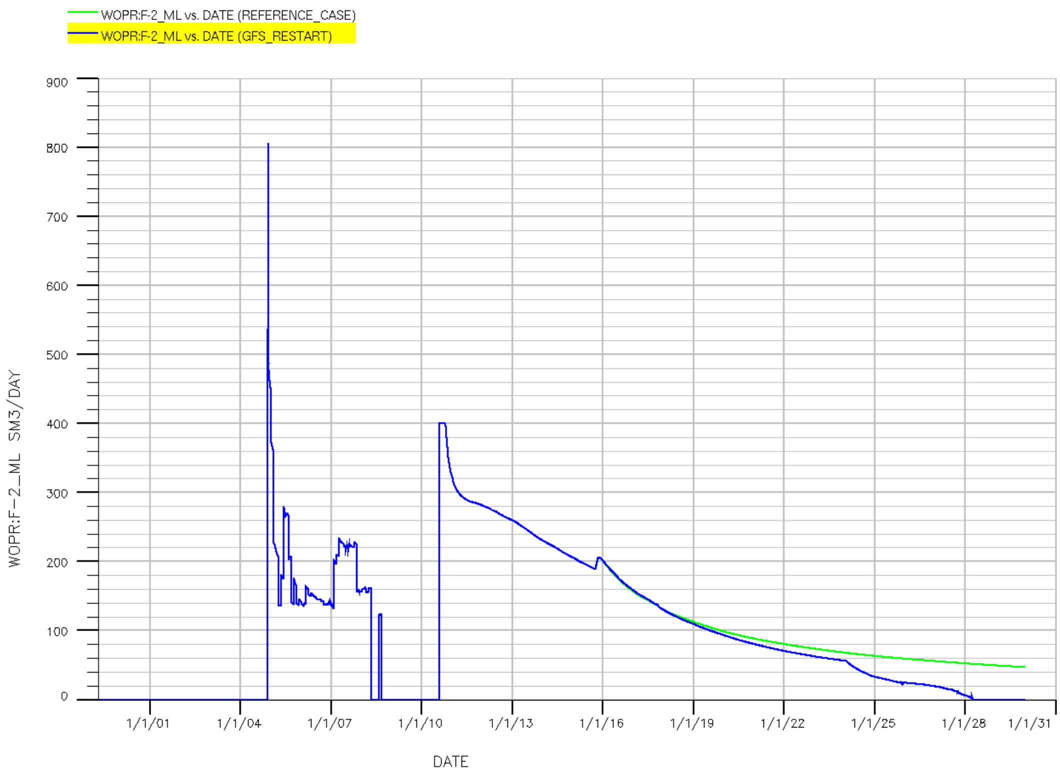
WOPR-F-1 (Reference Case Vs Extended Case)



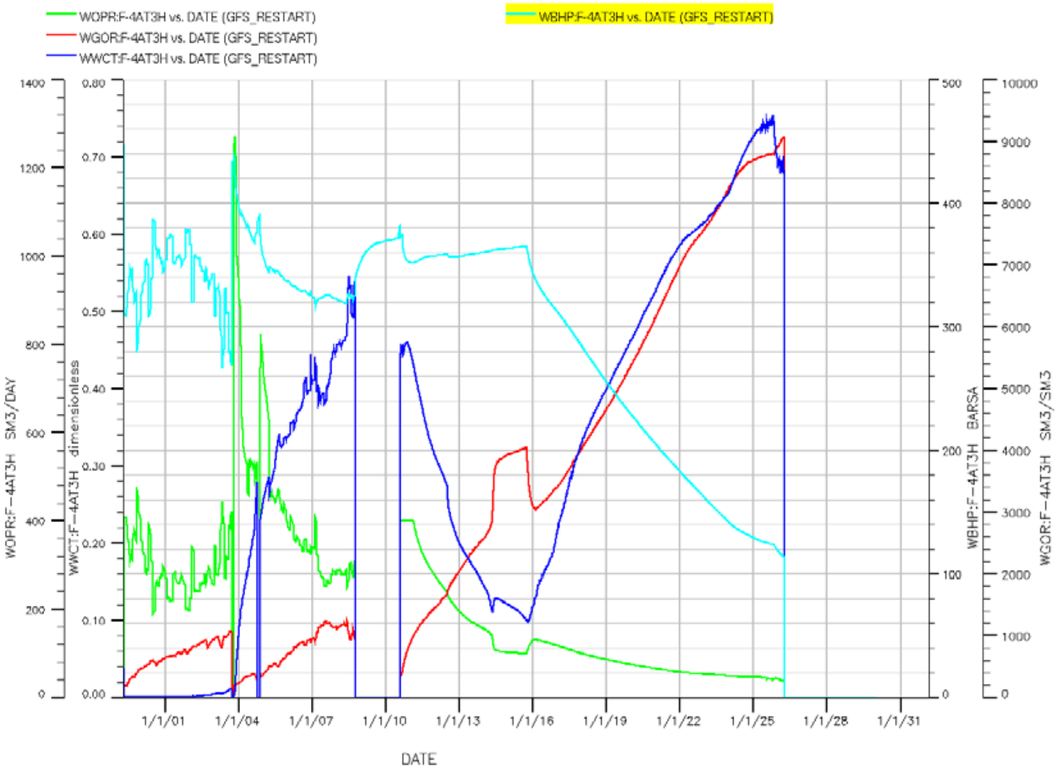
Well F-2_ML (Extended Case)



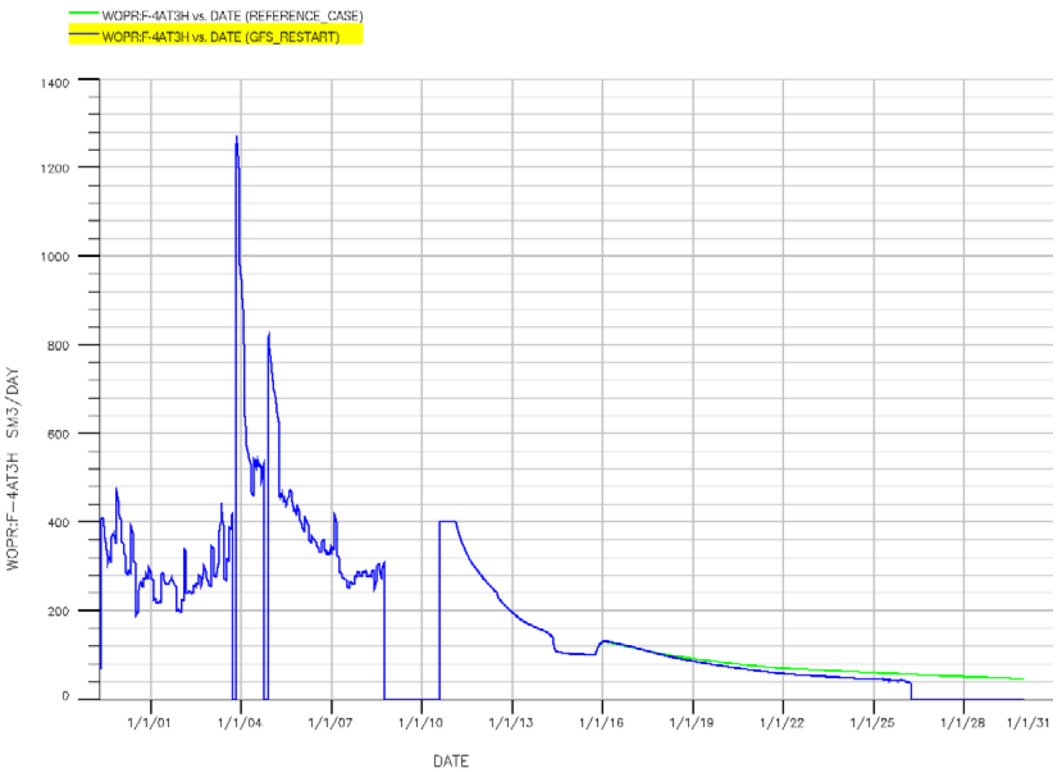
WOPR-F-2ML (Reference Case Vs Extended Case)



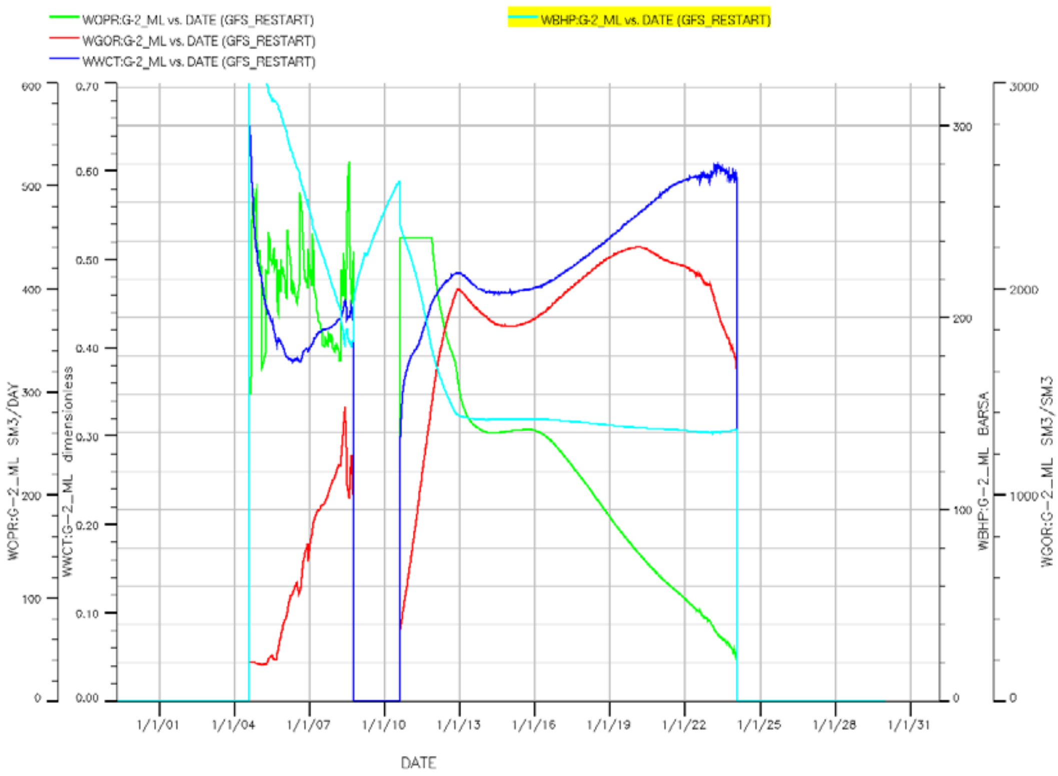
Well F-4AT3H (Extended Case)



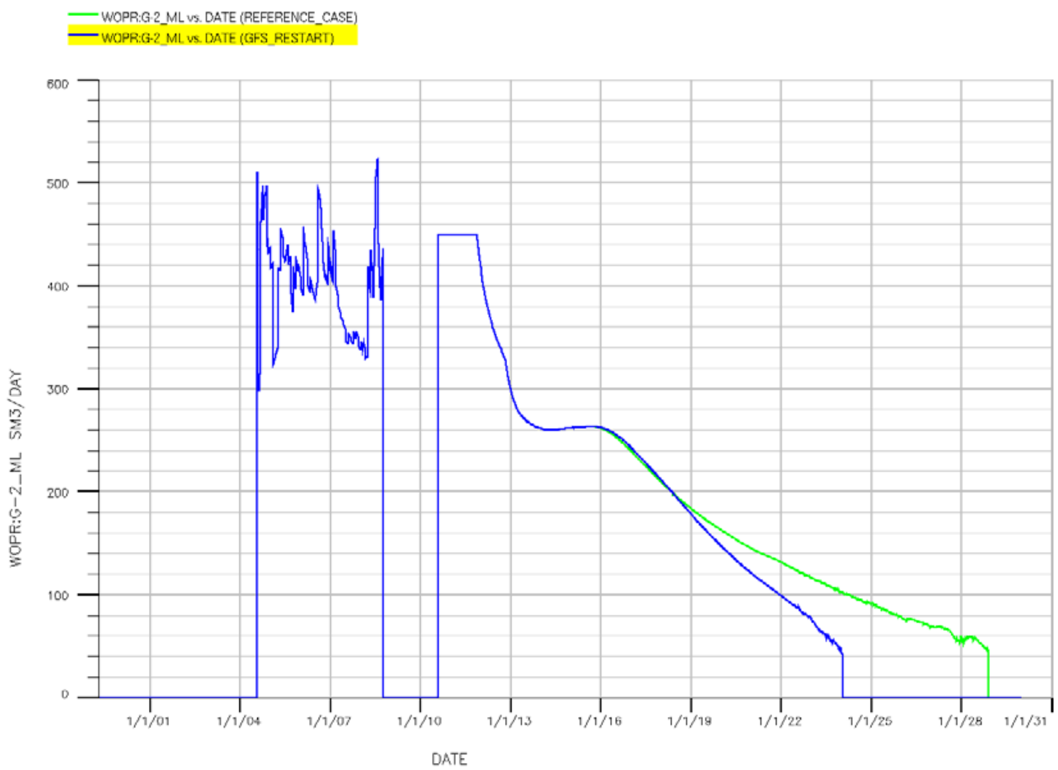
WOPR-F-4AT3H (Reference Case Vs Extended Case)



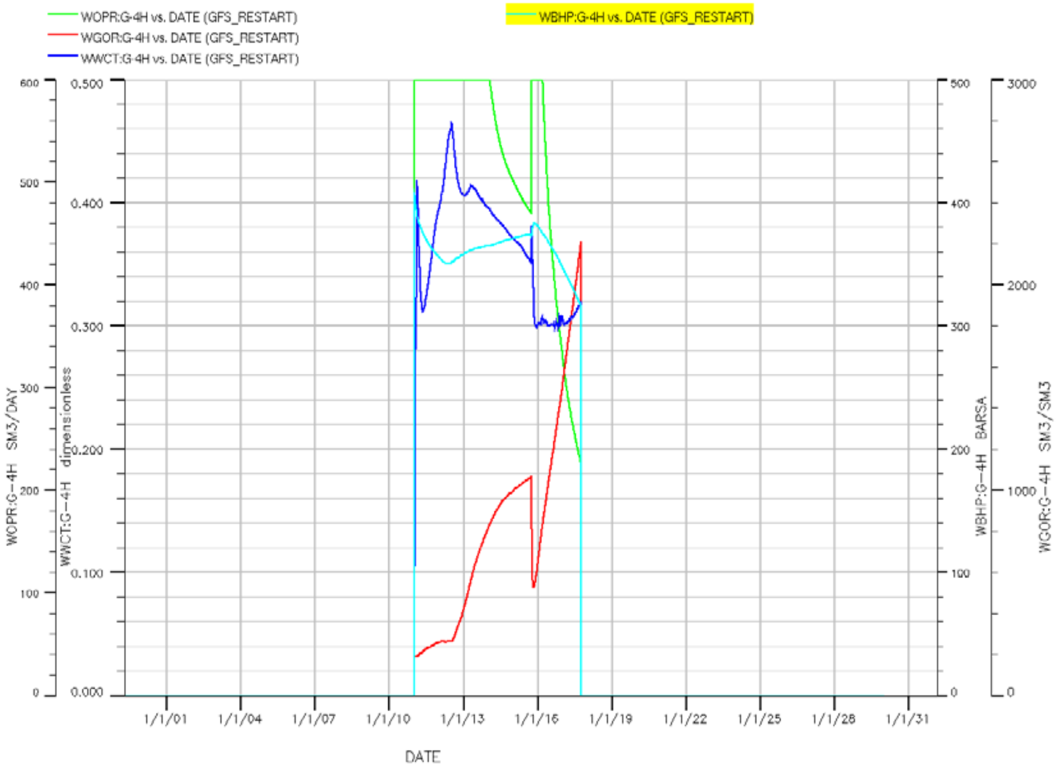
Well G-2_ML (Extended Case)



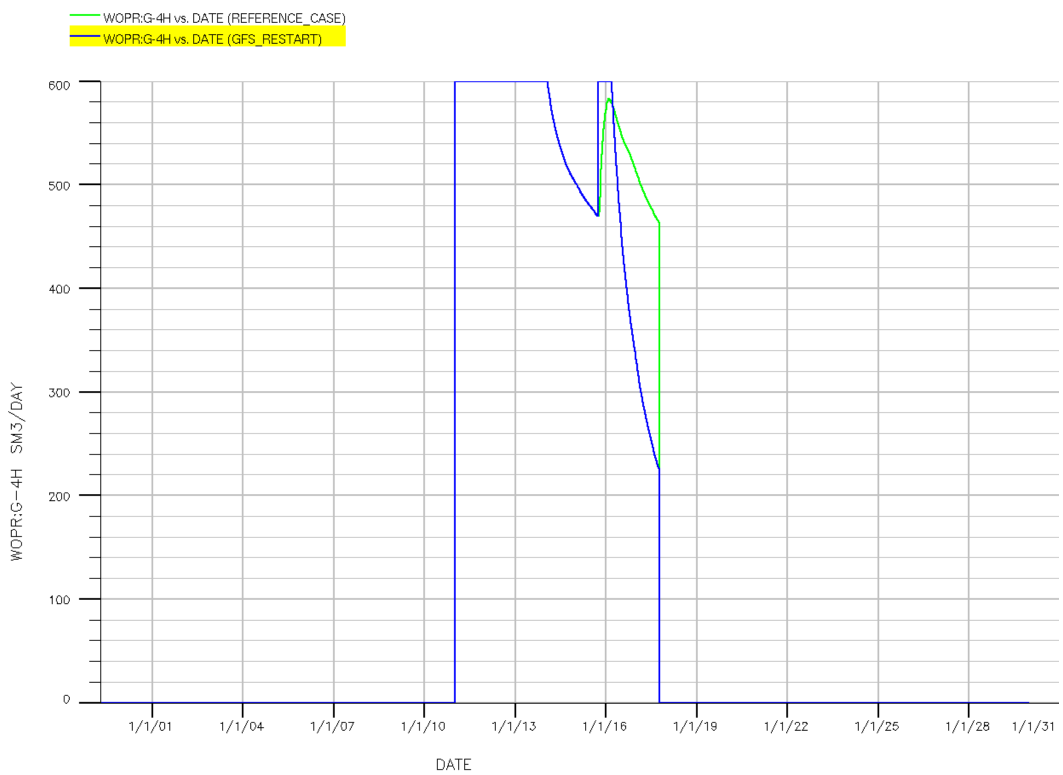
WOPR-G-2ML (Reference Case Vs Extended Case)



Well G-4H (Extended Case)



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

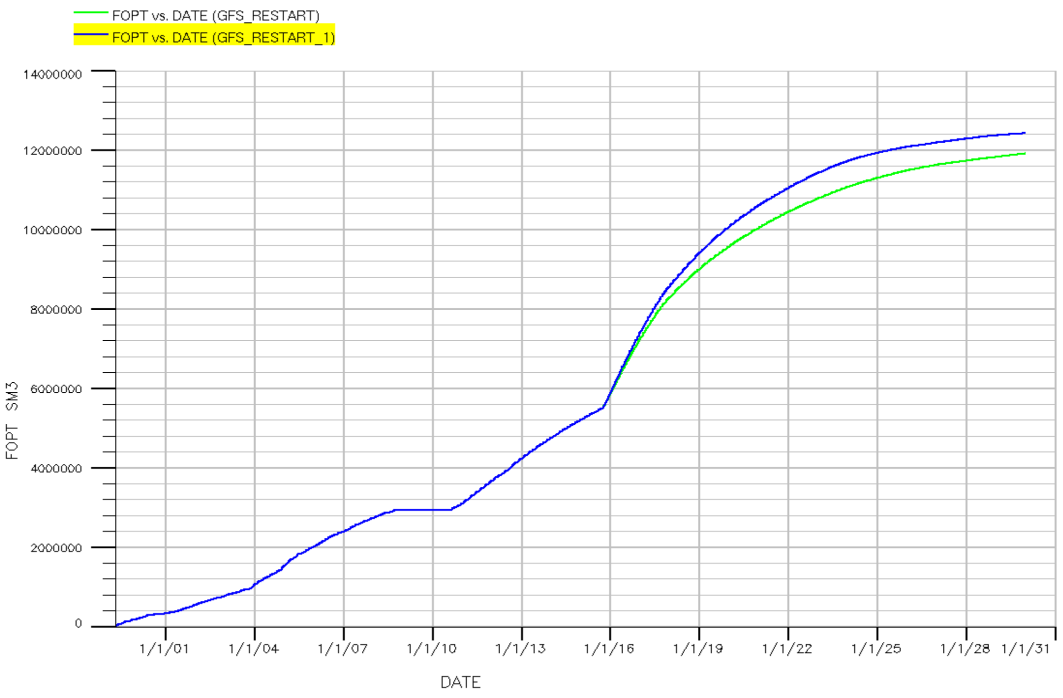


SCENARIO-1A (Activate Well G1-H)

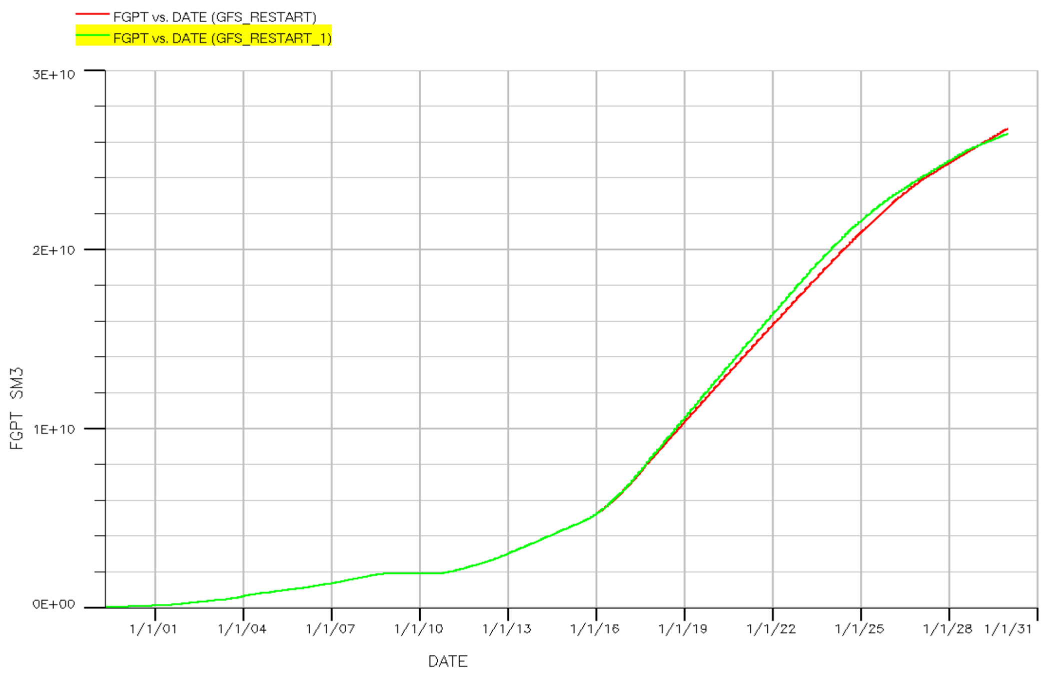
Field Charts

GFS_RESTART vs GFS_RESTART_1

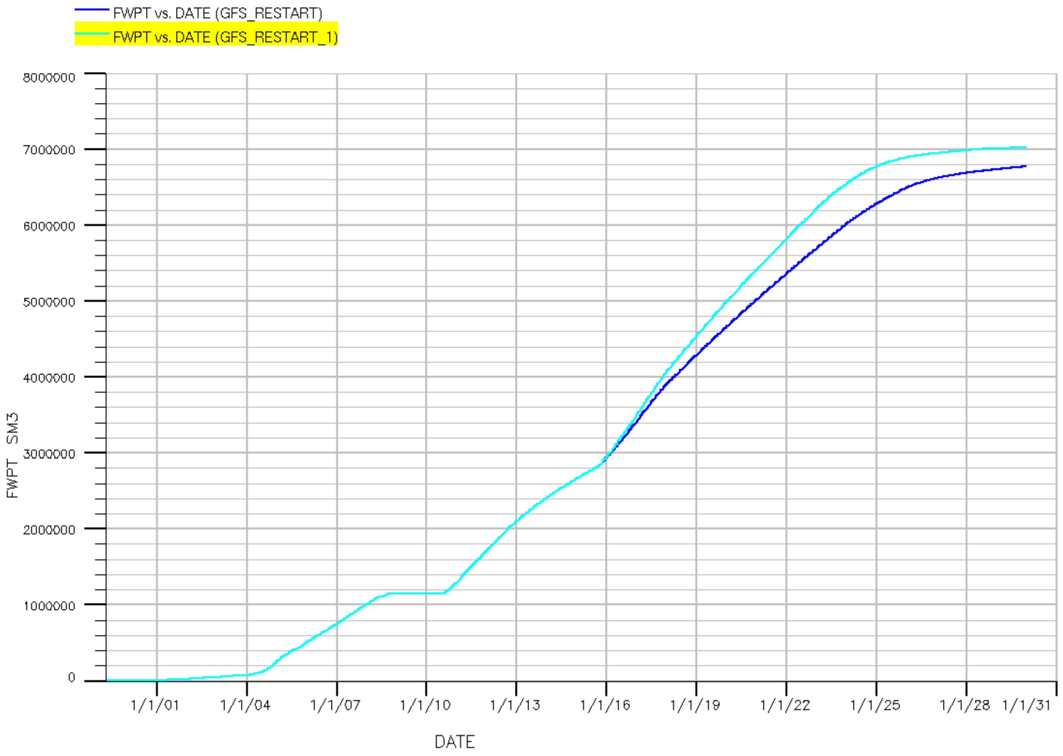
Field Oil Production Total (FOPT)



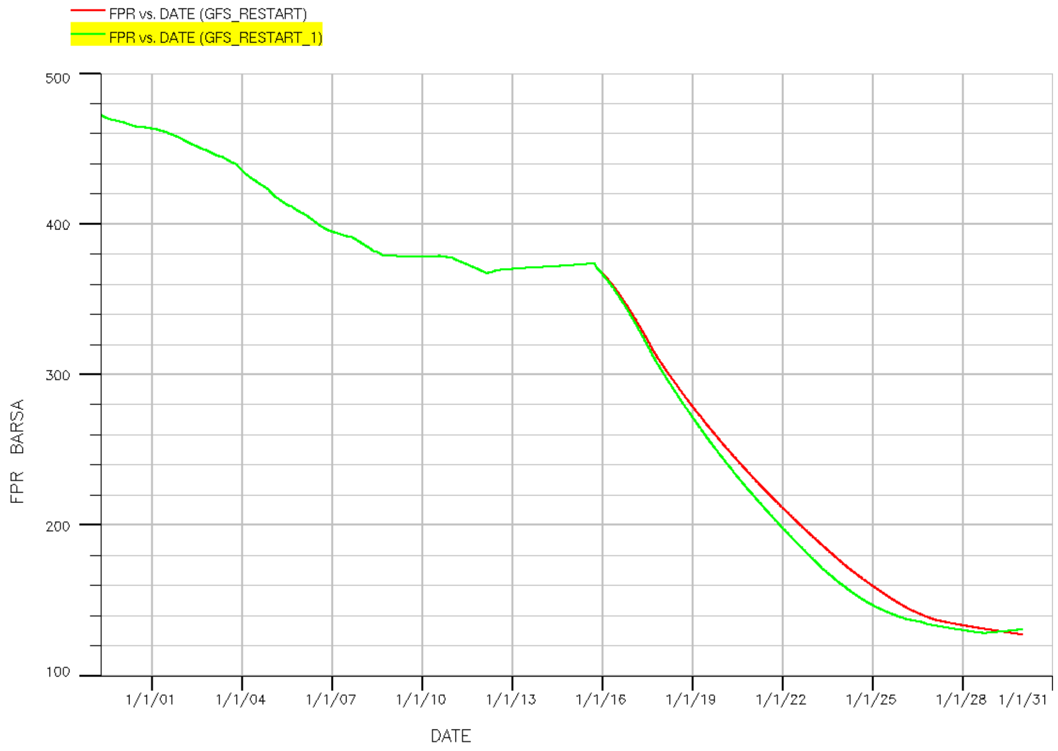
Field Gas Production Total (FGPT)



Field Water Production Total (FWPT)

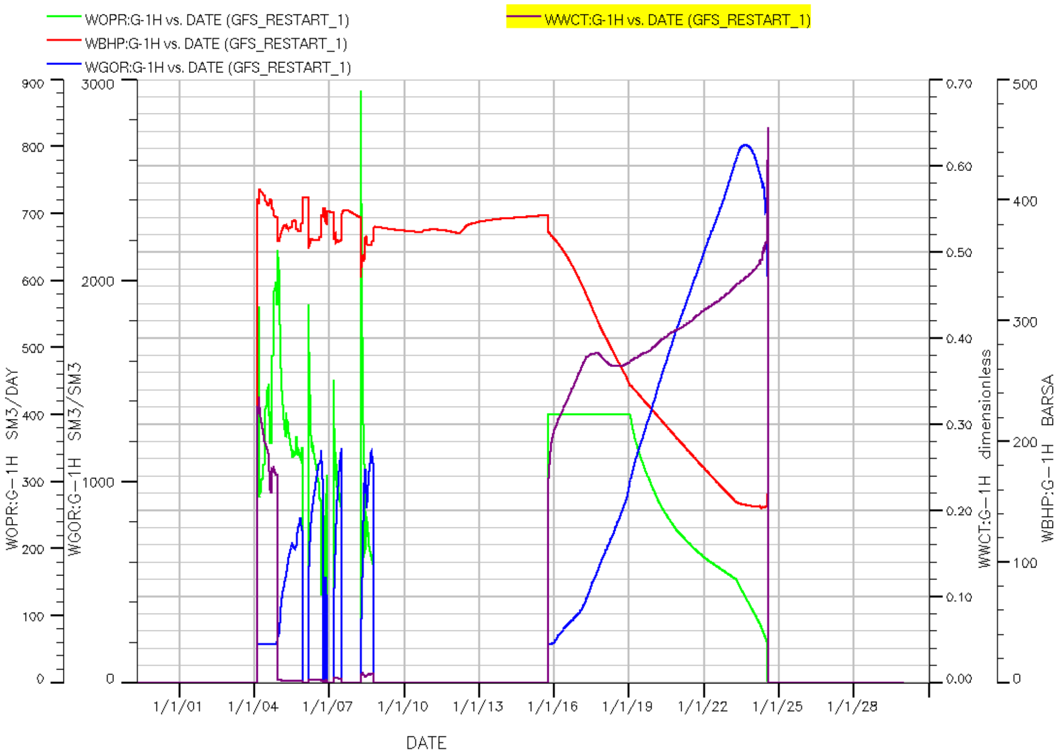


Field Pressure



Well Chart

Well G1-H

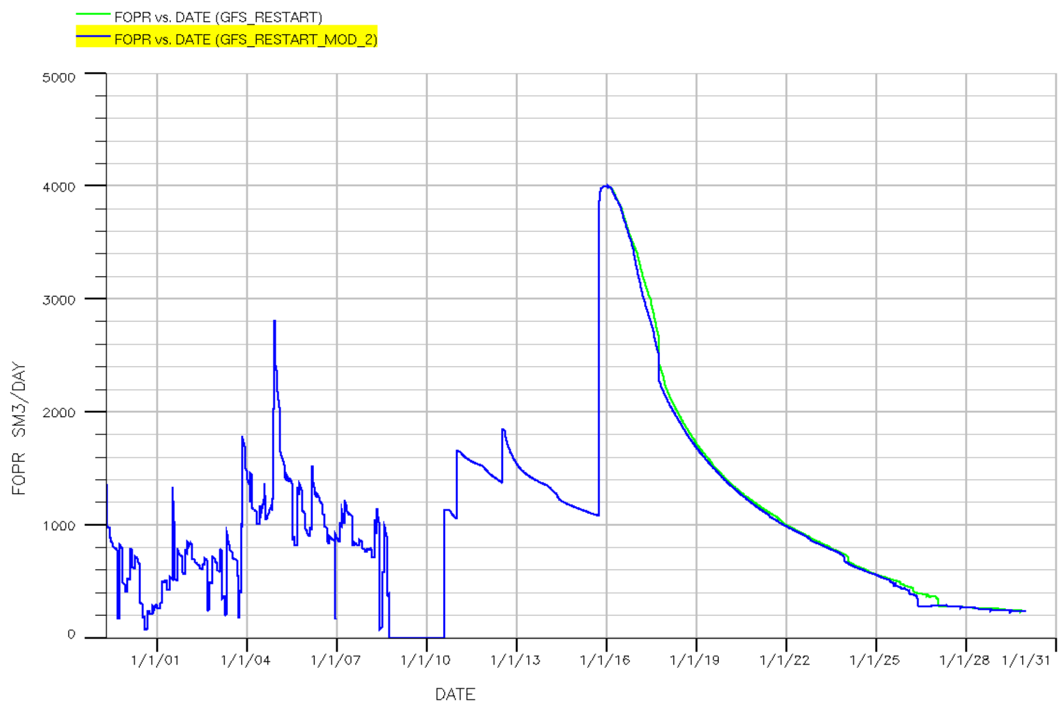


Appendix B: Scenario-2 Statoil Initial Plan - Modified Well Trajectory Charts

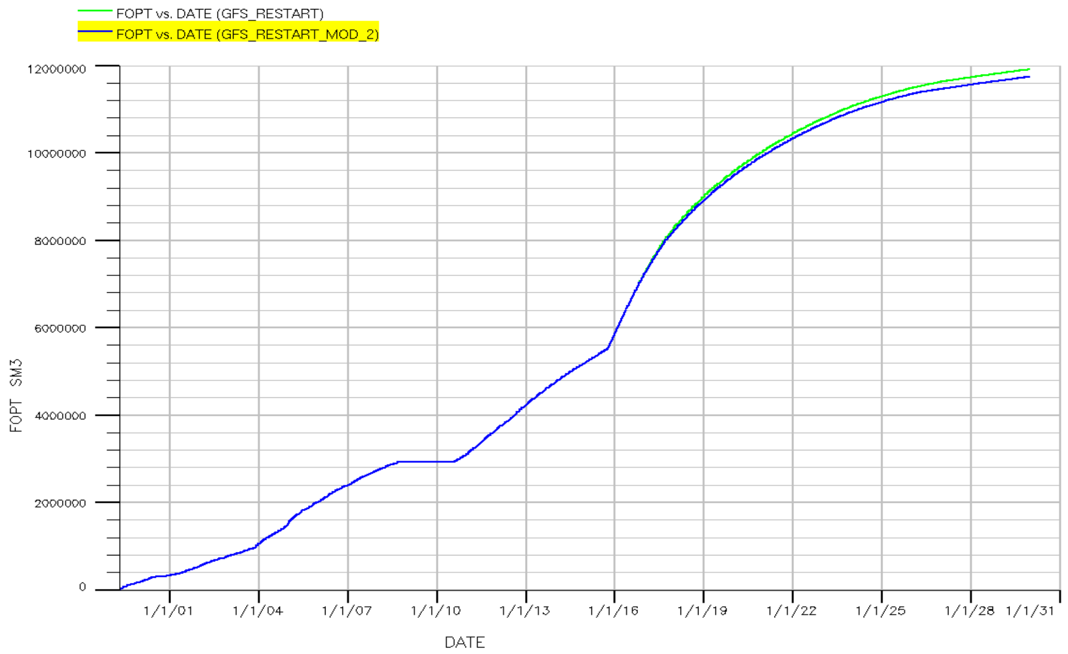
Field Charts

GFS_RESTART VS GFS_RESTART_MOD_2

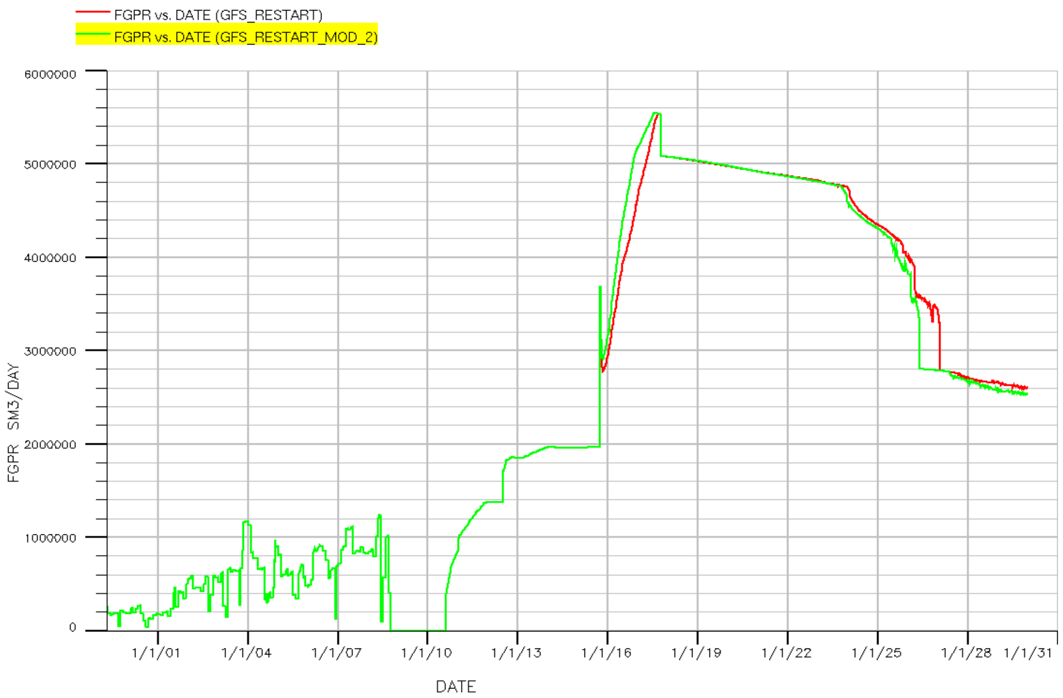
Field Oil Production Rate (FOPR)



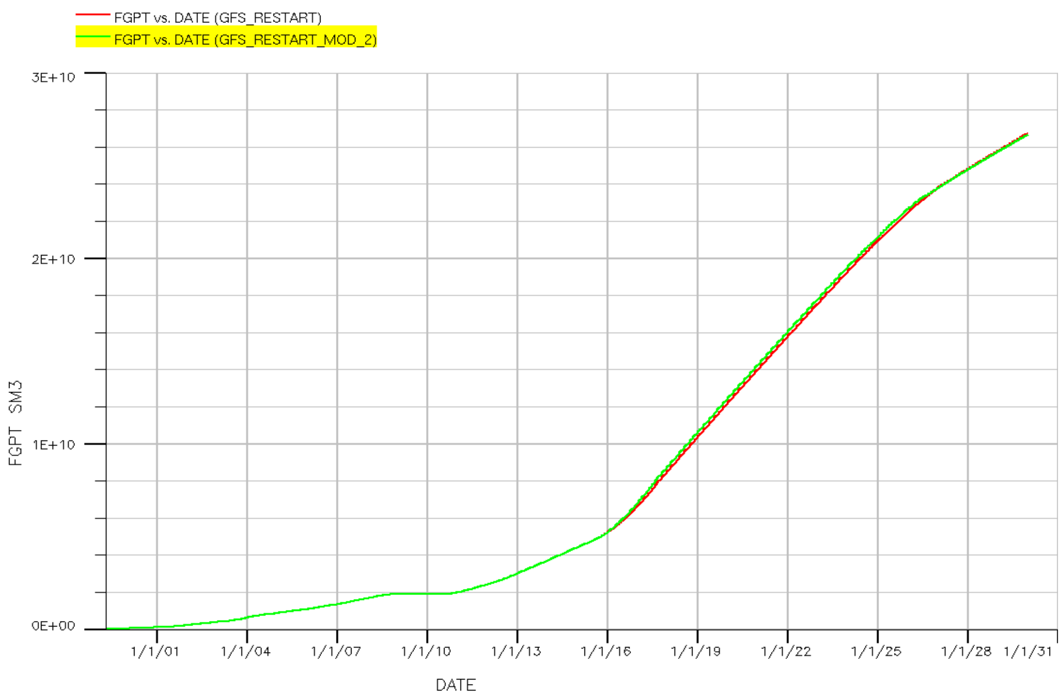
Field Oil Production Total (FOPT)



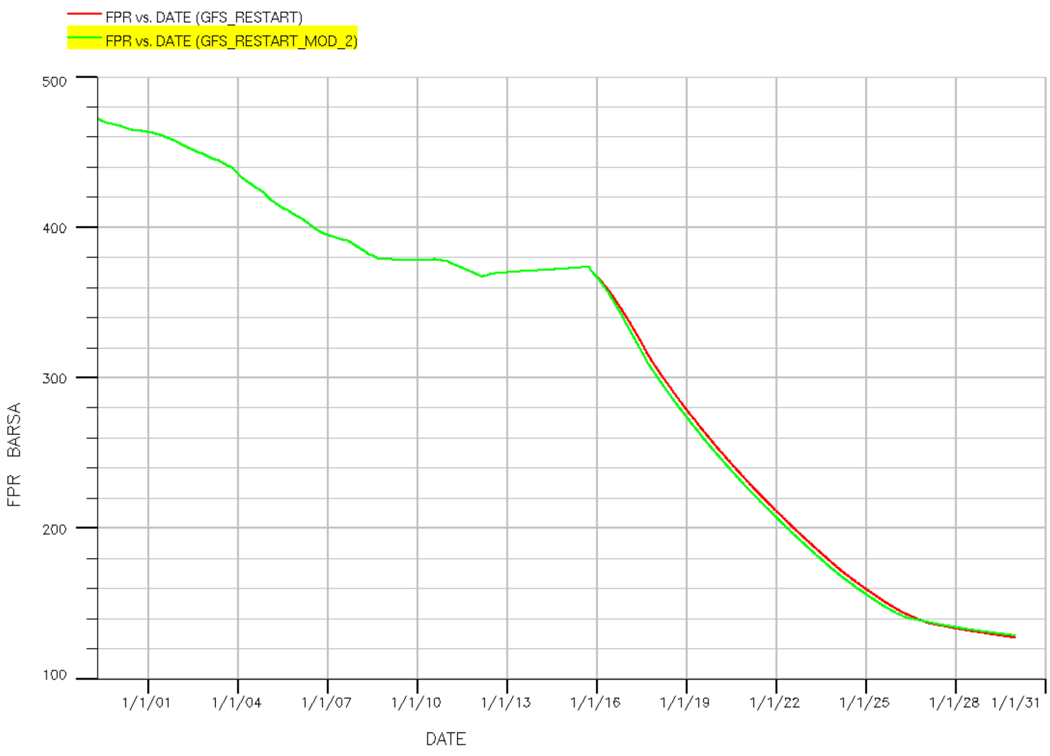
Field Gas Production Rate (FGPR)



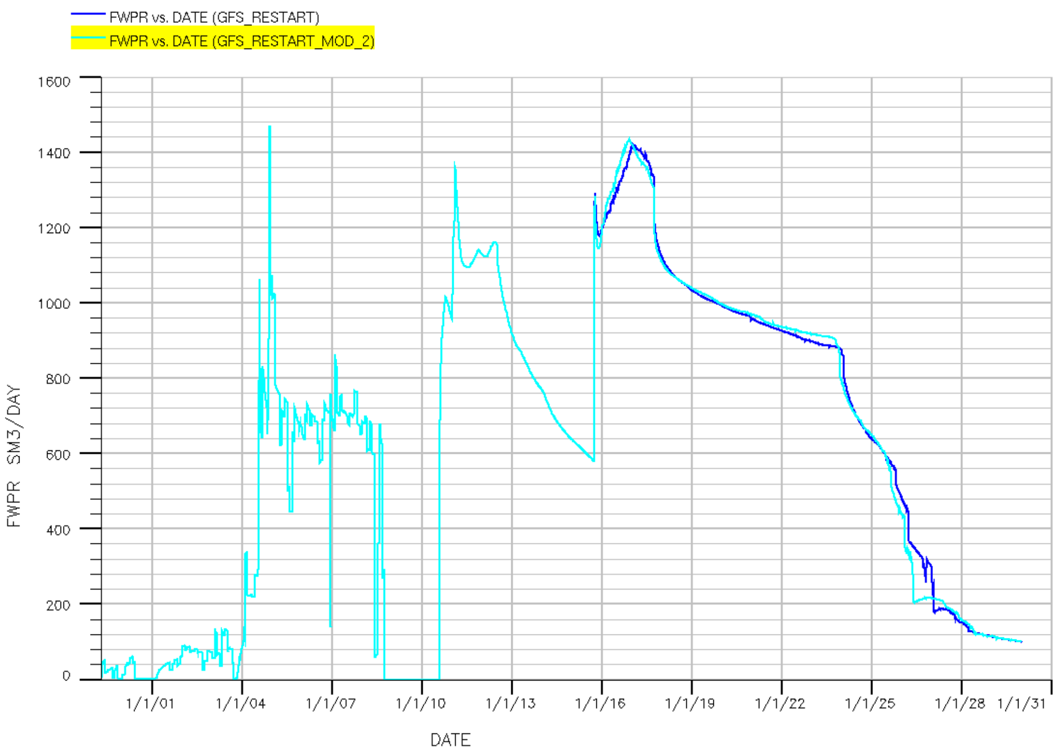
Field Gas Production Total (FGPT)



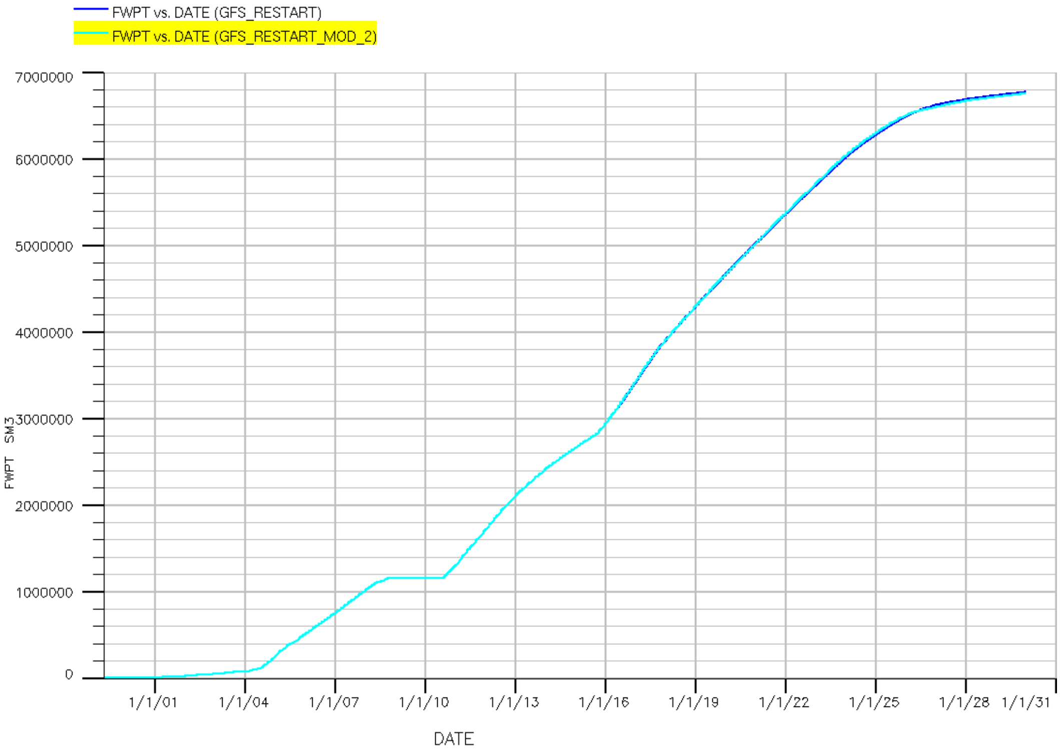
Field Pressure (FPR)



Field Water Production Rate (FWPR)

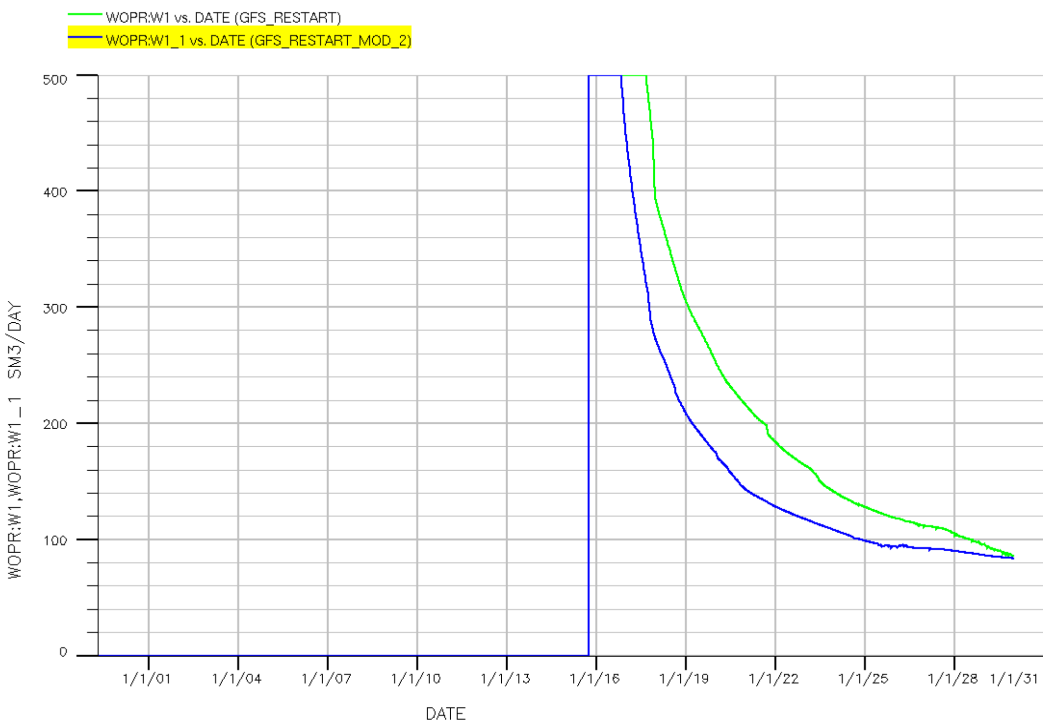


Field Water Production Total (FWPT)

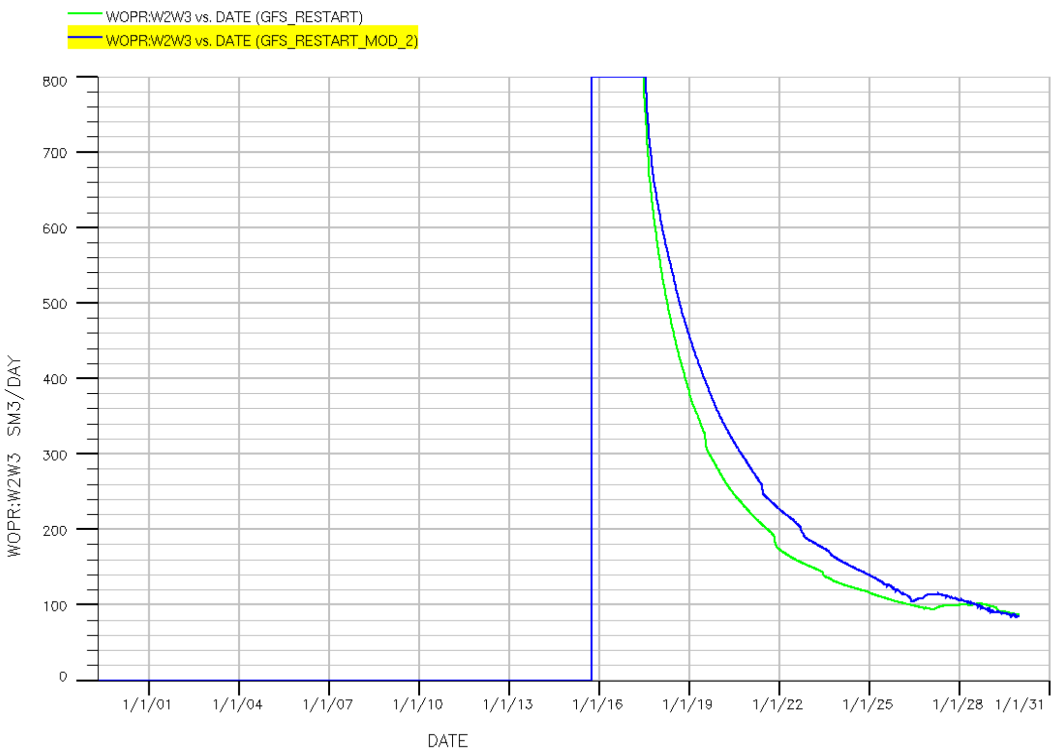


Well Charts

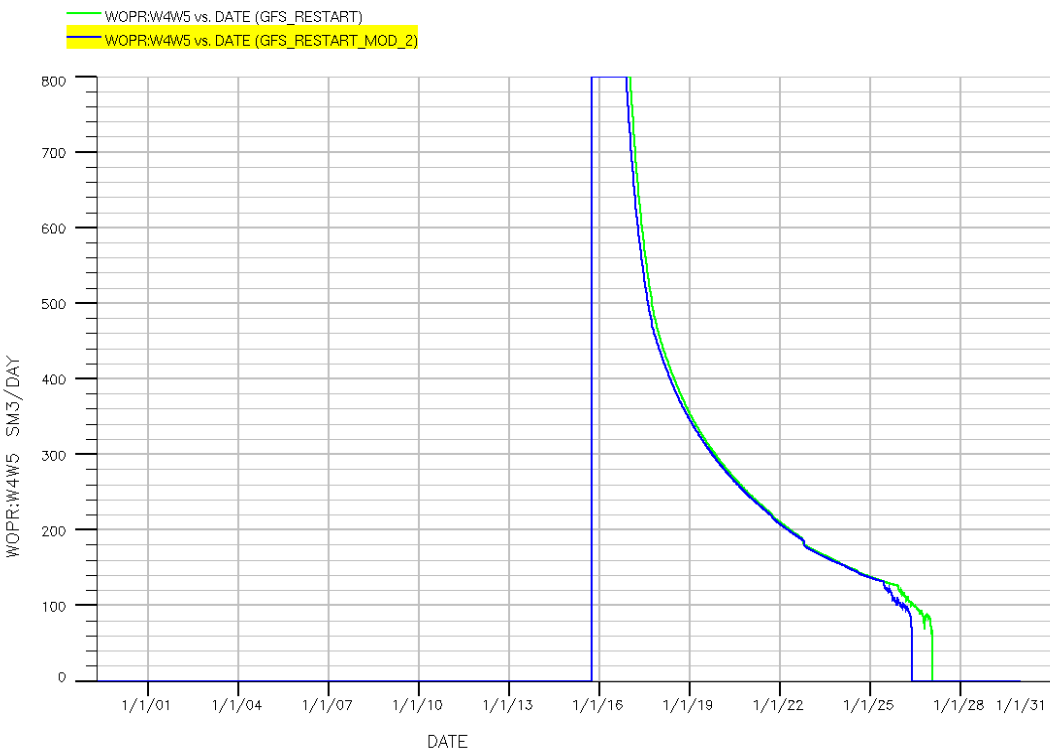
Well W1



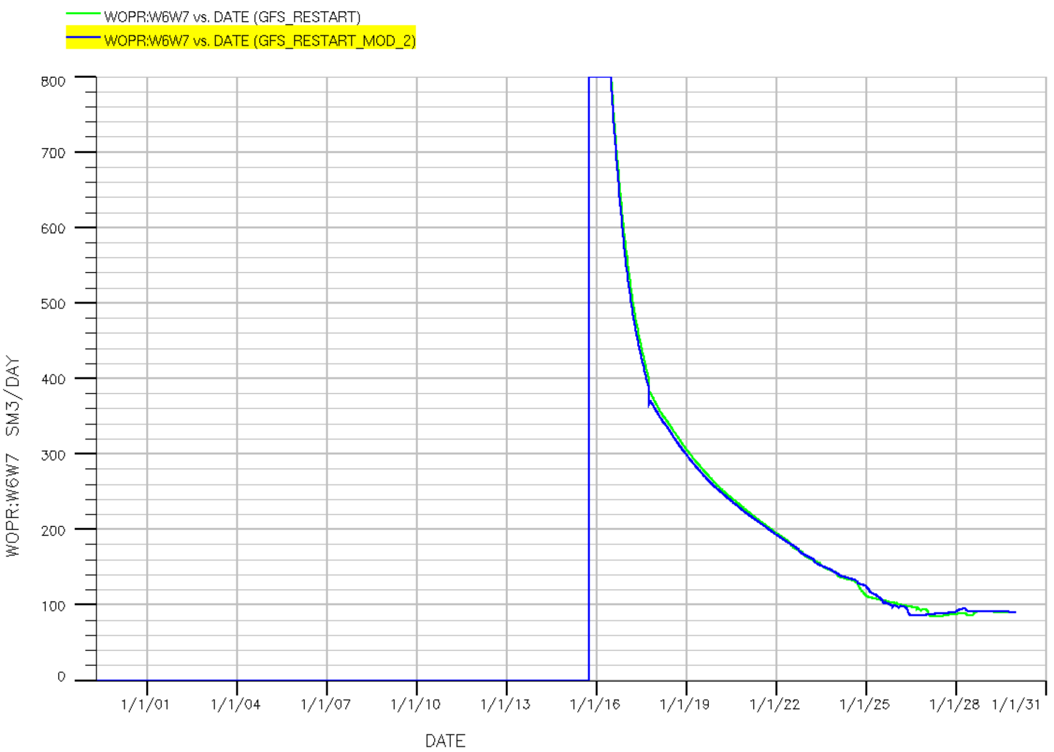
Well W2W3



Well W4W5



Well W6W7

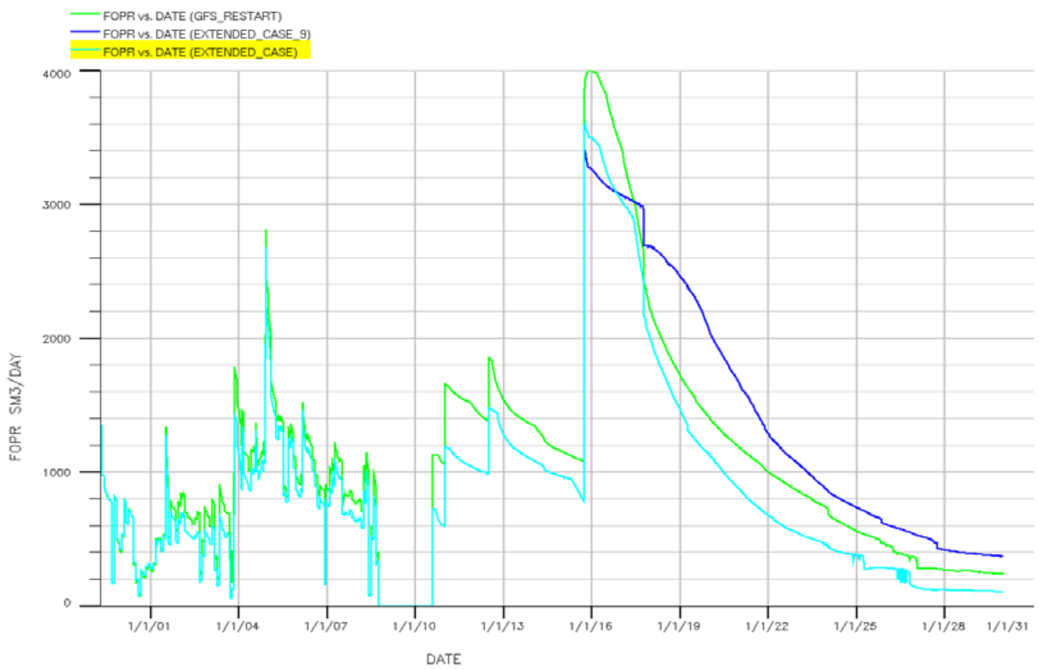


Appendix C: Scenario-3 Worst Reservoir Condition Charts (Transmissibility across all faults are zero)

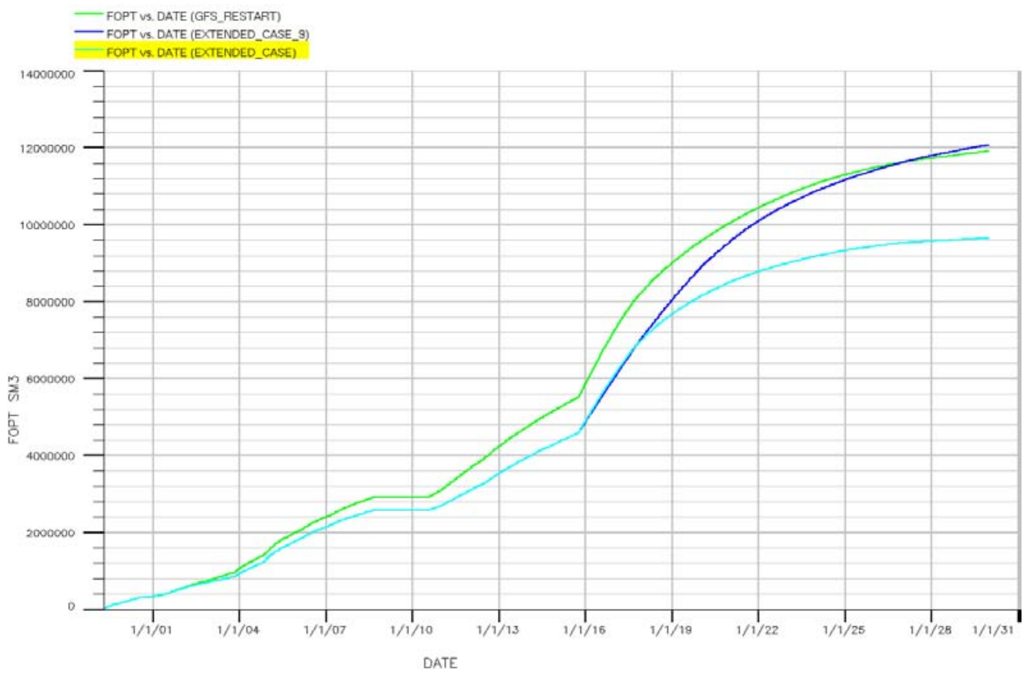
Field Charts

GFS_RESTART vs EXTENDED_CASE vs EXTENDED_CASE_9

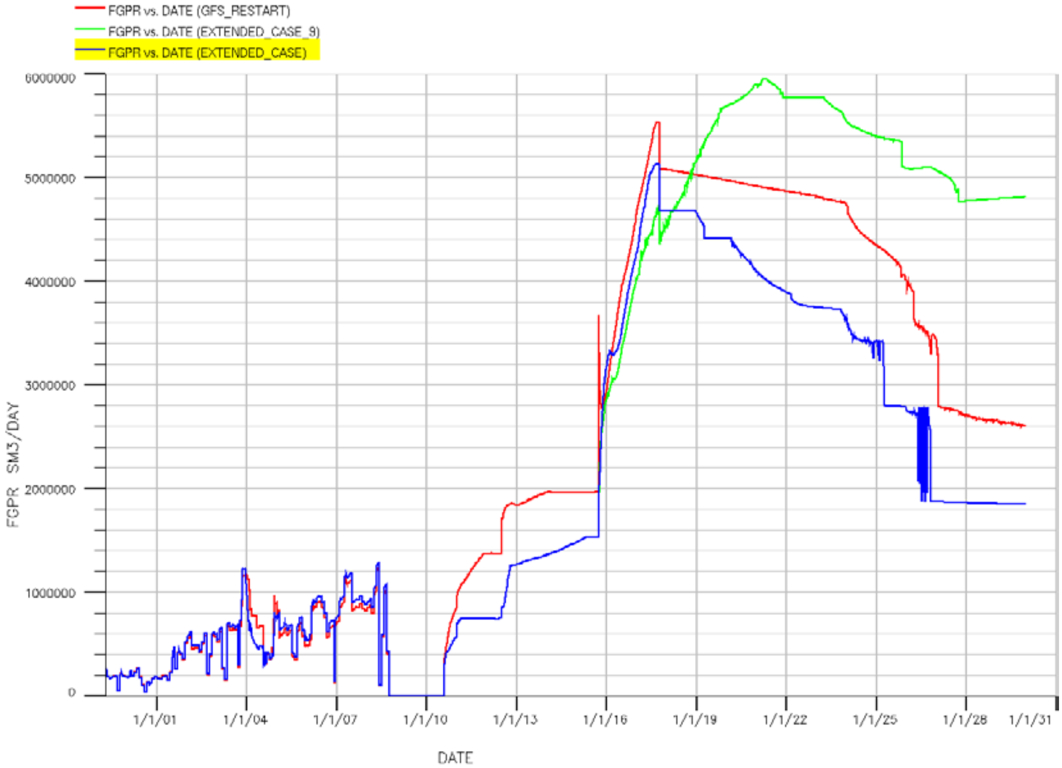
Field Oil Production Rate (FOPR)



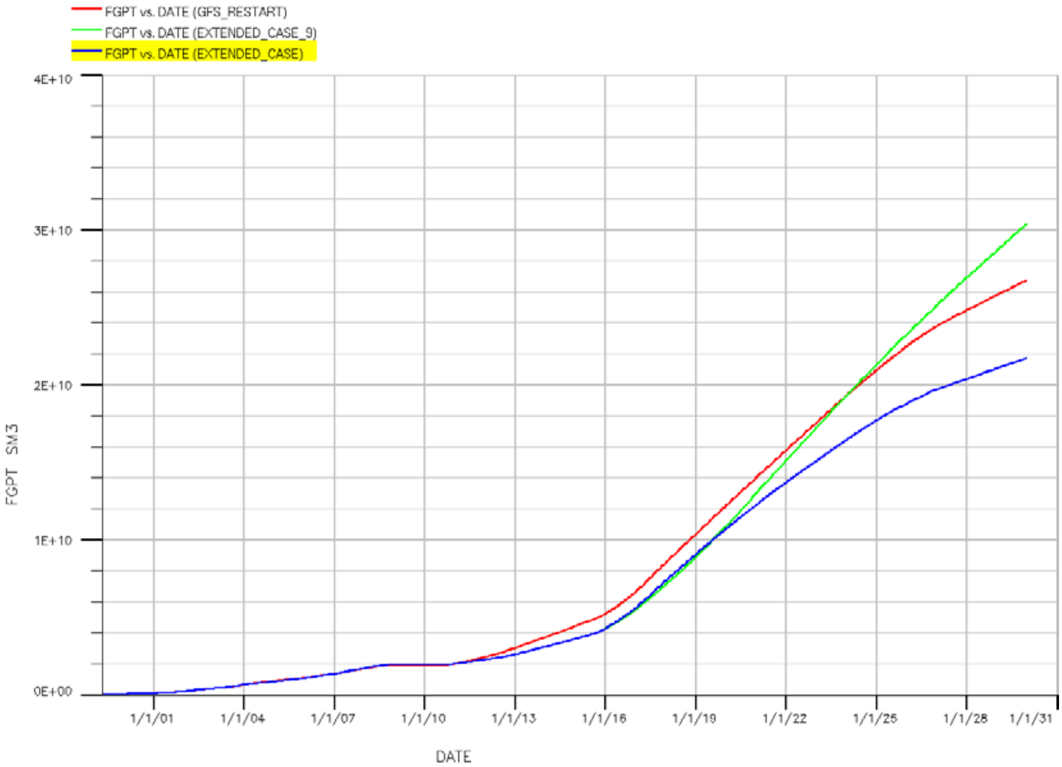
Field Oil Production Total (FOPT)



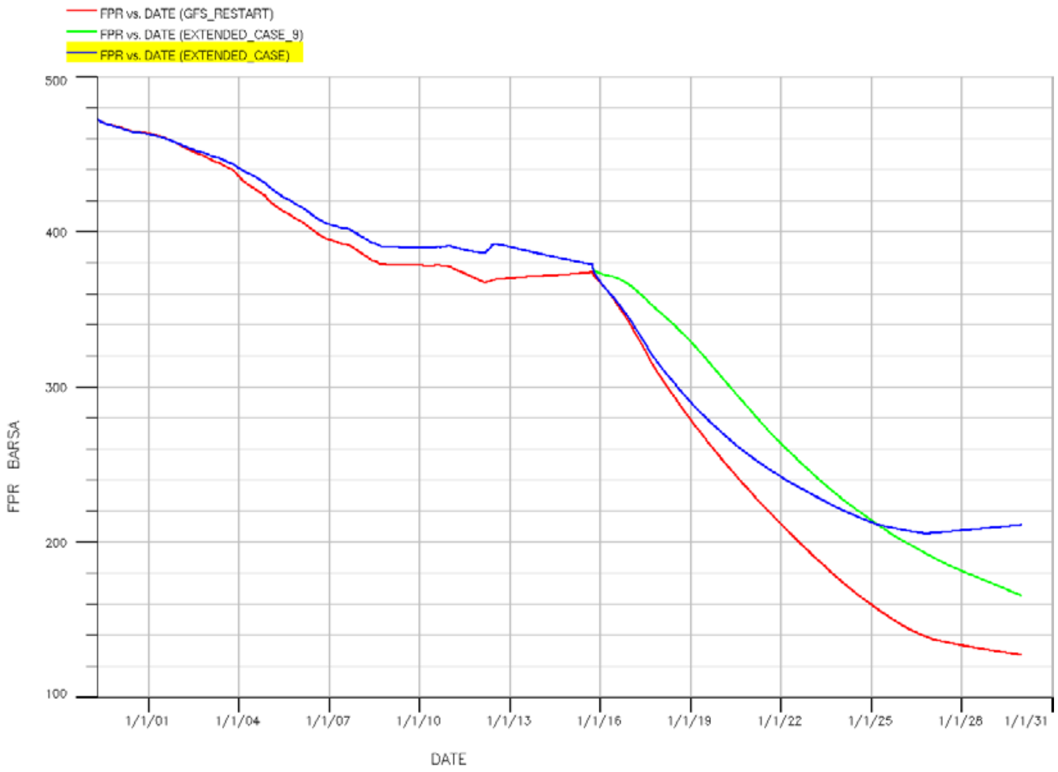
Field Gas Production Rate (FGPR)



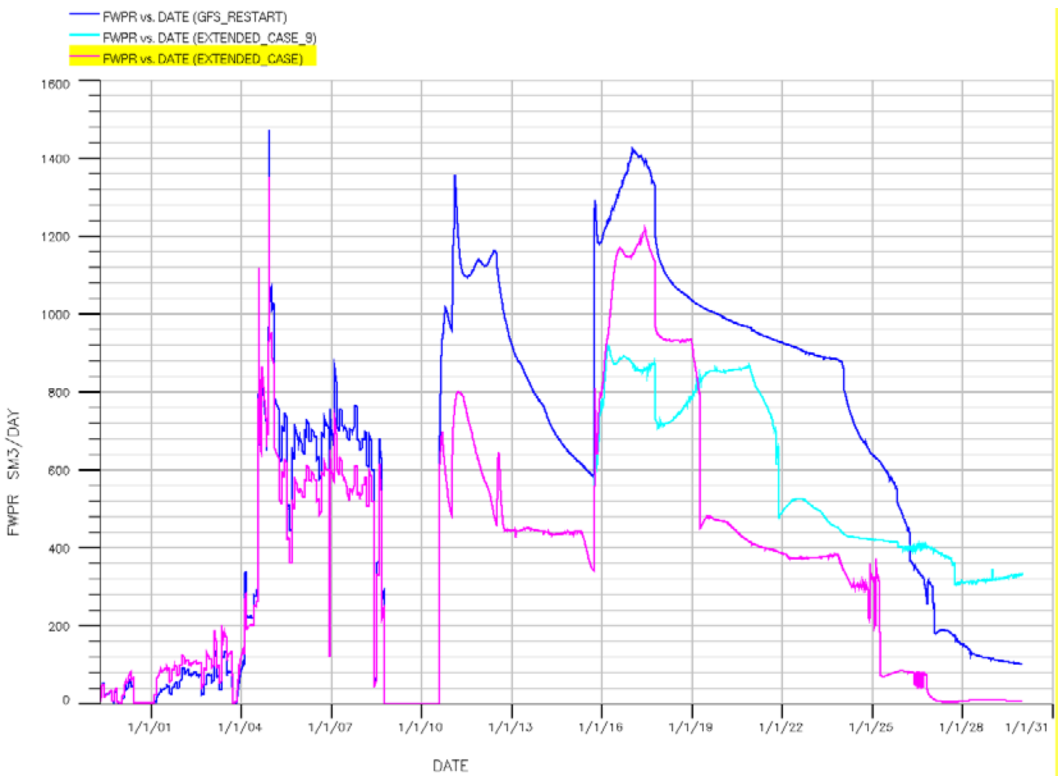
Field Gas Production Total (FGPT)



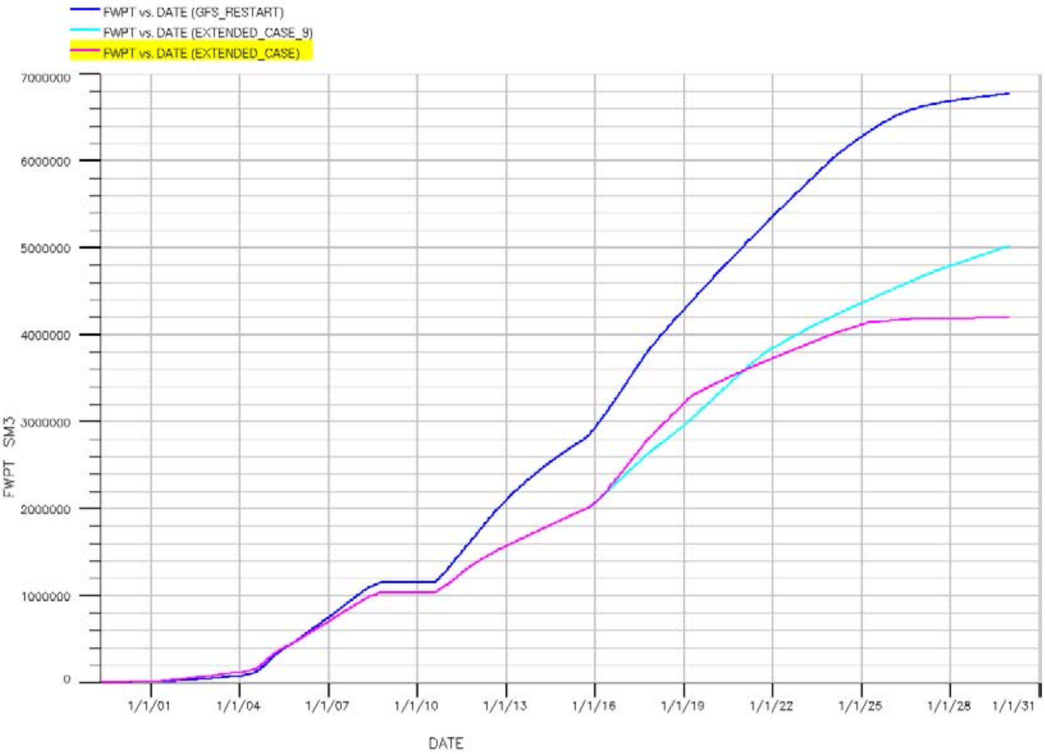
Field Pressure (FPR)



Field Water Production Rate (FWPR)

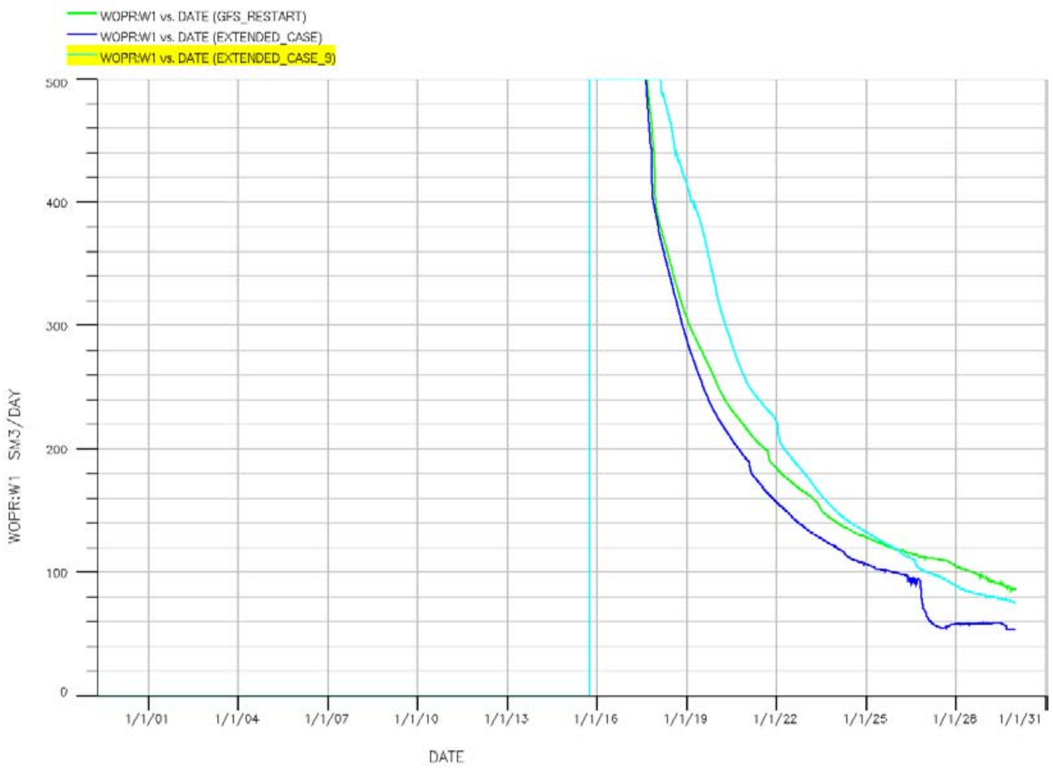


Field Water Production Total

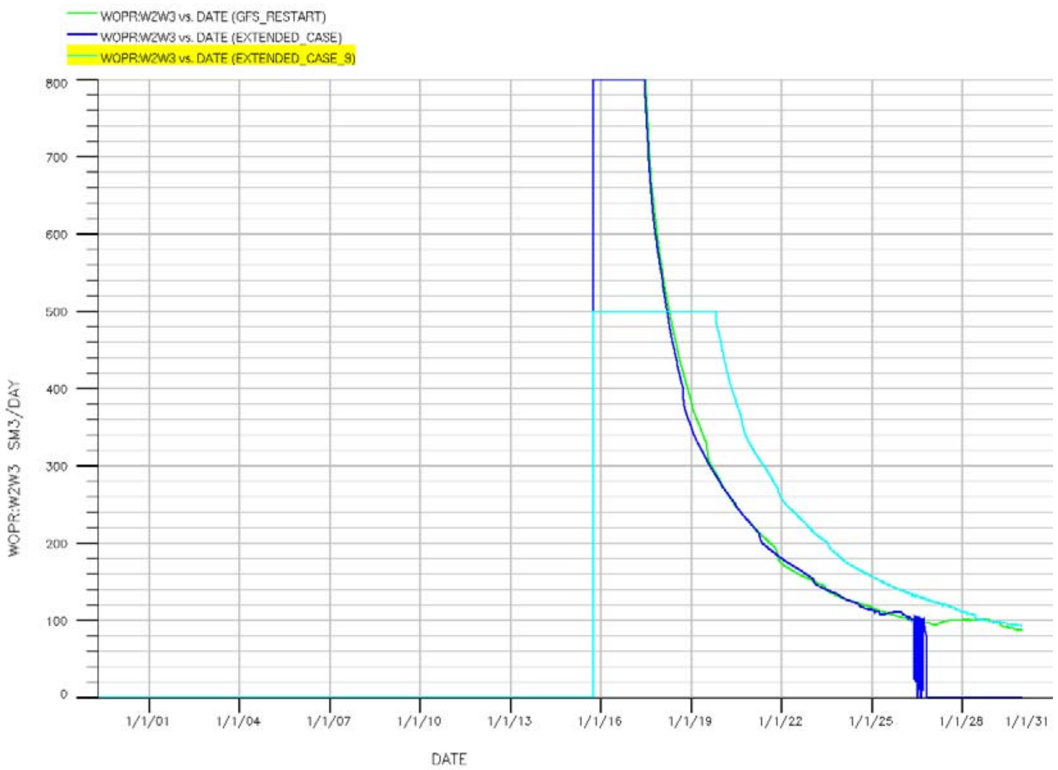


Well Charts

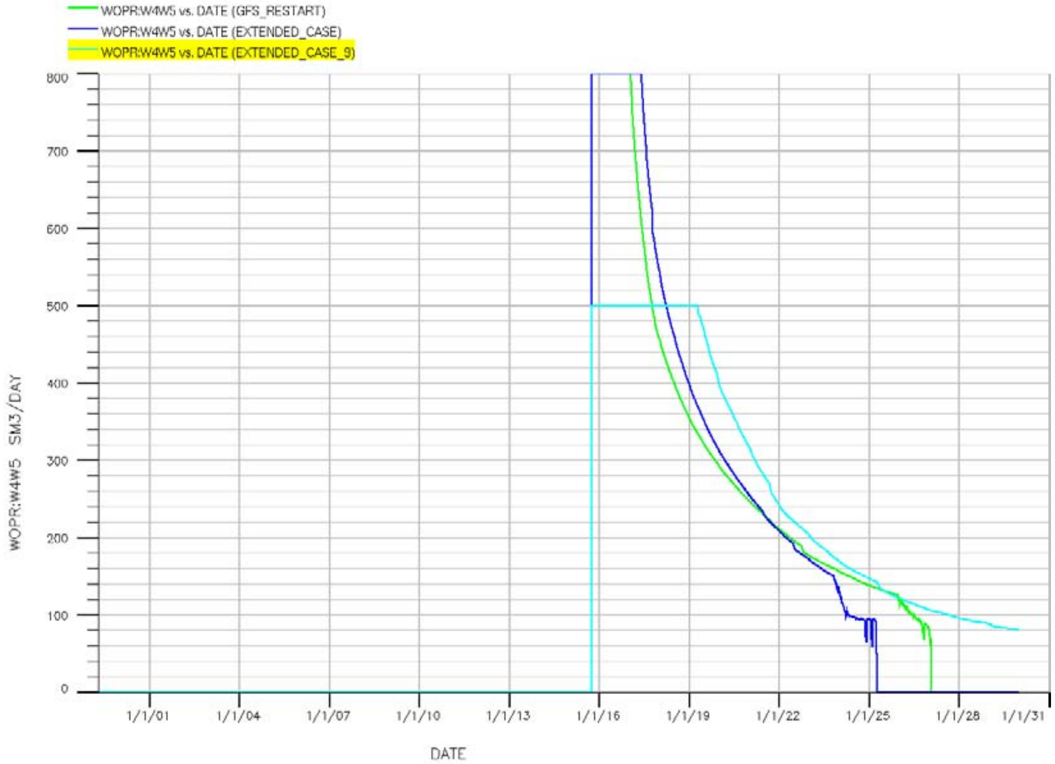
Well W1



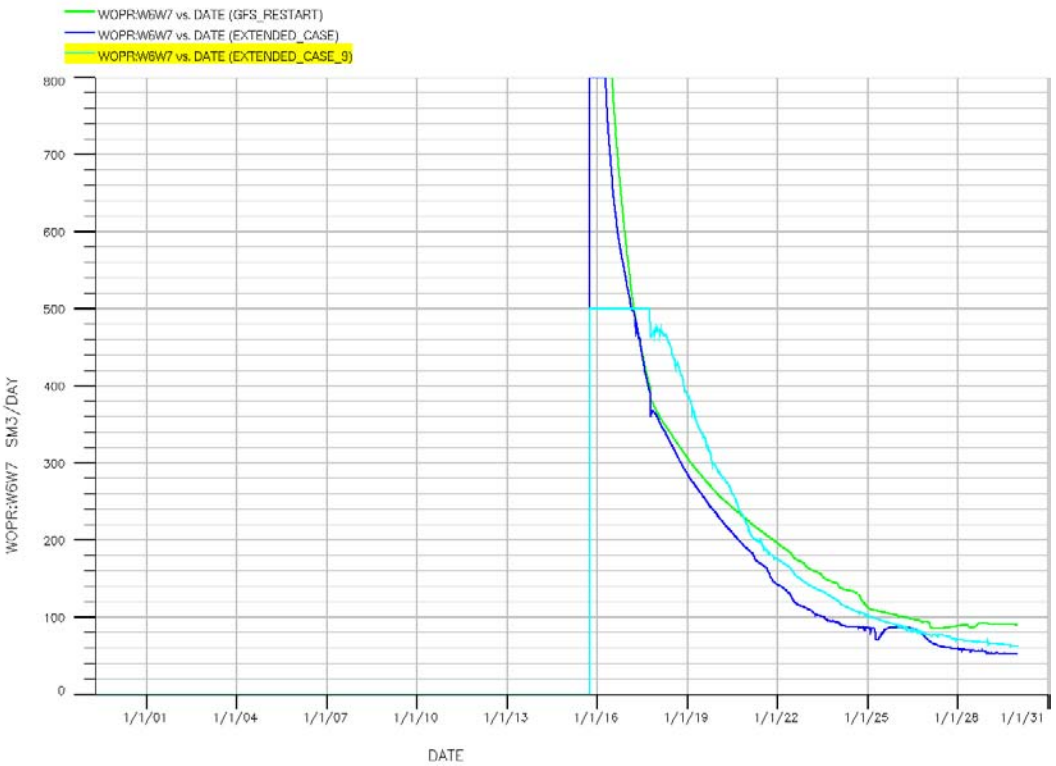
Well W2W3



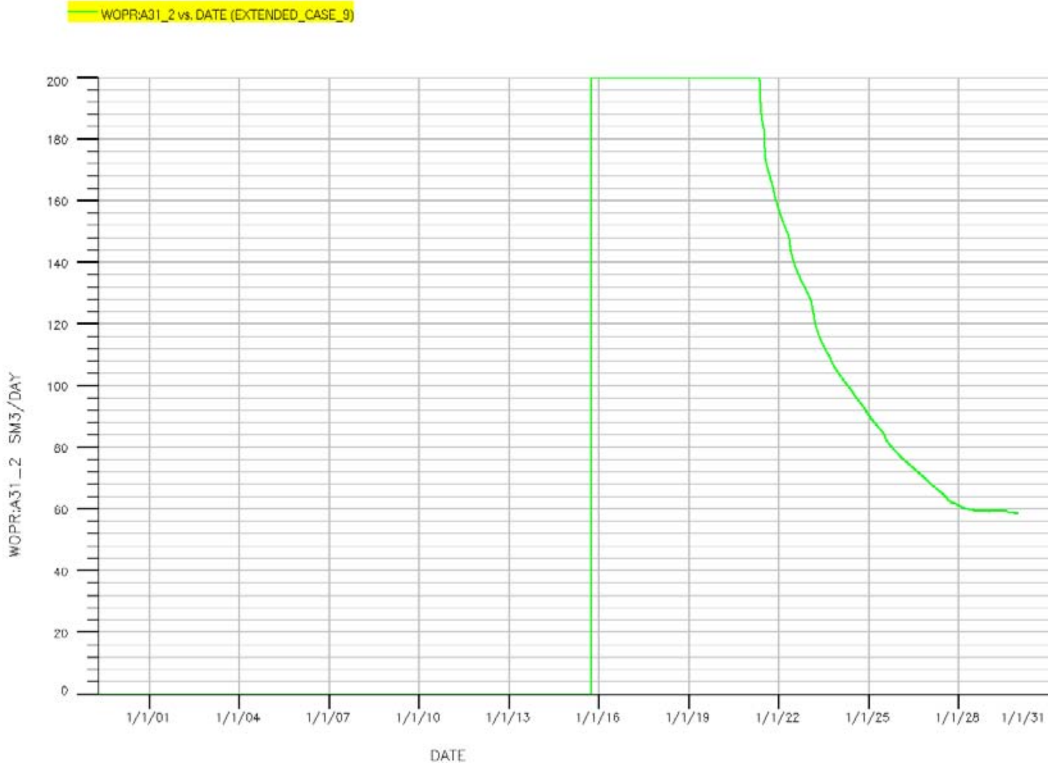
Well W4W5



Well W6W7

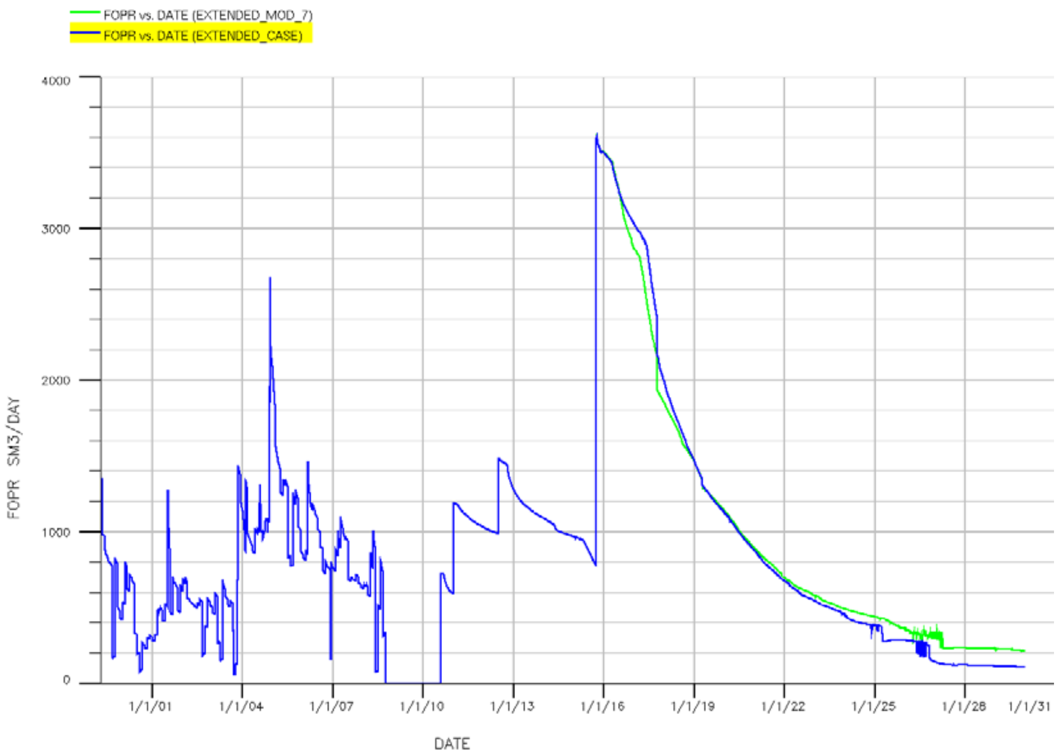


Well A31_2 (New proposed well)

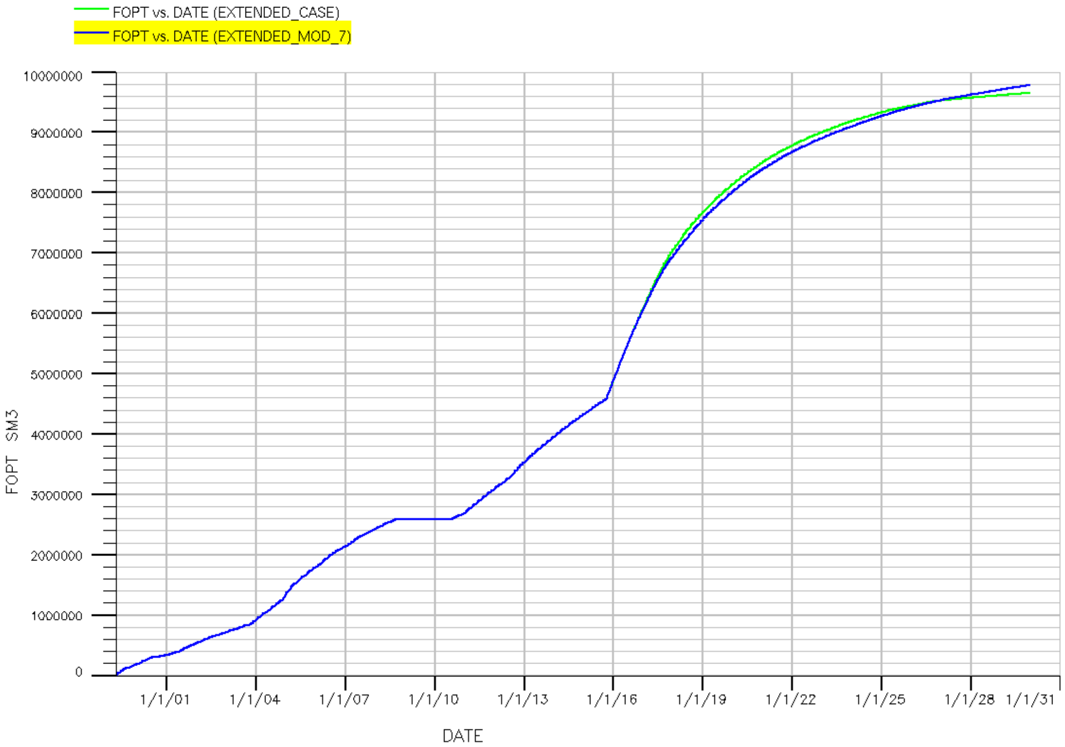


EXTENDED_CASE VS EXTENDED_MOD_7

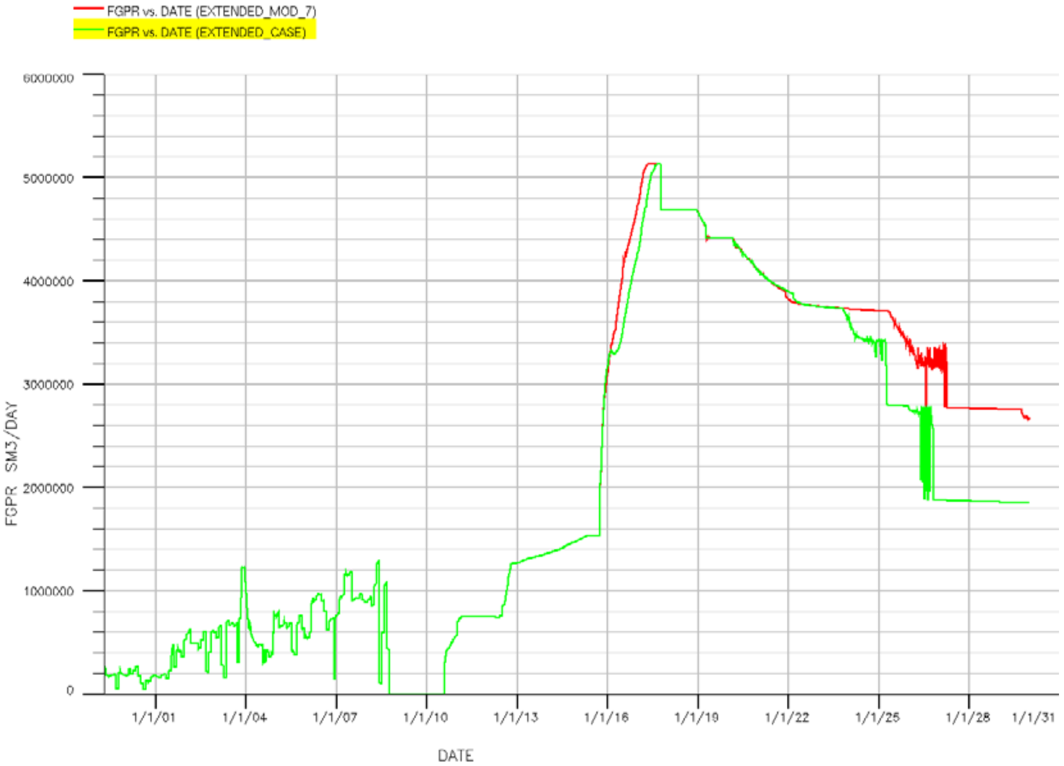
Field Oil Production Rate (FOPR)



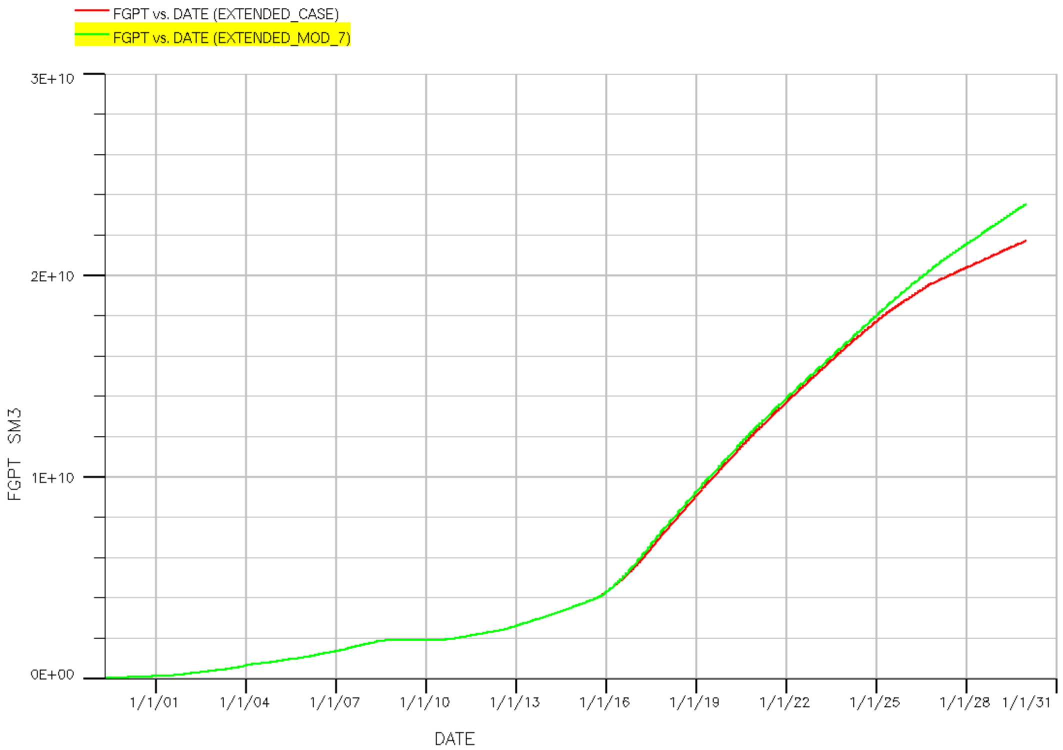
Field Oil Production Total (FOPT)



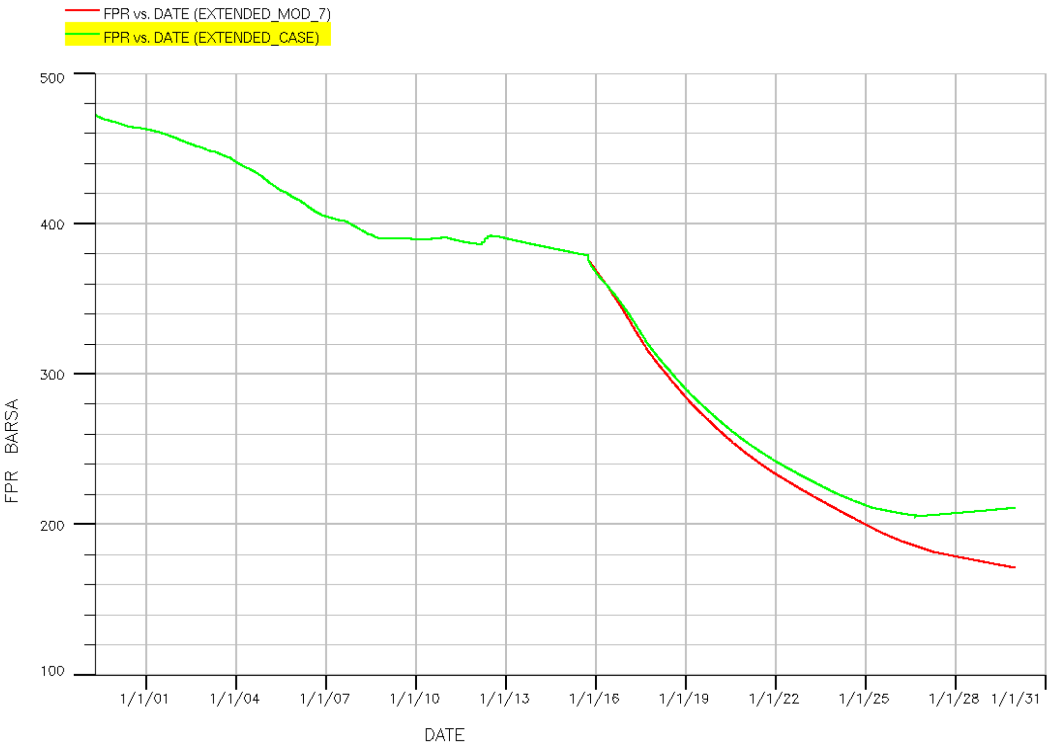
Field Gas Production Rate (FGPR)



Field Gas Production Total (FGPT)

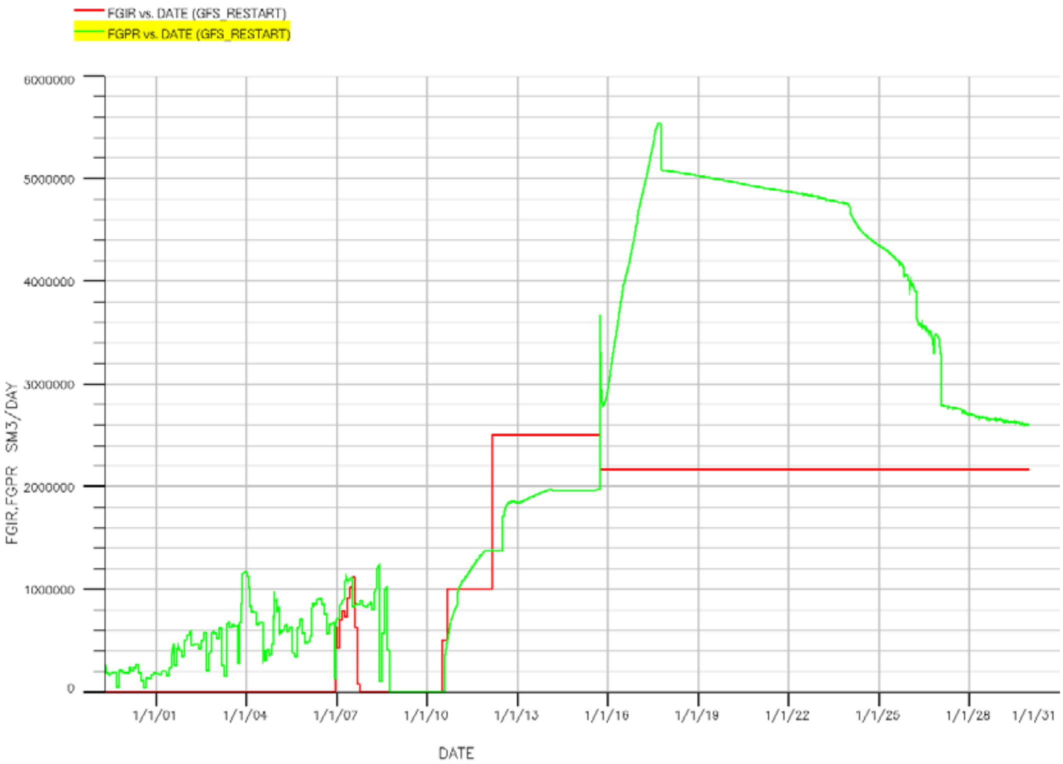


Field Pressure

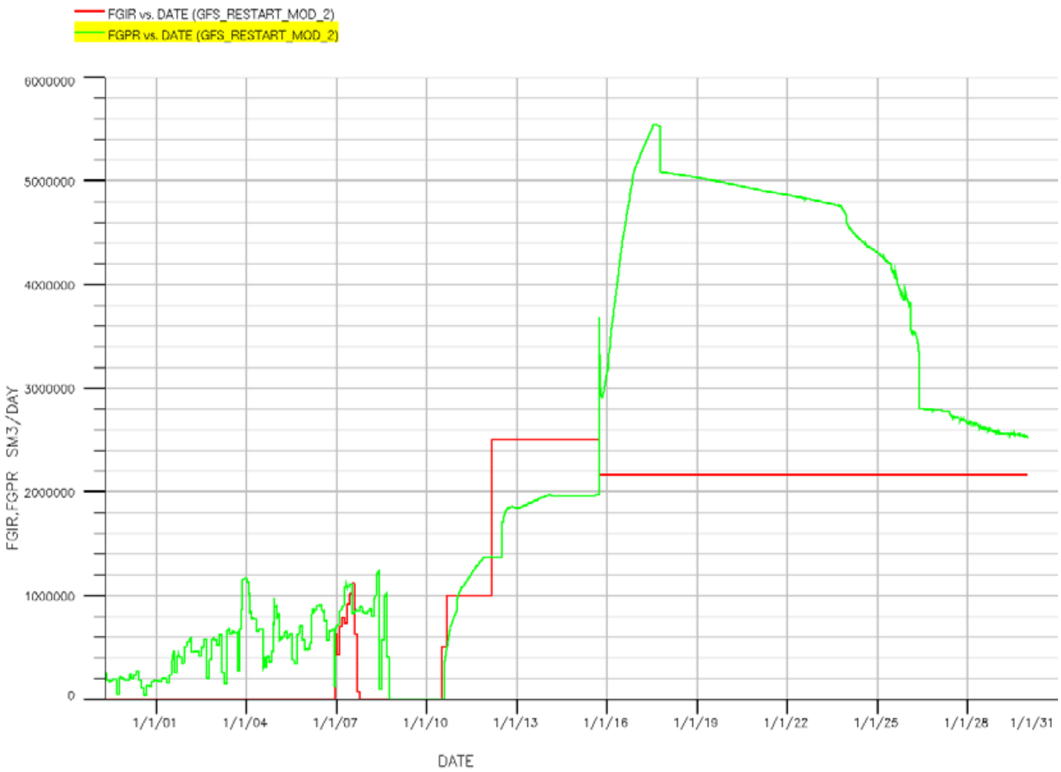


Appendix D: Field Gas Injection vs Gas Production Charts

GFS_RESTART



GFS_RESTART_MOD_2



EXTENDED_CASE_9