NTNU – Trondheim
Norwegian University of
Science and Technology

Optimization of the Norne FPSO production using Reservoir Coupling in Eclipse

Kristine Arntzen

Earth Sciences and Petroleum Engineering
Submission date: June 2012
Supervisor: Jon Kleppe, IPT
Co-supervisor: Sindre Lillehaug, Statoil Harstad

Norwegian University of Science and Technology
Department of Petroleum Engineering and Applied Geophysics

SAMMENDRAG

Seks reservoarer produserer i dag til Norneskipet. I løpet av fire neste årene, vil to nye reservoarer bli tilknyttet skipet og satt i produksjon. Dette vil føre til at de totale produksjonsratene vil overskride de tilgjengelige kapasitetene på prosessanleggene. For å hindre at dette skjer må produksjonen strupes.

I denne masteroppgaven er hovedfokuset å optimere hydrokarbonproduksjonen for alle feltene som produserer til Norneskipet, innenfor de tilgjengelige kapasitetene på vann- og gassprosesseringsanleggene. Dette vil bli gjort ved hjelp av reservoarsimulatoren Eclipse 100.

Først vil det ved hjelp av Urd simuleringsmodell bli gjort en sensitivitets analyse for bruk av gassløft.

Videre er det utforsket hvilke muligheter som finnes i Eclipse når det gjelder struping av produksjon. Tre metoder er valgt ut og forklart i detalj. Disse er:

i) Fraksjonsmetoden
ii) Bruk av Guide Rates
iii) Bruk av Prioriteringsregler

For å observere de totale produksjonsratene, og kunne prioritere bruk av prosessanleggene mellom de reservoarene som produserer til Norneskipet, er Reservoar Kopling (RK) fasiliteten i Eclipse brukt, i kombinasjon med Eclipse optimerings verktøy. Den simulerte hydrokarbonproduksjonen er optimert på to måter:

i) Ved å strupe brønner med høyt vannkutt på Norne

ii) Ved å favorisere gassproduksjon fra Alve over bruk av gass løft på Urd

Resultatene fra RK-modellen har indikert at det er mulig å strupe vannproduksjonen på Norne hovedfelt, minimere gassløft på Urd og samtidig opprettholde den totale oljeproduksjonen.

Denne oppgaven har som hensikt å vise at er det viktig å ha en god produksjonsstrategi for å optimere hydrokarbonproduksjonen på et felt.

ABSTRACT

Six reservoirs are currently producing to the Norne Floating Producing Storage Offloading (FPSO) vessel. Over the next four years, two new reservoirs will be tied back to the ship. The total production potential of liquid, water and gas is expected to exceed the available capacity of the surface facilities. In order to honor the processing constraints using the existing facilities, the production needs to be choked.

In this thesis, the main focus was to optimize the oil and gas production on the Norne FPSO within the available capacities of water treatment and gas processing, using the commercial reservoir simulator Eclipse 100.

A sensitivity analysis for the use of gas lift has been carried out, using the Urd stand-alone model.

The alternatives of choking the production in Eclipse were also studied. Three methods are explained in detail and applied to the Norne stand-alone model. These are:

i) The Fraction Method
ii) Use of Guide Rates
iii) Use of Priority Rules

To observe the overall production rates, and prioritize the usage of the process facility between fields that are producing to the Norne FPSO, the Reservoir Coupling (RC) facility in Eclipse was used, in contraction with Eclipse optimization tools. The simulated hydrocarbon production is maximized in two ways:

i) By choking the high Water Cut (WC) wells on Norne
ii) By favoring Alve gas production over gas lift usage on high WC producers on Urd

The results from the RC model indicate that it is possible to constrain the water production on Norne, minimize the gas lift on Urd, and at the same time maintain the oil production rate.

Above all, this thesis has intended to show that it is important to employ a good production strategy to optimize the hydrocarbon recovery.

PREFACE

This thesis is carried out at the Norwegian University of Science and Technology (NTNU), Department of Petroleum Engineering and Applied Geophysics, and completes a five year Master in Science.

The thesis was written at the Statoil office in Harstad, with Sindre Lillehaug- Reservoir Engineer at Skrugard/Havis, as academic adviser.

Professor Jon Kleppe - Professor in Reservoir Engineering and Head of the Department for Petroleum Engineering and Applied Geophysics at NTNU, has also contributed with advice and guidance throughout this thesis.

The work was conducted between the 16th of January and the 8th of June, 2012, and the main goal was to optimize the Norne FPSO hydrocarbon production using reservoir coupling in Eclipse.

Writing this thesis has been interesting and challenging, and the author has learned a lot about the complexity of a hydrocarbon optimization problem.

Trondheim, June 2012

Kristine Arntzen
kriar@statoil.com

ACKNOWLEDGMENT

First of all, I would like to thank my supervisor at Statoil, Sindre Lillehaug – the Reservoir Engineer at Skrugard/Havis. He has previously worked as the leading Reservoir Engineer on Norne. Along with being a great person, Sindre has a particular interest in production optimization and he has helped and supported me throughout this thesis.

I would also like to thank my supervisor at NTNU, Professor Jon Kleppe - Professor in Reservoir Engineering and Head of the Department for Petroleum Engineering and Applied Geophysics at NTNU.

Further, I would like to thank my family, without their support and encouragement I would not have been where I am today.

Last but not least I need to thank Statoil for creating a unique work environment allowing students to work on real data.

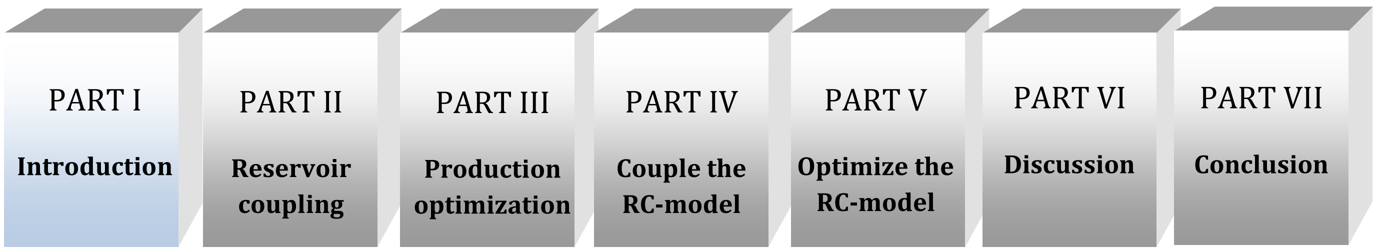
CONTENTS

LIST OF FIGURES

LIST OF TABLES

PART I

INTRODUCTION



In Part I, Introduction, a presentation of the motivation for this thesis will be given. The main goals will be stated, and the strategy to achieve these goals will be provided.

Further, an introduction to the history of the Norne field will be given. The importance of the new discoveries around the main field will be clarified, and each of the eight reservoirs that are going to produce to the Norne FPSO will be described.

There will also be a short introduction to the simulation models used for each reservoir.

Commercial agreements, that complicate the optimization problem, will be discussed briefly.

Finally, since all the reservoirs are producing to the Norne FPSO, the capacities of the surface facilities will be given.

1.1 Background

In many mature fields, the hydrocarbon production is constrained by the capacities of the surface facilities.

On the Norwegian shelf, a common production strategy is to have several reservoirs producing to the same facilities. The available capacities on the process plant are shared among the field owners, controlled by commercial agreements (see subchapter 1.3).

When new reservoirs are found nearby a field that is already producing, they are normally tied back to the existing facilities. This leads to increased production rates. The capacities of water treatment, fluid capacity, water injection and gas processing will most likely be exceeded.

One field that is constrained by the process capacity is the Norne Field. Norne is located in the North Sea, and six reservoirs are currently producing to the facilities on the Norne Floating Producing Storage Offloading (FPSO). These reservoirs are Norne, Svale, Stær, Alve (Garn/Not), Alve (Tilje) and Marulk.

Over the next four years, it is planned to recruit two new reservoirs to the ship. These are Fossekall and Dompap. When these reservoirs start producing, the total production rates will exceed the available capacities on the water and gas processing plant (see subchapter 1.4).

There are two ways of handling the "capacity constraint". Facility expansion may be one alternative to increase the production rates. But this may not be the optimal choice. An economic alternative is to optimize the use of the already existing production facilities. (Wang, P., Aziz, K. and Litvak, L. M, 2002)

In production optimization, the goal is to find the best operational settings at a given time, to get the highest hydrocarbon production rate. The way this is done may vary. For example, it could be to maximize the oil production, minimize the gas/oil rate or reduce the production costs.

In the literature, different methods of optimizing the hydrocarbon production for fields with different ownerships and commercial interests are documented; see Haavardson and Huseby (2010)

In this thesis, the main focus is to optimize the hydrocarbon production on the Norne FPSO using Reservoir Coupling (RC) in Eclipse.

On the Norne FPSO, Several different fields are using the same gas processing plant, and the capacity is limited. By optimizing the usage of the plant, it is possible to increase the gas production rates. One way of doing this, is to use less gas lift on Urd, and let Alve produce more.

When new reservoirs are tied to the Norne FPSO, the water treatment capacity of 30 000 Sm3/day is exceeded. In order to honor the constraints using the existing facilities, the production needs to be choked.

First, a sensitivity analysis for the use of gas lift has been carried out, using the Urd stand-alone model.

Then, the alternatives of choking the production in Eclipse were studied. Three methods are explained in detail and applied to the Norne stand-alone model. These are

i) The Fraction Method
ii) Use of Guide Rates
iii) Use of Priority Rules

To observe the overall production rates, and prioritize the usage of the process facility between fields that are producing to the Norne FPSO, the Reservoir Coupling (RC) facility in Eclipse was used, in contraction with Eclipse optimization tools. The simulated hydrocarbon production is maximized in two ways:

i) By choking the high Water Cut (WC) wells on Norne
ii) By favoring Alve gas production over gas lift usage on high WC producers on Urd

1.2 NORNE AND THE SATELLITES

The Norne main field and the satellites Urd, Alve, Marulk and Skuld are located in the Nordland II area; about 80 kilometers north of Heidrun, see Figure 1. It is currently the northernmost developed field in the Norwegian Sea.

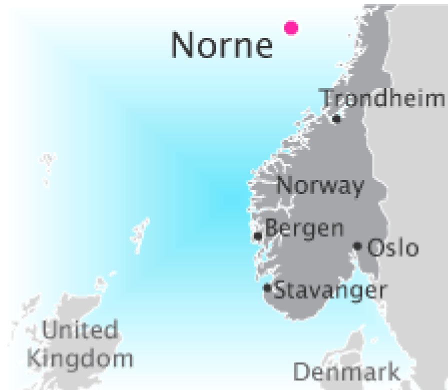


Figure 1 - Location of Norne and the satellites (Statoil ASA)

The field is operated from Harstad, and it is producing to the Norne FPSO.

Today, six reservoirs are producing to the ship. These are the Norne main field, Svale, Stær, Alve (Garn/Not), Alve (Tilje) and Marulk. Over the next four years, it is planned to connect two new reservoirs to the ship. These are Fossekall and Dompap. All of the reservoirs are producing to the same surface facilities, but the facility capacities are limited.

Due to the new discoveries around the main field, Norne's lifetime is extended from 2016 to 2021. The plan is to extend it even further to 2030.

An overview of the number of templates, producers, injectors and original recoverable reserves for each field, as reported by the Norwegian Petroleum Directorate (NPD) the 31st December 2011, can be found in Table 1.

Table 1- Original recoverable and produced reserves reported by NPD 31.12.2011

Field	Norne	Urd	Alve	Marulk	Skuld
Reservoirs	1	2	2	1	2
Hydrocarbons	Oil/gas	Oil	Oil/Gas	Gas	Oil
Templates	7	3	1	1	3
Active producers	13	5	2	2	0
Active injectors	8	3	0	0	0
Org. Rec reserves					
Oil [mill Sm3]	90.80	6.60	1.40	0.70	13.4
Gas [mrd Sm3]	11.80	0.10	5.10	8.40	0.90
Prod. Rec. Reserves					
Oil [mill Sm3]	86.20	4.70	0.80	Start 01.04.2012	Start 01.12.2012
Gas [mrd Sm3]	6.40	0.10	2.50	--	--
Oil [%]	94.9	71.2	57.1	--	--

1.2.1 NORNE MAIN FIELD

The Norne main field was discovered in December 1991. The reservoir consists of two separate oil parts, the Norne main structure (C-, D-, and E-segment) and the G-segment located northeast of the main structure, see Figure 2.

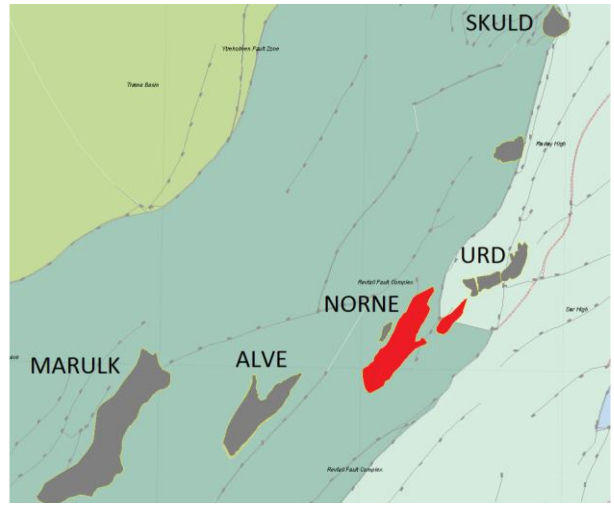


Figure 2- Location of the Norne Main Field (NPD)

The reservoir was found in Jurassic sandstones at about 2500 meters depth, and the exploration well 6608/10-2 proved a hydrocarbon bearing column of 135 meters in the main structure, where 110 meter is an oil column and the remaining 25 meters is an overlying gas cap. The field is made up of the formations: Garn, Not, Ile, Tofte and Tilje. Initially, the oil was located in the Ile and Tofte formations, with an aquifer located in the Tilje formation and below (Morell, 2010). Today, Tofte and partly the lower Ile formation are drained, and the remaining oil is located in the upper Ile formation. The reservoir quality is generally good, but faults, carbonate cemented layers and the clay-rich Not formation have a significant influence on the flow pattern.

The reservoir was originally developed with five subsea templates, three templates for production, one template for injection and the last one is a combined production/injection template. Two new templates have later been installed (K- and M- template). The production stream is carried through flexible risers back to the ship. The gas export from Norne to Kårstø started in 2001. Until then, the gas was re-injected into the reservoir. The main drainage strategy of the reservoir is water injection.

Today there are 13 active producers and 8 active injectors on Norne. The Norwegian Petroleum Directorate (NPD) reports that 94.9 % of the recoverable reserves have already been produced, see Table 1.

Simulation Model

The Norne simulation model is represented by a 55x136x32 grid system, shown in Figure 3. The porosity ranges from 24% - 28 % and the permeability range from 100 mD to 1000 mD. The model was updated and history matched in April 2009.

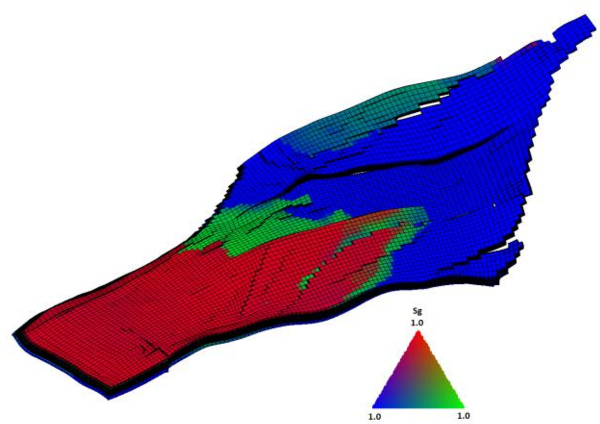


Figure 3- The Norne simulation model

1.2.2 URD

Urd is a satellite of Norne, and consists of the two oil deposits, Svale and Stær.

Svale was discovered in the spring of year 2000, and it is located ten kilometers northeast of Norne, see Figure 4. First, the geologists indicated a recoverable volume of up to 15 MSm3 with oil, but the volume was later reduced to 6.8 MSm3. Due to high construction costs, and an overestimation of the recoverable volume, Statoil decided to stop the planning of the project, late autumn 2001.

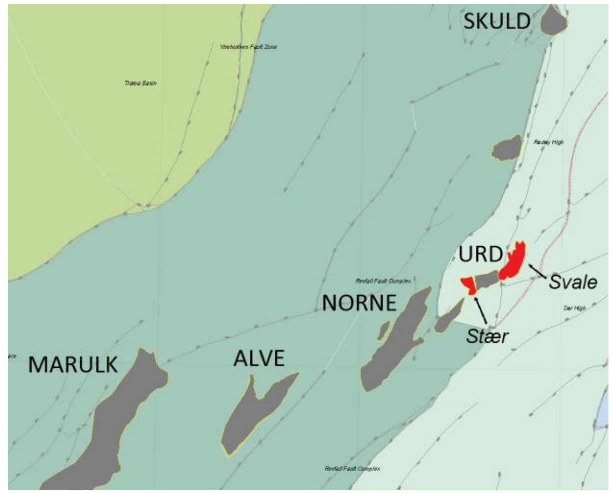


Figure 4- Location of the Urd field (NPD)

In the spring of 2002, Statoil discovered Stær, a hydrocarbon filled structure located approximately five kilometers northeast of Norne, see Figure 4. The project was resumed, and the plan for development and operation (PDO) for Urd was approved in 2004.

Urd is developed with subsea templates, and the production started in November 2005. Today, Svale is producing with three oil producers and two water injectors, while Stær is producing with two oil producers and one water injector. The reservoirs are located at 1800-2300 meters depth, and consist of Lower to Middle Jurassic sandstones. The oil on Svale is heavy, viscous and undersaturated. Therefore, gas lift is used to reduce the well stream density, and increase the production.

The production steam from Svale is sent to Stær, via a five km long pipeline. Then the total production from the two reservoirs is sent through a single pipeline, to the Norne FPSO for processing. According to Table 1, 71.2 % of the recoverable reserves have been produced.

Simulation models

The Svale simulation model is represented by a 100 x 60 x 59 grid system, shown in Figure 5. The porosity ranges from 14% - 33 % and the permeability range from 2 mD to 8500 mD. The model is history matched to January 2010. The Stær model does not match the actual field production. Therefore the profiles of these wells are entered manually in the schedule section of the Eclipse data file.

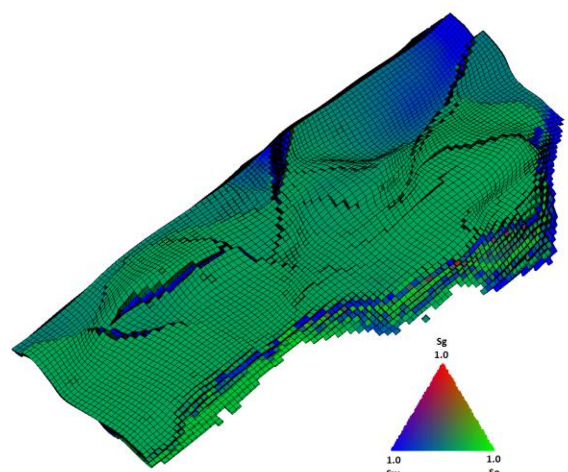


Figure 5- The Svale simulation model

1.2.3 ALVE

Alve was discovered in 1990, and is located about 16 kilometers southwest of Norne, as shown in Figure 6. It was this find that lead to the discovery of Norne.

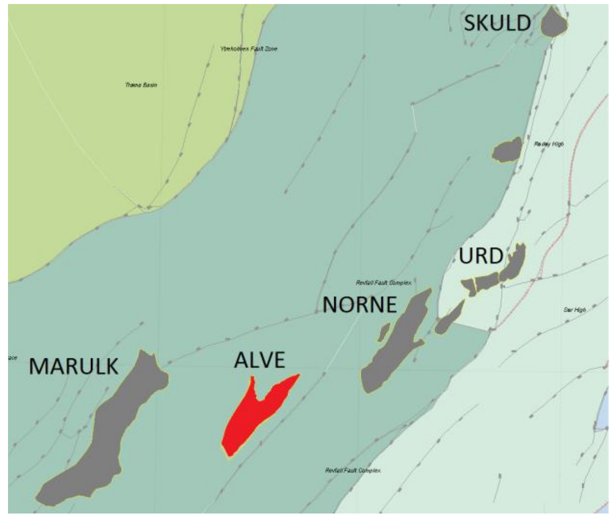


Figure 6- Location of the Alve field (NPD)

The plan was to develop Alve with a gas well in the Garn/Not formations, with a 75% possibility of an oil discovery in the Tilje formation, deeper down. A conventional subsea solution has been used, and four slots are available.

In 2008, a combined exploration/production well was drilled in the Garn/Not formation and the well came on stream in March 2009. Production from the gas reservoir on Alve will ensure a continuous use of the free gas capacity on the Norne ship.

In February 2011, another exploration/production well was completed in the oil zone in the Tilje formation, proving an oil column of 38 m.

Estimates from NPD shows that 57.1% of the recoverable reserves have been produced, see Table 1, and the recovery strategy is pressure depletion.

Simulation models

The Alve model is made up of two separate simulation models, coupled together. One model represents the gas reservoir, while the other model represents the oil reservoir.

The model for the gas reservoir is shown in Figure 7. It is represented by a 152x53x44 grid system, where the porosity ranges from 8%-26% and the permeability ranges from 3mD to 1500mD.

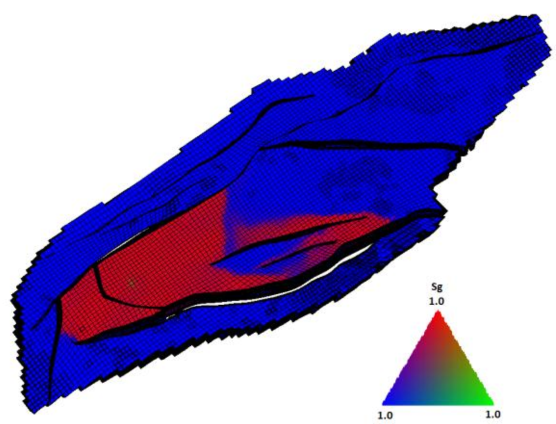


Figure 7- The Alve simulation model

1.2.4 MARULK

Marulk was discovered in 1992 and is a gas and condensate field located roughly 30km southwest of Norne, at a water depth of approximately 370 meters, see Figure 8.
The operator is Eni Norge, and Marulk is the very first field that the company is operating on the Norwegian shelf.

The reservoir consists of the two formations - Lysing and Lange, but the planned development of the field is only based on production from the Lysing formation.

The plan is to produce the field with two wells, and the recovery strategy is pressure depletion.

The gas is transported by a 30 km long pipeline, back to the Norne FPSO for processing, as shown in Figure 9. The pipeline and the control cable for the transport of hydraulic fluid, and chemicals from the Norne FPSO to Marulk, are taking place via the templates on Alve.

Marulk came on stream 2nd April, 2012 and has an expected lifetime of 10 years.

Simulation model
Since the operator of Marulk is Eni, Statoil does not have an updated simulation model for the field.

Therefore, the production profiles of the Marulk field are entered manually into the schedule section of the Eclipse data file.

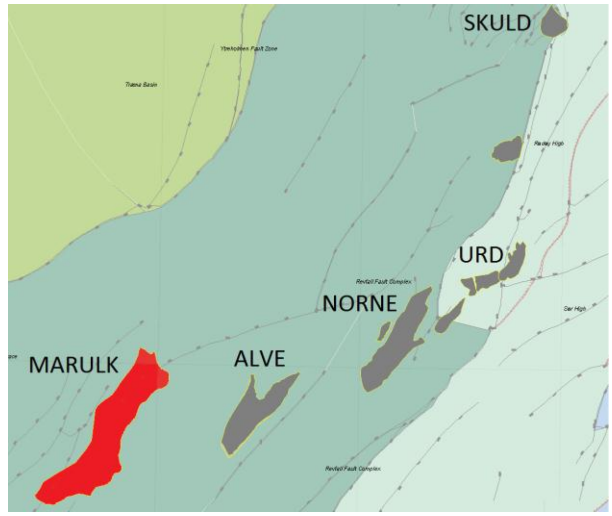


Figure 8- The location of the Marulk field (NPD)

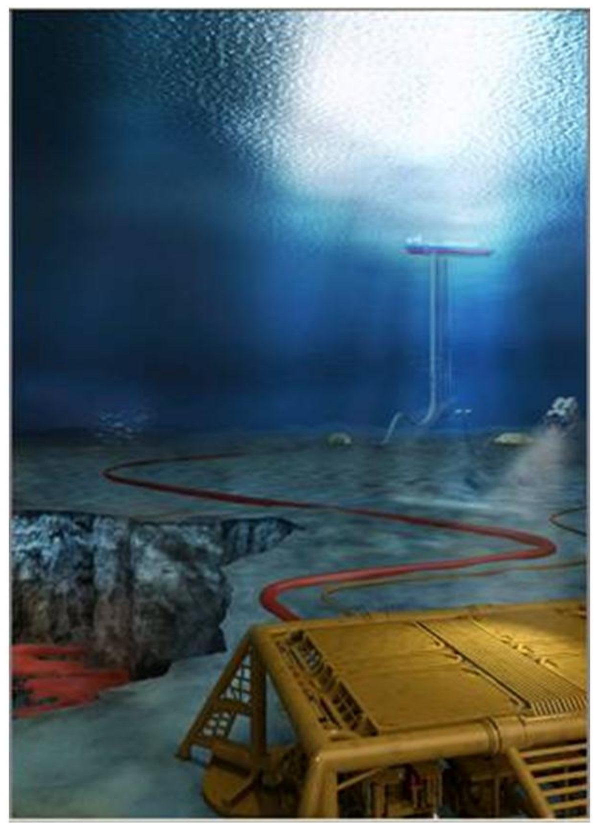


Figure 9 - The gas export pipeline from Marulk to the Norne FPSO (Enig Norge)

1.2.5 Skuld

Skuld consists of the two oil deposits, Fossekall and Dompap, located 16 km and 26 km northeast of the Norne main field, shown in Figure 10.

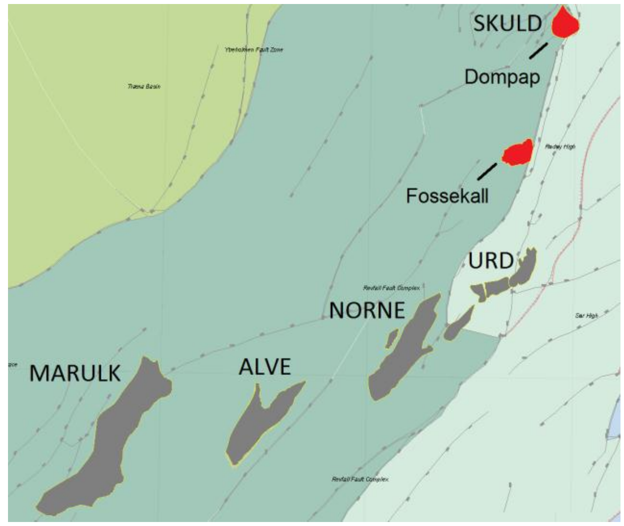


Figure 10- The location of the Skuld field (NPD)

Dompap was discovered in 2009, with an exploration well proving a 110 m high oil column in the Åre formation.

In 2010, the Fossekall oil deposit was found. Here, the exploration well proved oil in the Åre formation, as well as in the Ile and Tofte formations, and gas in the Melke formation.

The PDO was approved 20th January 2012 and the production will start in December 2012. Due to the short time between the PDO approval and the production startup, Skuld is a "fast-track"- development, the largest in Statoil so far. Skuld is expected to account for more than half of the production from fast-track projects in Statoil in 2014.

The plan is to develop the field with three standard subsea templates, with a total of six production wells and three water injectors. The production stream will be sent back to the Norne ship for processing, through a 14-inch production flow line and 11-inch flexible riser.

Simulation models

Each of the two reservoirs has their own independent simulation model. Since they are sharing the same pipeline, the two models are coupled together.

The Dompap simulation model is shown in Figure 11. This model is represented with a 90x130x83 grid system.

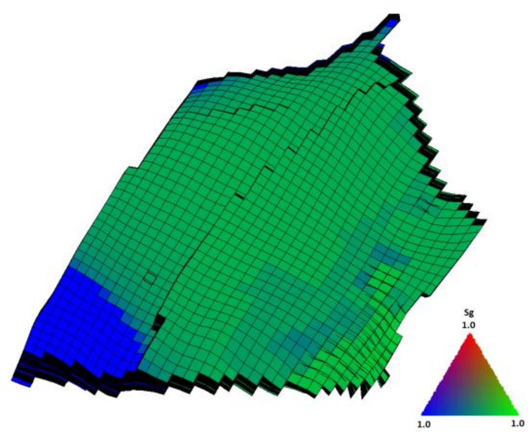


Figure 11 - The Dompap simulation model

1.3 COMMERCIAL AGREEMENTS

The Norwegian government believes that competition and cooperation between companies is important to get the maximum value from the oil and gas resources. Therefore, a model has been created for the activity on the Norwegian shelf. This model divides the shelf into several blocks, and each block is organized in production licenses where multiple companies are working together as co-owners.

Due to this Norwegian model, the reservoirs that are producing to the Norne FPSO have different ownerships, shown in Table 2. Since Eni Norge AS owns a higher shear of Urd than of Norne; they will make more money on one bbl oil produced from Urd than one bbl oil produced from Norne.

Therefore, it is in Eni's interests to produce as much as possible from the Urd wells, even though this will not optimize the overall oil production at the Norne FPSO.

Since the fields have several owners, and all the reservoirs are producing to the same surface facilities, the available capacities need to be shared.

Table 2 – Field ownership overview

Partners		
Norne		
Petoro AS	54.0	%
Statoil	39.1	%
Eni Norge AS	6.9	%
Urd		
Statoil	64.0	%
Petoro AS	24.5	%
Eni Norge AS	11.5	%
Alve		
Statoil	85.0	%
Dong E&P Norge	15.0	%
Marulk		
Eni Norge AS	20.0	%
Dong E&P Norge	30.0	%
Statoil	50.0	%
Skuld		
Statoil	64.0	%
Petoro AS	24.5	%
Eni Norge AS	11.5	%

Commercial agreements have been made to handle these sorts for problems. These agreements need to be taken into consideration during the optimization of the oil production.

1.4 SURFACE FACILITIES

The Norne field is developed with a Floating Production Storage and Offloading vessel, the Norne FPSO, see Figure 12. When the ship was built, it was the largest monohull production vessel in the world. It had the capacity of producing 27500 Sm3/d of oil.

The topside was designed to meet the capacities described in Table 3. Already before the ship was built, there were knowledge about possible spare capacity on the facilities, in case satellite fields in the area where tied to the ship. The plan was that these fields could be phased in when the production of the Norne main field was declining (Adam, 1995).

Table 3 – Topside design Norne FPSO

Topside design Norne FPSO (May 1995)	
Oil production	27500 Sm3/d
Water production	35000 Sm3/d
Gas production	7.0 mill. Sm3/d
gas re-injection	6.7 mill. Sm3/d
Water injection	40 000 Sm3/d
Offloading capacity	8000 m3/h
Oil storage volume	115 150 m3
Living quarters	120 persons

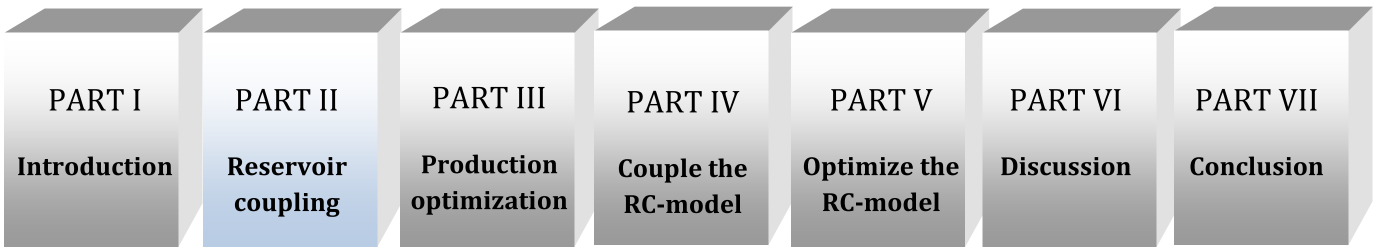
The production flow is sent from the reservoir, through a pipeline and a flexible riser, to the ship for processing. The inlet separator at the ship operates at 20-25 bars. At the inlet separator, the oil, gas and water are separated.

The theoretical water handling capacity of the Norne FPSO is 35 000 Sm3/day. However, in recent tests the actual capacity was found to be 30 000 Sm3/day. Therefore, in this thesis, 30 000 Sm3/ day has been used as the maximum limit.

Figure 12 - The Norne FPSO (Statoil ASA)

PART II

ECLIPSE RESERVOIR COUPLING



In Part II, an introduction to the Reservoir Coupling facility in Eclipse will be given. The importance and advantages with this feature is also presented.

The Network Option in Eclipse will also be described, focusing on the Extended Network Option, which this is used in the simulation model.

There will also be a short introduction to master and slave reservoirs, which is used when building a Coupled Model.

2.1 INTRODUCTION TO RESERVOIR COUPLING

Imagine an area that contains a number of separate reservoirs. There is a simulation model to each reservoir, and each model is history-matched independently. The reservoirs may have different characteristics; some reservoirs contain oil or gas, while others may be a mixture of oil and gas.

Since the simulation models try to reflect the reservoir in the best possible way, they are using different options in Eclipse. For example, some may be three-phase models, while others are two-phase models.

The plan is to produce these reservoirs into common surface facilities.

Without RC, the above scenario would require the various simulation grids to be merged into one huge model. If one of the simulation models uses three-phases, the amalgamated model would also have to use it. It would be time consuming to merge the models, and the resulting model is slow and expensive to run.

An efficient solution to this problem is the RC facility in Eclipse. This option allows each reservoir to be represented by their original simulations model, meaning each having its own standard Eclipse data file. Then, one of the models is chosen to be the “master”, while all the other models are defined as “slaves”. The master activates the slave processes, and imposes production and injection constraints on the slaves to meet overall targets.

The master and the slaves are run in synchronization with each other. In some cases, the slave processes may be run in parallel with each other on separate workstations, to save time. (Eclipse Technical description, 2011)

There are three main advantages using RC.

First, when several reservoirs are producing to the same flow line, it is possible to dynamically calculate the wellhead pressures for each reservoir.

Second, when several reservoirs are sharing the same facilities, and the capacities are limited, it is possible to prioritize which fields that are going to use the available capacity.

Thirdly, RC allows the user to make combined production plots.

2.2 NETWORK OPTIONS

To get a better understanding of how RC works, the user needs to take a closer look at the Network Option in Eclipse. This option allows the user to build a hierarchy, showing the hydrocarbon path from the reservoir, up to the separator or stock tank.

This works as follows; a group of wells connected to the same manifold passes the production flow through a pipeline, to the next group (parent group) in the hierarchy. This group gathers the production from a number of well manifolds, and sends it along another pipeline, to its own parent group. This routine is repeated, until a group with a fixed-pressure separator or stock tank is encountered.

In Figure 13, the group called GR-A1 is a well group, and PLAT-A is its parent group. The group PLAT-A gathers the production the two well manifolds, GR-A1 and GR-A2, then sending it further to its own parent group (FIELD).

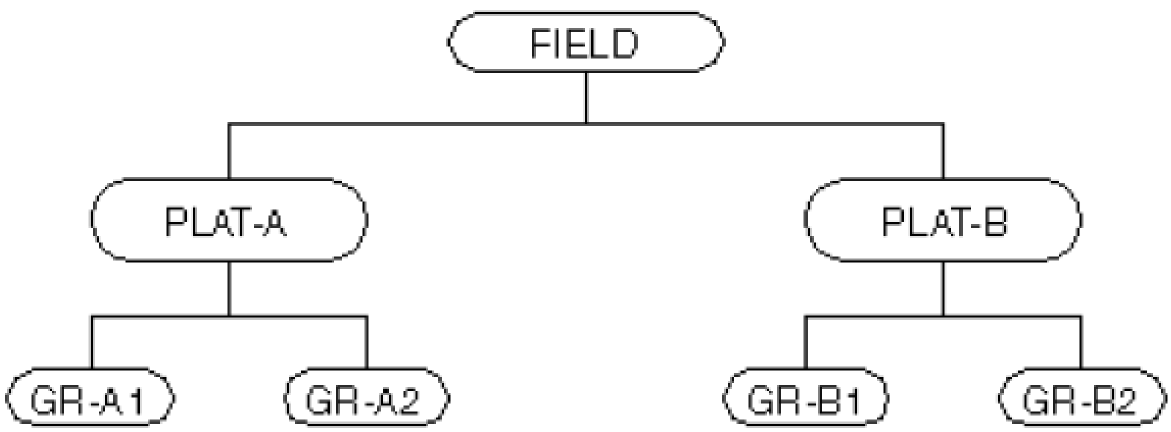


Figure 13- A network hierarchy (Eclipse Technical description, 2011)

Each group in the network is called a "node". The group at the top of the hierarchy, containing the separator, is a "fixed- pressure node". The groups subordinate to the fixed-pressure node has their own "nodal-pressures".

These nodal pressures are determined from the pipeline pressure losses, depending on the rates and fluid ratios only.

There are two possible ways of defining the network in Eclipse; the Standard Network Option and the Extended Network Option. In this thesis the Extended Network option is used.

2.2.1 EXTENDED NETWORK OPTION

With the Extended Network Option, it is possible to apply production targets or upper limits to any group in the network. If a well cannot produce at its allocated rate target, it will produce as much as it can under its own flow and pressure limits, while the remaining wells under group control make up the rest of the group's flow target.

This makes it is more versatile than the Standard option, where the production targets or upper limits only can be applied to well-groups. A "well-group" is a group containing wells.

The Extended Network Option also provides a more flexible handling of well and group downtime, and it is possible to remove a specified rate or fraction, of the water flowing through a node.

2.3 MASTER AND SLAVE RESERVOIRS

When coupling several reservoirs together, the user need to define one master and one or more slave reservoirs. Each slave reservoir has its own Eclipse data file. Restart files can be included, if required. The master is an additional simulation model and it can represent one of the reservoirs to be simulated. An alternative is to represent all the reservoirs as slave reservoirs, and let the master reservoir be a dummy reservoir, for example containing one single grid block.

The communication paths between the master and the slaves go through specified groups in the network hierarchy. In the slave reservoir, these groups must be defined under the keyword GRUPSLAV, while the same groups are defined under the keyword GRUPMAST in the master reservoir.

The master reservoir must contain the group hierarchy of the whole system, down to the slave groups in the slave reservoir. The master groups have no subordinate wells or groups in the master data file, while the slave groups may contain one or more wells. (Eclipse Technical description, 2011)

Figure 14 shows three reservoirs that are coupled together. Here, the master reservoir is a dummy reservoir and the white boxes represent the master groups. Each master group is represented in a slave reservoir, but since the Extended Network Option is used, the names do not have to be the same.

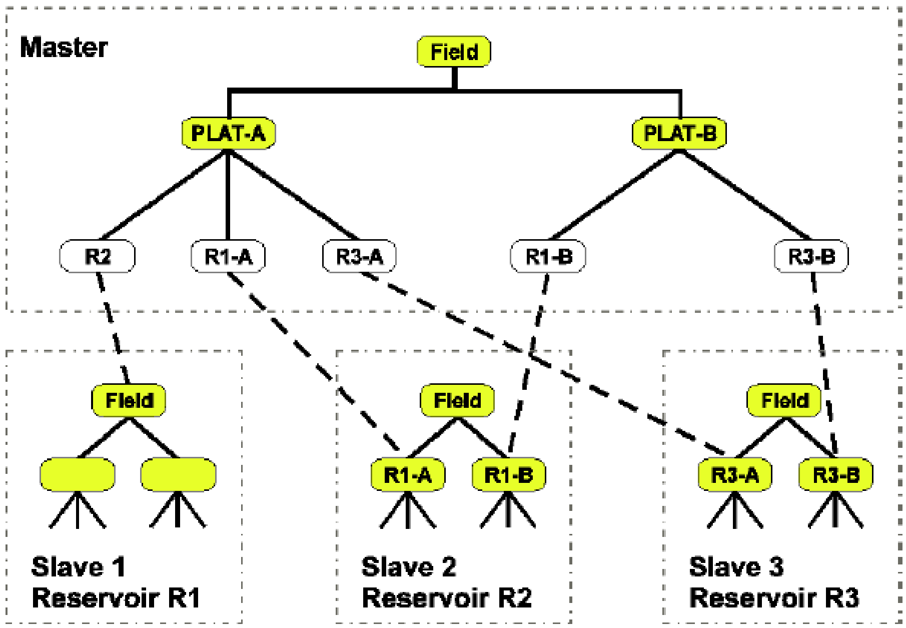


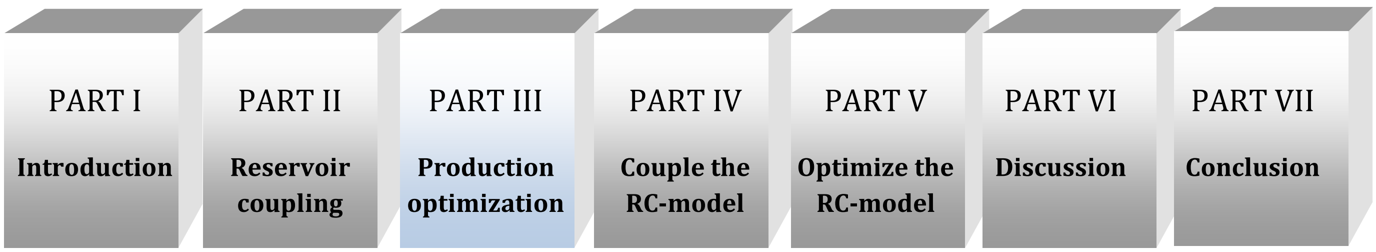
Figure 14- Three coupled reservoirs (Eclipse Technical description, 2011)

When the master run starts, it enquires the start date of each slave run. If the slave has a start date later than the master, this will be "dominant", and the slave will not contribute any production or injection, until its start date is reached in the master run.

A step by step procedure, of how the master and the slave runs are synchronized with each time step of the master run, can be found in the Eclipse Technical description.

PART III

OPTIMIZATION OF THE HYDROCARBON PRODUCTION



In Part III, Optimization of the hydrocarbon production, the purpose of production optimization will be presented.

Further, the complexity of gas lift optimization will be explained, and the Gas Lift Optimization facility in Eclipse will be presented.

To honor the surface capacities on the Norne FPSO, the production needs to be choked. Therefore, the key elements using production control in Eclipse, is explained. Three alternatives of choking the production will also be described. These are:

1. The Fraction Method
2. Guide Rates
3. Priority Rules

3.1 PRODUCTION OPTIMIZATION

In production optimization, the goal is to find the best operational settings at a given time, to get the highest hydrocarbon production rate. There are several ways to reach this goal. One way could be to maximize the oil production, minimize the gas/oil rate, or reduce the production costs.

Because the capacities on the processing plant are limited, it is important to make optimal use of the existing facilities. It might be necessary to choke the production, in order to honor the capacity constraint.

3.2 USE OF GAS LIFT

In reservoirs where the oil is heavy and viscous, and the pressure in the reservoir is too low to lift the flow out of the wellbore, gas is usually injected. The gas reduces the density of the production stream and makes it easier to flow. As a result of this the production rate may increase.

The main drawback of using gas lift is that it occupies space on the gas process plant. By releasing this space, more gas could be sold.

Eclipse provides a Gas Lift Optimization Facility. With this option it is possible to assign a well just enough gas to keep it flowing. In addition, it can solve the following problems:

1. Optimize the gas lift of an individual well

2. Optimize the gas lift for a group of wells

3. Optimize the gas lift within a simple network

Optimize the gas lift of an individual well
The production rate of a well under THP control will first increase when the supply of gas lift is increased. This is due to the reduced density of the production stream in the wellbore, see Figure 15.

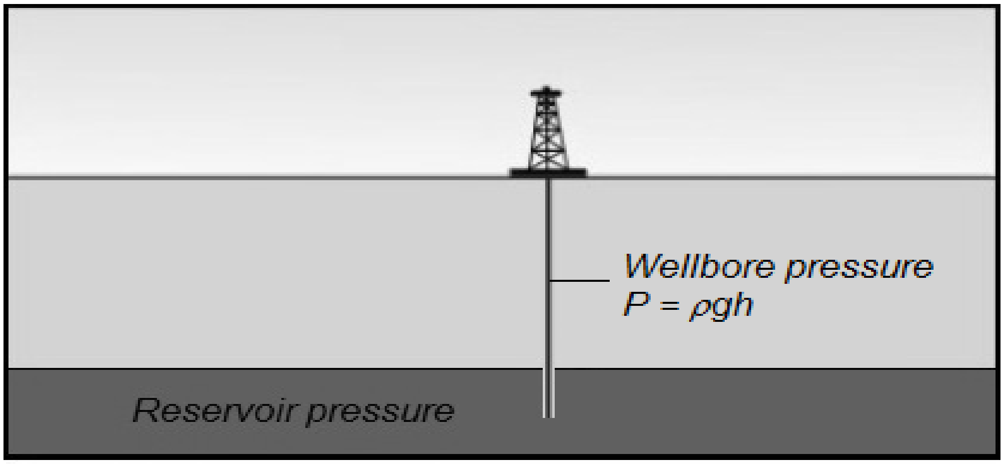


Figure 15 - Density influence on the wellbore pressure for a vertical well (free after geology.com)

But as the supply of gas lift is increased further, the pressure losses due to friction become more important. Therefore, the production rate peaks then starts to decrease, as shown in Figure 16, Point A.

Injecting gas is expensive, and there is a trade-off between the cost of compress a rate unit of lift gas (for example Msm3/day) and the value of the extra amount of oil produced. This balance can be described as the optimal Gas Lift injection Rate (GLIR) and is shown as point B in Figure 16. (Eclipse Technical Description, 2011)

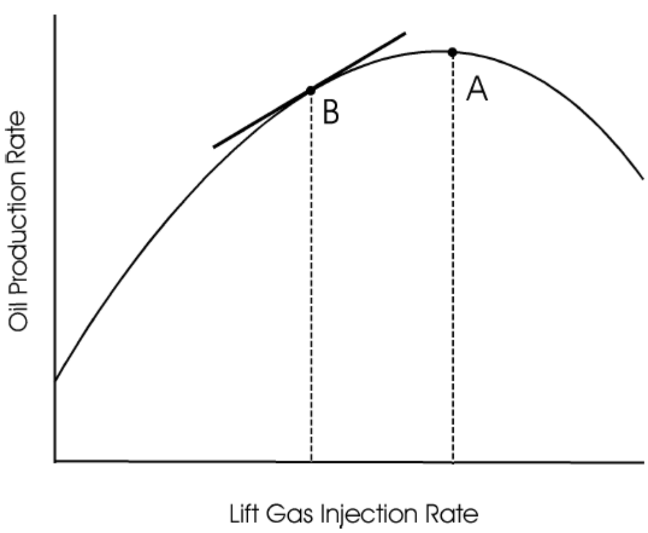


Figure 16 - Gas lift rate influence on the oil production (Eclipse Technical Description, 2011)

Optimize the gas lift within a simple network

If the well is sharing the flow line with other wells, and the Network Option is used, the optimization problem becomes more complicated. A slight increase in gas lift to one particular well may lead to an increase in the well's flow rate, but this will also increase the tubing head pressure of all the other wells in the group. The additional lift gas will create an extra pressure drop in the pipeline and this may cancel out the extra production from the well (Eclipse Technical Description, 2011).

As shown, gas lift optimization is a very complex problem.

Another way of optimizing the hydrocarbon production is to optimize the usage of the gas process plant, between the fields that are sharing the same facilities. In this thesis, the Gas Lift Optimization facility will be used on Urd simulation model, to minimize the gas lift. This will release space on the gas process plant, giving other gas reservoirs the opportunity to produce more.

3.3 PRODUCTION CONTROL IN ECLIPSE

When optimizing the oil production, there might be some constrains that need to be accounted for. In this thesis, the constraint is the capacity of the surface facilities. To meet these restrictions, the production needs to be choked. Eclipse provides the opportunity to apply limitations to specified parts of the production network.

The pipeline network is divided into three different levels; the individual well level, the group level and the field level. Figure 17 shows a two well operational system, divided into three levels.

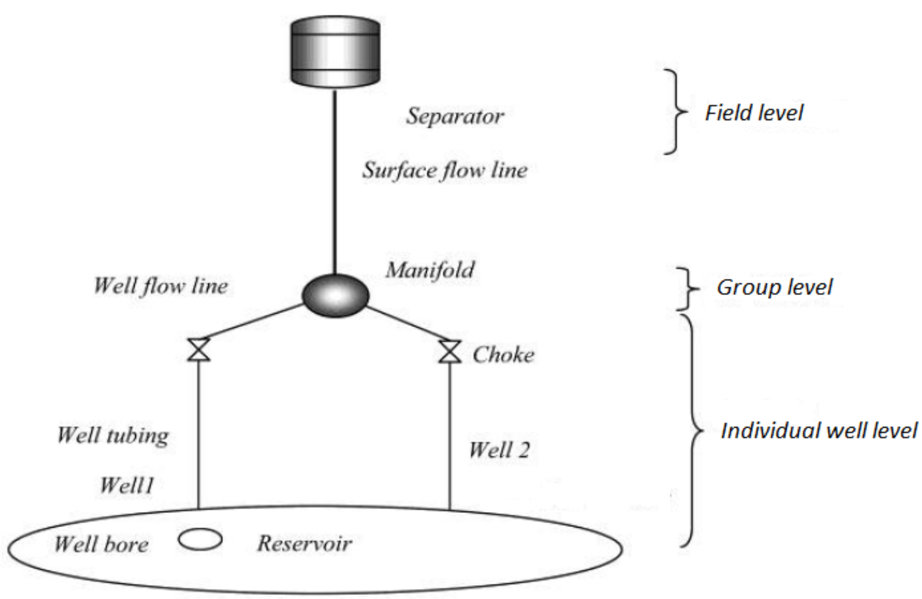


Figure 17- Two well operation system (Kosmidis, V., Perkins, J., and Pistikopoulos, E. 2004)

- The individual well level. Each well can be controlled by rates targets or tubing head/ bottom hole pressures.
- The group level. Groups with one or several wells can be given production targets or upper limits to reach overall targets.
- The field level. The surface facility capacities constrain the overall production rates.

Individual well level

In Eclipse, there are several ways to control the individual well rate. The well can operate at a target value of any of the following quantities:

- The oil rate
- The gas rate
- The water rate
- The liquid rate
- The bottom hole flowing pressure
- The tubing head pressure
- The linearly combined rate (a user-specified linear combination of oil, water and gas)
- The reservoir fluid volume (voidage) rate

In addition to the control quantities mentioned above, it is also possible to apply a maximum drawdown for a production well. This limit is converted into a maximum gas or liquid rate for each time step.

Group level

One or several wells can be gathered in one group, often based on which wells are using the same flow line. It is possible to give a group a production rate target or upper limit. This way, it is possible to constrain the production of a specified phase, to meet overall targets. This overall target could be the capacity of the surface facilities.
When using the Extended Network option, described in Chapter II, groups at any level in the hierarchy can be assigned a target value. This value can be specified for one of the following quantities:

- The oil rate
- The gas rate
- The water rate
- The liquid rate

- The bottom hole flowing pressure
- The tubing head pressure
- The linearly combined rate (a user-specified linear combination of oil, water and gas)
- The reservoir fluid volume (voidage) rate

This thesis will look further into what happens when a group's rate is constrained.

3.3.1 ALTERNATIVES WHEN EXCEEDING AN UPPER TARGET GROUP LIMITATION

In Eclipse, there are several different choices of actions when exceeding a maximum limit assigned to a group.

One alternative is to do nothing. So, if a group exceeds the limitation given to it, the wells just keeps producing the same way as before.

Another alternative is to cut back the "worst offending" connection in the "worst offending" well. The "worst-offending" well or connection is the one that has the highest production ratio of the violating phase.

It is also possible to close the worst offending well. By using this option, the well that is producing the highest phase of the violation phase will be closed successively, until the rate limit is honored.

The forth method is to control the group rate to equal the violated upper limit. In effect, the wells are choked at the well head.

Since the production on the Norne FPSO is capacity constraint, the option of "doing nothing" will not be used. The option of cut back the worst offending connection in the worst offending well is easily done in Eclipse, but in order to do so in reality it must be possible to measure the flow in different zones in a well. On Norne, this is not possible, so this option will not be used either. This leaves us with the third and fourth options, which will be discussed further in the next section.

3.3.2 CHOKING THE PRODUCTION – ECLIPSE METHODS

Eclipse has three ways of choking the wells in a group, when an upper limitation is exceeded. These are:

i) The Fraction Method
ii) Use of Guide Rates
iii) Use of Priority Rules

3.3.2.1 The Fraction Method

One alternative is to choke the production using the Fraction Method. With this method all wells are cut back when the water limitation is applied to the group. Eclipse cuts back each well based on the following:

Before the wells are choked, the total production rate of the nominated phase is calculated. The nominated phase is the phase that is in violation with the limit.

Eclipse then calculates the fraction of how much each well is producing of the total production rate of the nominated phase, as in Equation 1.

$$\text{Fraction of total production} = \frac{\text{Well production, nom. phase}}{\text{Group production, nom. phase}} \tag{1}$$

When the limitation is applied to the group, each well's fraction of the total production is used to determine how much each well is allowed to produce of the limited (nominated) phase, see Equation 2.

$$\text{Well production, nom. phase} = \text{Fraction of total production} \bullet \text{Upper limit, nom. phase} \tag{2}$$

3.3.2.2 Guide Rates

Another way of deciding how much each well is allowed to produce when a group is given an upper limitation is to use Guide Rates. With Guide Rates, the production rate of the nominated phase of each well is made in proportion to the Guide Rate of the well, calculated from Equation 3:

$$GR_{wat} = \frac{(POT_o)^A}{B + C(R_1)^D + E(R_2)^F} \tag{3}$$

Where,

POT = Oil Potential

R1 = Oil -Water Ratio, from potentials

R2 = Gas - Oil Ratio, from potentials

A, B, C, D, E and F are used defined powers and coeffisients.

The oil potential of a well is defined as the oil production rate the well would achieve in the absence of any rate constraints. The same yields for the gas and water potentials. The oil-water ratio and the gas-oil ratio used in the formula are calculated from the oil, gas and water potentials.

When the constraint is applied to the group, the Guide Rate for each well is calculated from Equation 3. The total Guide Rate for a group is then found, as the sum of the wells Guide Rates.

Deciding how much each well is allowed to produce of the nominated phase is done slightly different from the Fraction method. Here, the fraction is based on the Guide Rates for the nominated phase, instead of the actual water production, see Equation 4.

$$\text{Fraction of total production} = \frac{\text{Well Guide Rate, nom. phase}}{\text{Total Guide Rate, nom. phase}} \tag{4}$$

In turn, the wells production rate of the nominated phase is calculated from Equation 5.

$$\text{Well production, nom. phase} = \text{Fraction of total guide rate} \bullet \text{Total group. prod, nom. phase} \tag{5}$$

By changing the powers and coefficients A, B, C, D, E and F in Equation 3, the user has the opportunity to influence which well parameters that is significant when the Guide Rate is calculated.

Three cases are provided, to see how the Guide Rate calculated from Equation 3 is responding to different coefficients. Since the Guide Rates will be applied to wells that are mainly liquid producers, E and F will be set to 0.

Case 1: (A = 2, B = 1, C = 1, D = 1) – Wells with high oil potentials are allowed to produce a high shear of the total oil production for the group, even though they might have a high water cut.

The formula for the Guide Rate is given by:

$$GR_{wat} = \frac{(POT_o)^2}{1+(R_1)} \tag{6}$$

Case 2: (A = 1, B = 1, C = 2, D = 2) – In this case, the wells with high water cut is cut back, allowing the other wells in the group to produce a higher shear of the total production.

The formula for the Guide Rate is given by:

$$GR_{wat} = \frac{(POT_o)}{1+2(R_1)^2} \tag{7}$$

Case 3: (A= 1 , B = 1, C = 2, D = 3) – Here, the wells with high water cut is cut back even more than in Case 2, allowing the wells to produce more.

The formula for the Guide Rate is given by:

$$GR_{wat} = \frac{(POT_o)}{1+2(R_1)^3} \tag{8}$$

The different cases are applied to the Norne simulation model in Chapter V.

3.3.2.3 Prioritization

Prioritization is an alternative to Guide Rate control. This option gives the user an opportunity to turn wells on in decreasing order of priority, where the well with the highest priority goes first. The wells starts flowing in the correct order, until the group limit is reached. Each well operates at their individual targets or limits (see subchapter 3.3).

When a group exceeds a production limit, the well with the lowest priority at the time is cut back.

The wells priority number is calculated from each wells potential production rates see Equation 9.

$$\text{Priority} = \frac{A + BQ_o + CQ_w + DQ_g}{E + FQ_o + GQ_w + HQ_g} \tag{9}$$

Where,

Q_o, Q_w and Q_g are the well's potential oil, water and gas production rates

A-H are user defined coefficients, none negative.

By using this equation, it is possible to assign the wells with a high oil potential a high priority number or favor the wells with low water cut.

Two cases are provided to see how the cumulative oil production of a group is affected by different user defined coefficients in Equation 9.

The first case prioritizes the wells with a high oil potential, setting the coefficients B and E equal to 1, and assigning the other coefficients to zero. The priority equation is then given by:

$$\text{Priority} = Q_o \tag{10}$$

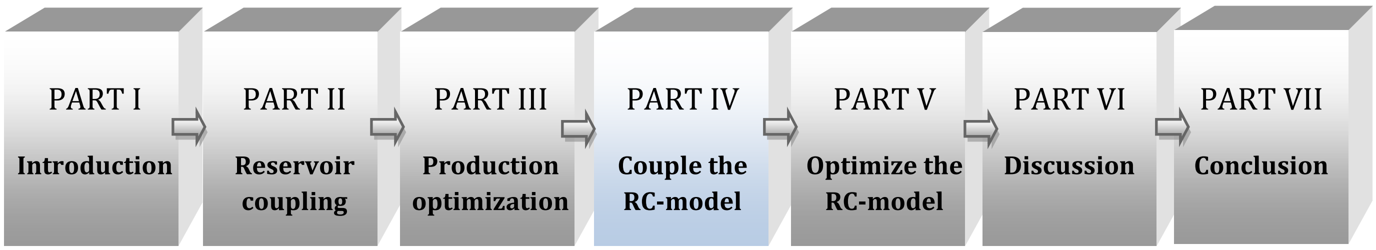
As shown in Equation 10, the wells with the highest oil potential are prioritized even though they might produce high volumes of water.

The second case prioritizes wells with low water cut, assigning the coefficients B, C and G a value of 1 and setting the others to zero. The priority equation is given by:

$$\text{Priority} = \frac{Q_o + Q_w}{Q_w} \tag{11}$$

If the oil potential is high compared to the water potential for a well, Equation 11 will assign the well a high priority number. On the other hand, if the well has a high water-production potential, the well is given a low priority number.

PART IV
COUPLING THE NORNE FPSO RESERVOIR MODELS



In Part IV, a presentation of the coupled model, made to optimize the Norne FPSO production, is given. This model includes the main field and all the satellites, and uses the elements described in Chapter II.

Further, an overview of which reservoirs that is located in the different slaves can be found.

A comparison of the production from the master and the Stand-alone model will also be shown.

Finally, the combined production profiles from the coupled model are presented.

4.1 THE COUPLED MODEL

As mentioned earlier, eight reservoirs are going to produce to the Norne FPSO. Each reservoir has its own stand-alone models simulation model.

To get a good overview of the total production rates, and be able to calculate the tubing head pressure (THP) for the reservoirs that are sharing the same flow line, all of these reservoirs are coupled together. This is done using the RC facility in Eclipse, described in Chapter II.

When coupled together, the stand-alone models are defined as slaves. One exception is Marulk, where the profiles are entered manually in the master data file.

An overview of how many reservoirs each slave represent, is shown in Table 4 below.

Table 4- Overview of the slaves and number of production wells

Name of the Slave	Name of the reservoirs	Number of prod. wells used in the model
Norne Slave	Norne reservoir (oil)	13
Urd Slave	Svale reservoir (oil)	3
	Stær reservoir (oil)	2
Alve Slave	Not reservoir (gas)	1
	Tilje reservoir (oil)	1
Skuld Slave	Fossekall reservoir (oil)	3
	Dompap reservoir (oil)	3

As shown, there are four slaves, containing seven reservoirs in total. The slaves represent the Norne main field and each of the satellites that are producing to the ship.
An overview of how the slave and master reservoirs are coupled together is shown in Figure 18. As mentioned earlier, the communication paths between the master and the slaves go through specified groups that are defined both in the slaves and in the master. These groups are shown in the figure by the dashed lines.

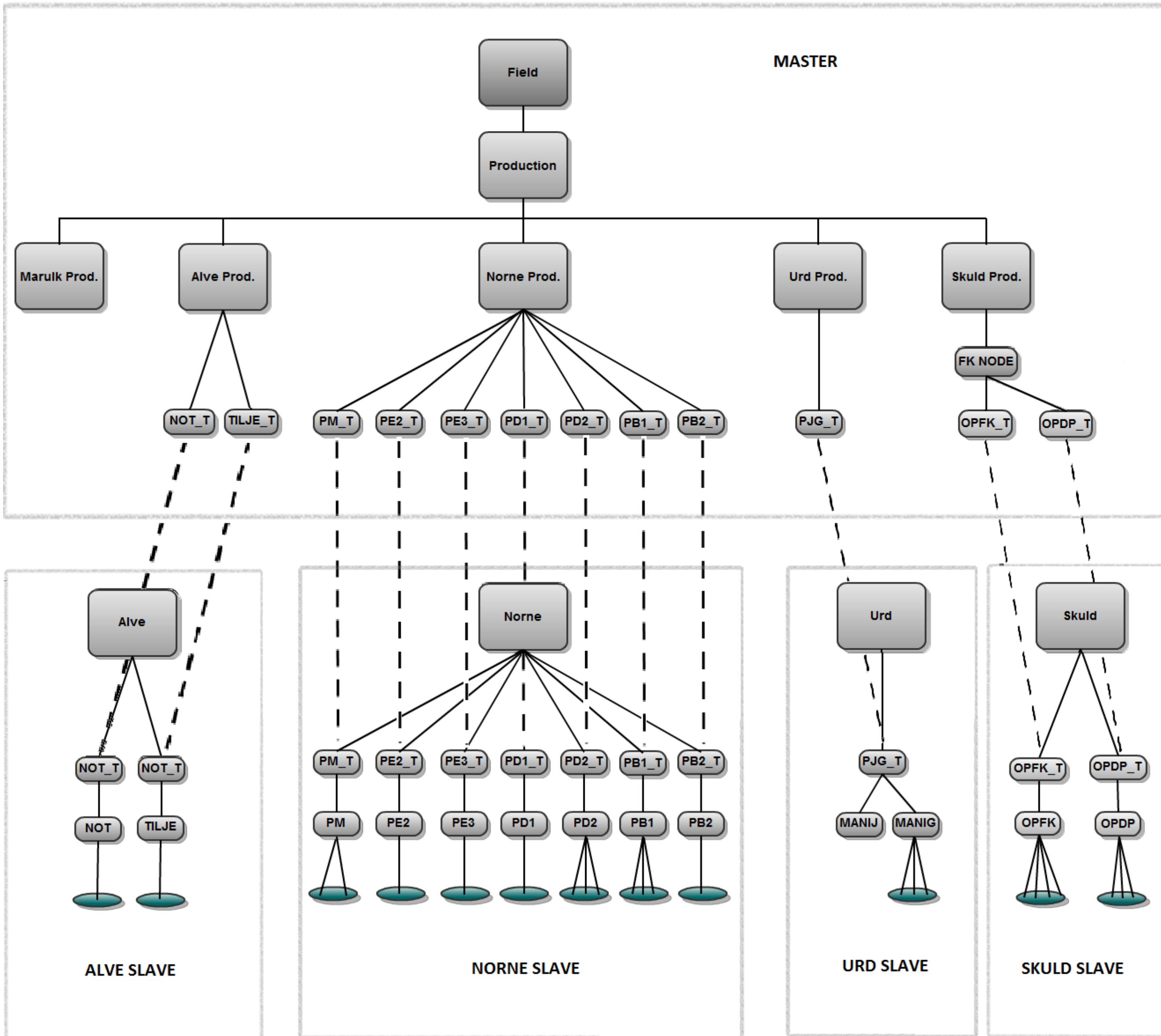


Figure 18- An overview of the coupled model, showing the master and slave reservoirs

In the figure above, the squares are representing different groups located in the master/slaves, while the blue ellipsis symbolizes a number of wells. As shown, there are groups in the master, for example Norne prod., that represents the total production from the Norne slave.

4.2 Comparison of the Master and Stand Alone Production Profiles

The master gathers the production from the different slaves, only contributing with the production from Marulk.

It is important that the groups in the master that represents the total production from each of the slaves are matching the “stand-alone” models.

To investigate if the production profiles from the groups in the master and the stand-alone production profiles are similar, they are plotted together in the same figure.

In Figure 19, the oil production rate from the Norne group in the master and the Norne Stand-alone model is compared. The production profiles look equal.

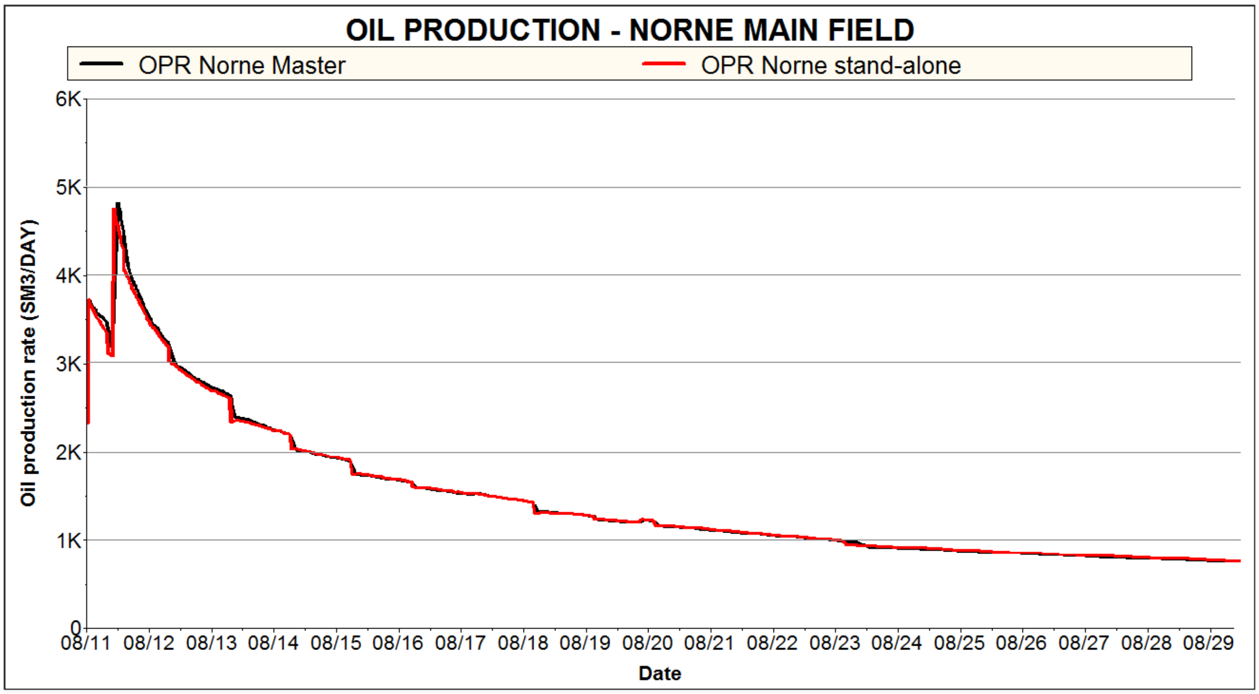


Figure 19 - Comparison of oil production rate between the Norne stand-alone model and the RC-model

By looking at the Urd production profile from the master, and the Urd Stand-alone production profile in Figure 20, some small differences are shown.

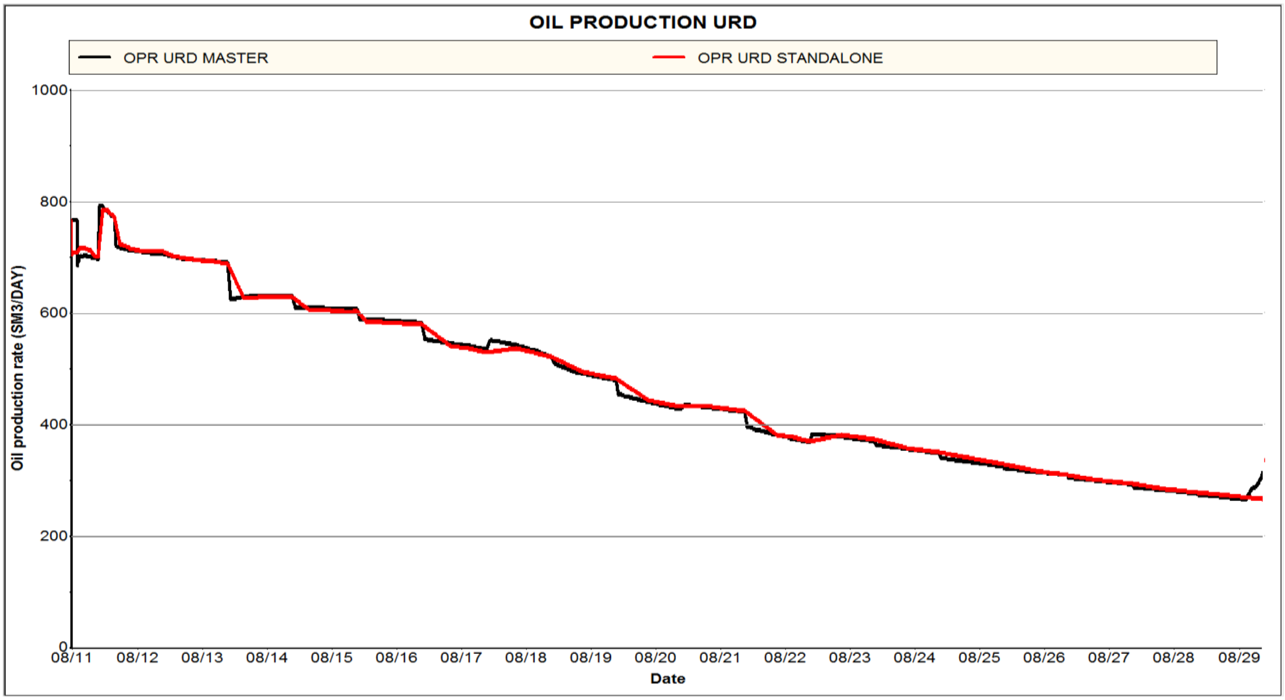


Figure 20 - Oil production rate for the Urd stand-alone model and the RC-model (TSMAXZ = 365)

By changing the maximum length of the time step after the next (keyword TSMAXZ) in the Urd Stand-alone data file from 365 days to one day, the differences disappear.

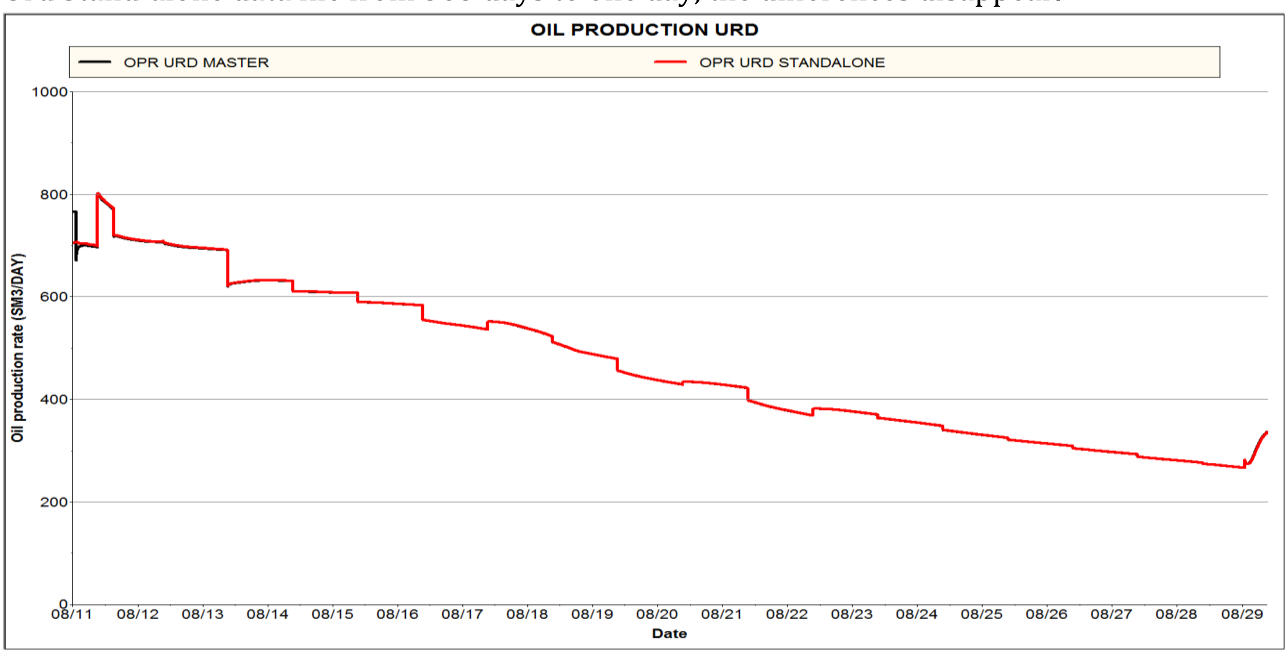


Figure 21- Oil production rate for the Urd stand-alone model and the RC-model (TSMAXZ = 1)

The comparison between oil production rates for the groups that represents the slaves in the master, and the oil production rates for the stand-alone models, is done for all of satellites, see Appendix A. They are all matching quite good.

4.3 THE TOTAL PRODUCTION PROFILES FOR THE COUPLED MODEL

The RC-model makes it easy to plot the total production rates for the reservoirs that are producing to the Norne FPSO. This will help the production engineers to decide if the production facility capacities hold, or if the production needs to be choked.

Figure 22 shows the total oil production rate, and the cumulative oil production. The oil production rate will peak in July 2013.

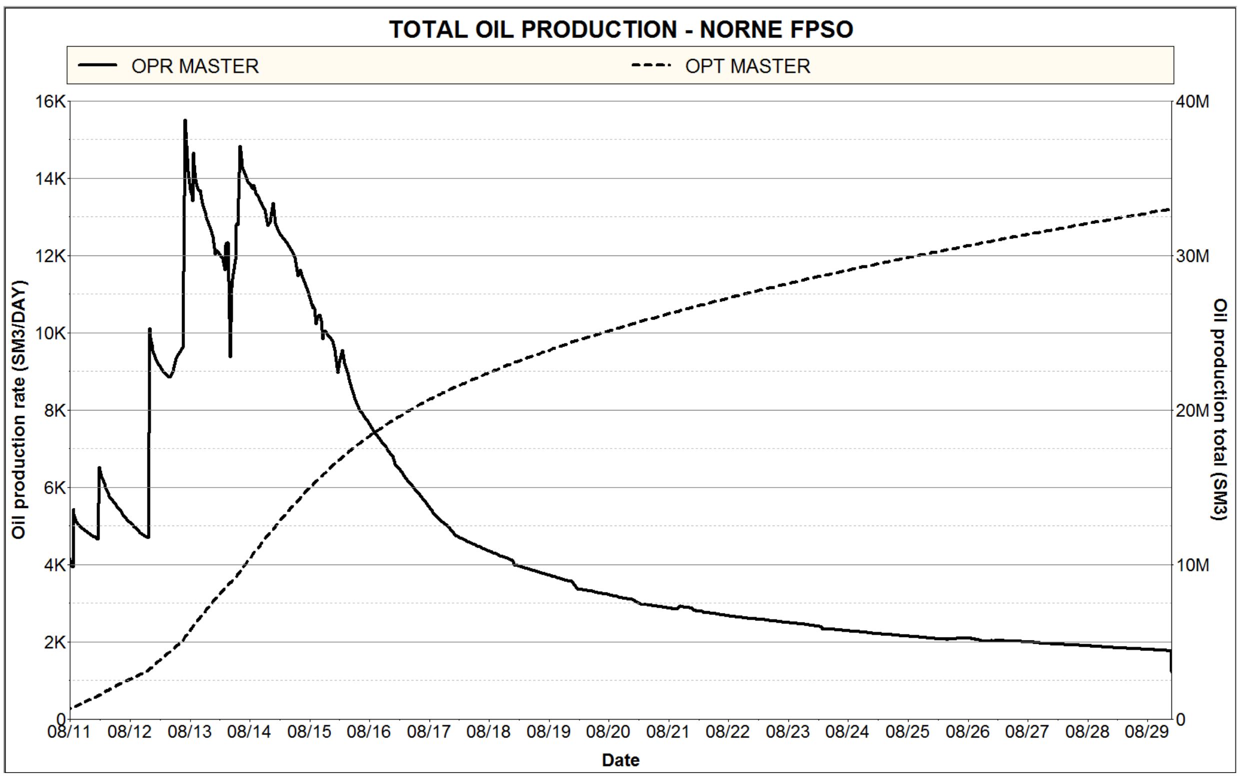


Figure 22- The total oil production rate and cumulative oil production for the Norne FPSO (RC-model)

Figure 23 shows the total water production for the Norne FPSO. The water processing capacity is 30000 Sm3/day, and this limit is exceeded in July 2016. To honor this limitation, the production needs to be choked.

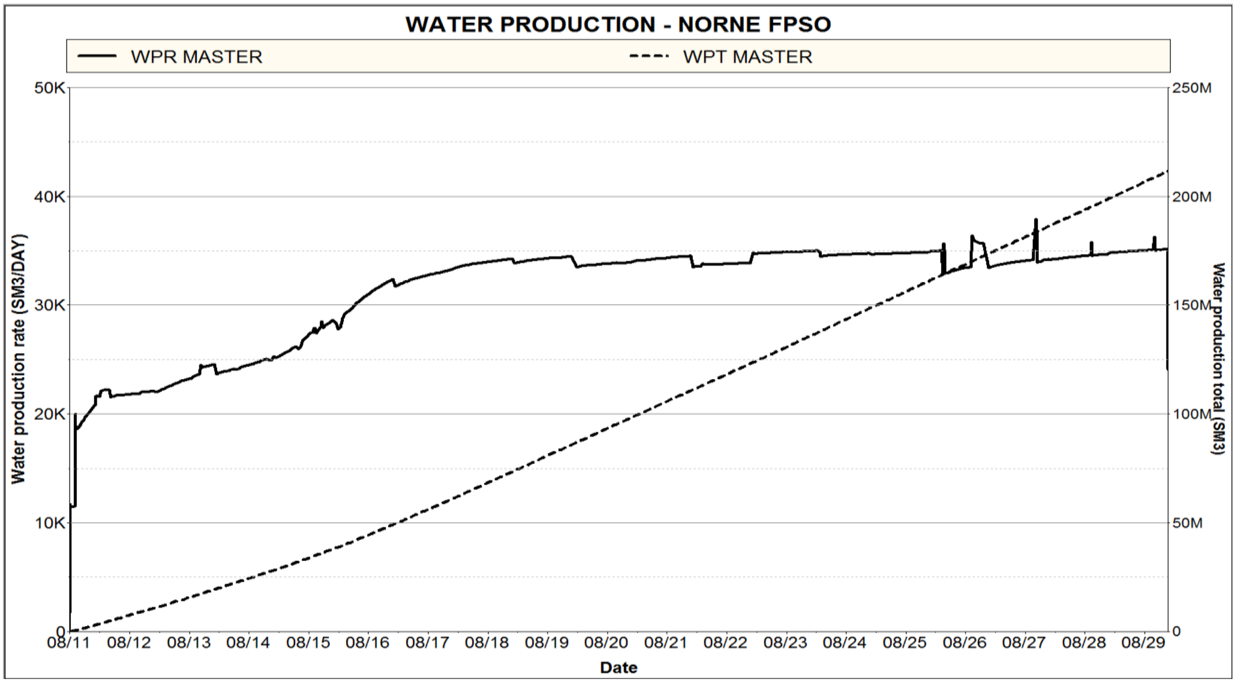


Figure 23 - The total water production and the cumulative water production for the Norne FPSO (RC-model)

The total production is showed in Figure 24. Marulk and Alve contribute with the most of the gas production.

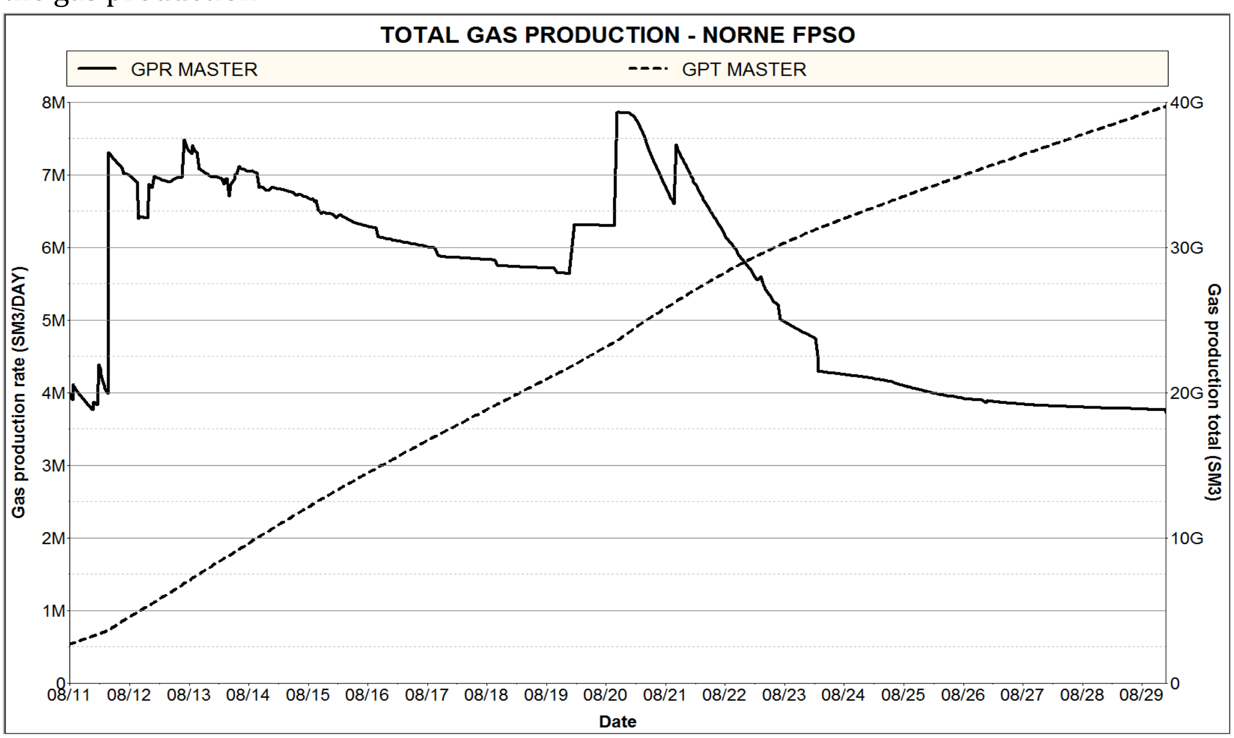
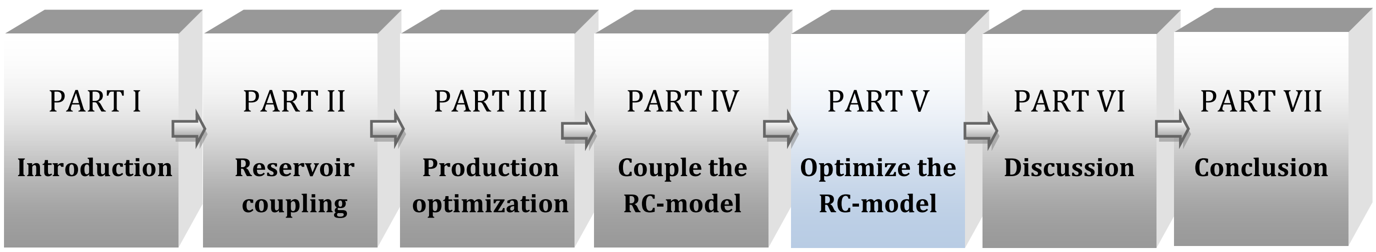


Figure 24-The total gas production rate for the reservoirs that are producing to the Norne FPSO (RC-model)

PART V
OPTIMIZING THE NORNE FPSO HYDROCARBON PRODUCTION



In Chapter V, the simulated hydrocarbon production on the Norne FPSO will be optimized.

First, the Gas Lift Optimization Facility in Eclipse will be applied to the Urd Stand-alone model, to minimize the gas lift on Svale.

Then, the different methods of choking the production, mentioned in Chapter III, will be applied to the Norne Stand-alone model, to constrain the water production. To understand how the different methods work in detail, examples of the calculations will be given. A comparison of the cumulative oil production gained from the different methods will also be shown.

Finally, the hydrocarbon production for the RC-model will be optimized. Combined production plots, for the optimized model, will be shown.

5.1 LIMITING GAS LIFT RATE ON SVALE

A sensitivity analysis for gas lift has been carried out, to determine which parameters influence the production. The Urd stand-alone simulation model has been used, but since the production from the wells on Stær are entered manually in the Eclipse Data file, the sensitivity analyses will only be carried out for the wells on Svale.

The simulation results are compared to the base case, where the gas lift is 250 000 Sm3/day pr. well.

Svale consists of three wells; and the names are shortened to G1, G2 and G4.

The following cases are studied:

- The gas lift for each well has been reduced to 140 000 Sm3/day.
- The gas lift injection rate for each well has been reduced to a minimum, just enough to let the wells produce, and thereby allow Alve to produce more.
- The liquid rate for the well G1 has been reduced to minimize the flow in the pipeline.
- The Gas lift and water cut effect on the wellbore pressure are investigated

Note! In the Urd stand-alone simulation model, there are uncertainties regarding the effect of the gas lift on Svale (see Chapter VI, Discussion).

5.1.1 REDUCTION IN GAS LIFT

By use of gas lift in a liquid producer, the density of the production stream will decrease, and the well is expected to produce higher rates. But since the fluid flow needs to be transported in a several kilometers long pipeline along the seabed, it is also important to understand how more injected gas will affect the pressure drop here. The pressure drop due to friction may negatively counteract the positive effect in the well.

The gas lift injection rate (GLIR) was reduced from 250 000 Sm3/day pr. well to 140 000 Sm3/day pr. well. Figure 25 shows the pressure at the manifold. The black line represents the base case, while the red line shows the case where the gas lift rate is reduced. As shown, a decrease in the gas lift leads to a decrease in the pressure at the manifold.

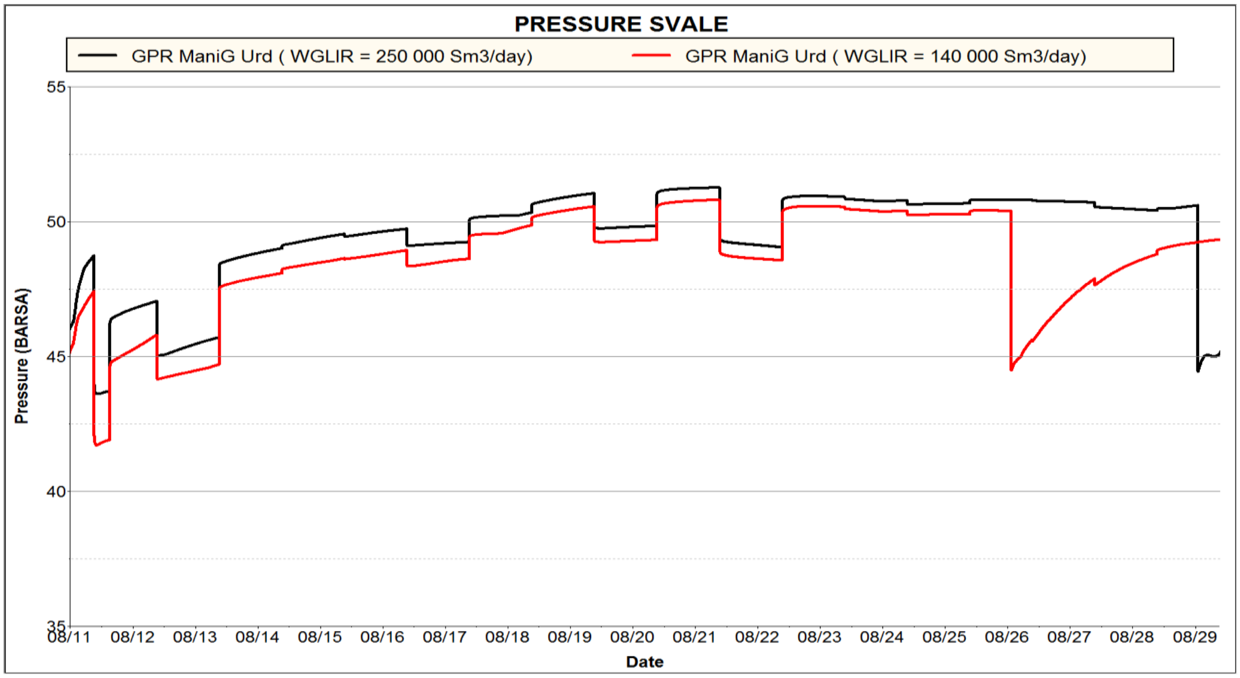


Figure 25 - Pressure at the manifold at Svale (Reduced gas lift)

The pressure at the manifold is determined by the inlet pressure at the ship, the fluid ratios and the friction in the pipeline.

To explain why the pressure at the manifold decreases when the gas lift is reduced, three cases were studied. The only parameter that was changed was the GLIR. The three cases are shown in Table 5.

Table 5- Three cases with change in gas lift

	Rate [Sm3/day]		
	Case 1	Case 2	Case 3
Liquid	5000	5000	5000
Oil	1000	1000	1000
Water	4000	4000	4000
Gas solution	60000	60000	60000
Gas lift	1000000	700000	500000
Total GOR	1060	760	560

The three cases were simulated in a program named Prosper, and the results are shown in Figure 26. This plot shows how the pressure is changing in the pipeline, from the ship to the manifold at the sea bottom.

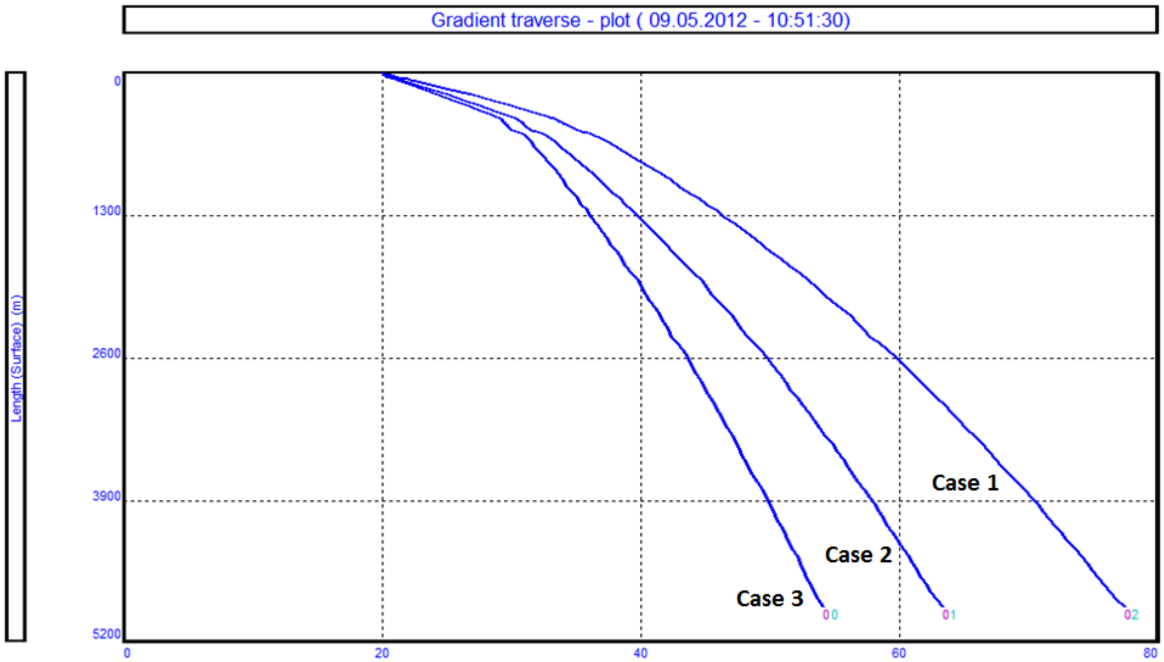


Figure 26 - Pressure drop in the pipeline from Urd to the ship, three different cases

The figure shows that a higher GLIR (Case 1) gives a higher pressure at the manifold, which is consistent with Figure 25. The additional pressure is caused by friction.

The oil production for Urd is shown in Figure 27. The case where the gas lift is reduced is illustrated by the red line, while the base case is illustrated by the black.

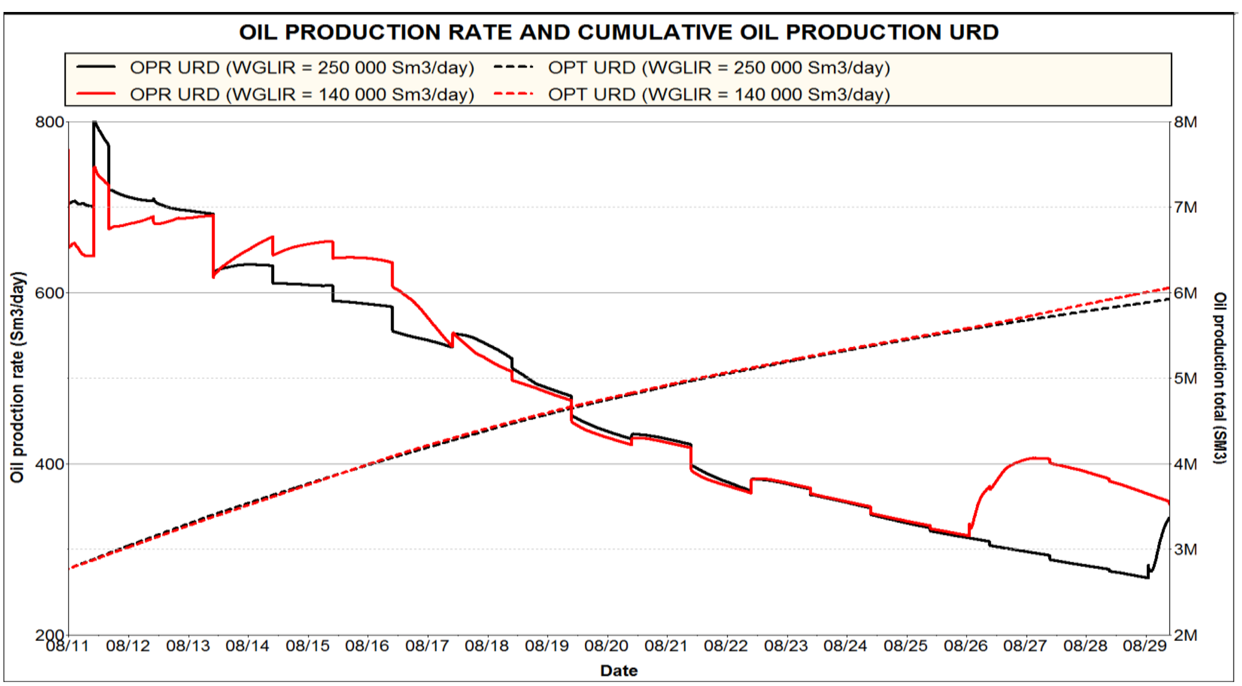


Figure 27 - Oil production on Urd (reduced Gas Lift Injection Rate compared to base case)

The production rate increases rapidly in August 2026. The explanation can be found in the Svale simulation model. Here, it is stated that if a well gets a water cut larger than 99%, the well is shut down. When the gas lift injection rate is reduced, the well G1 reach the water-cut limit earlier than in the base case, see Figure 28.

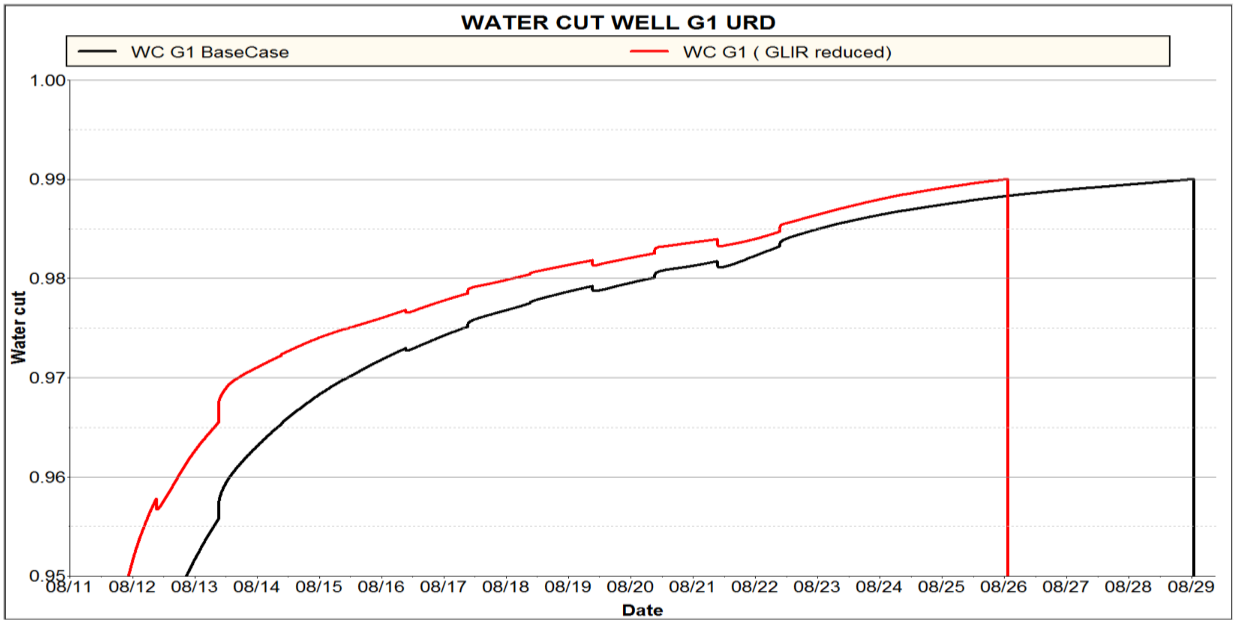


Figure 28- Water cut for well G1 (reduced Gas Lift Injection Rate compared to base case)

When G1 dies, there is a reduction in the pressure drop in the pipeline, the pressure in the reservoir increases, and the other two wells starts to produce more, see Figure 29.

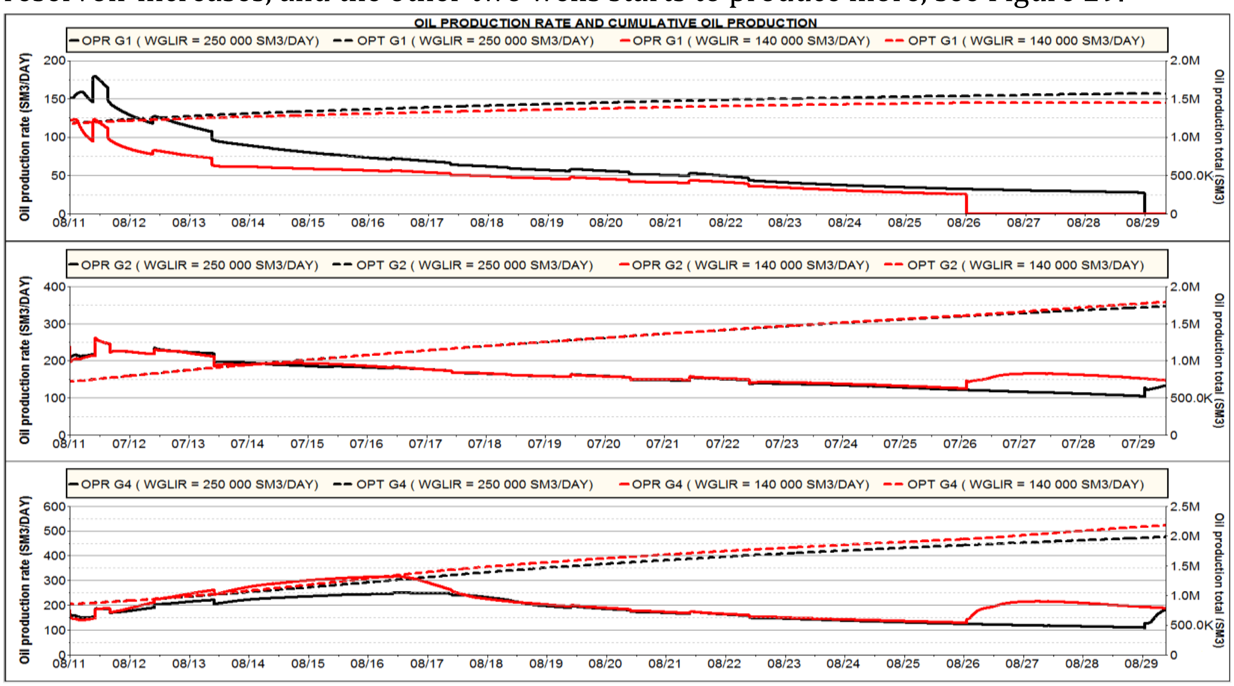


Figure 29- Oil production for the three wells on Svale (reduced Gas Lift Injection Rate compared to base case)

The positive effect of shutting G1 can be an effect of the Urd simulation model (See Chapter VI, Discussion).

5.1.2 Minimum gas lift injection rate

With the Gas Lift Optimization Option, it is possible to set the gas lift at minimum, to keep the wells producing, and thereby release space on the gas processing plant. The simulated minimum GLIR for each well is shown in Figure 30(red line).

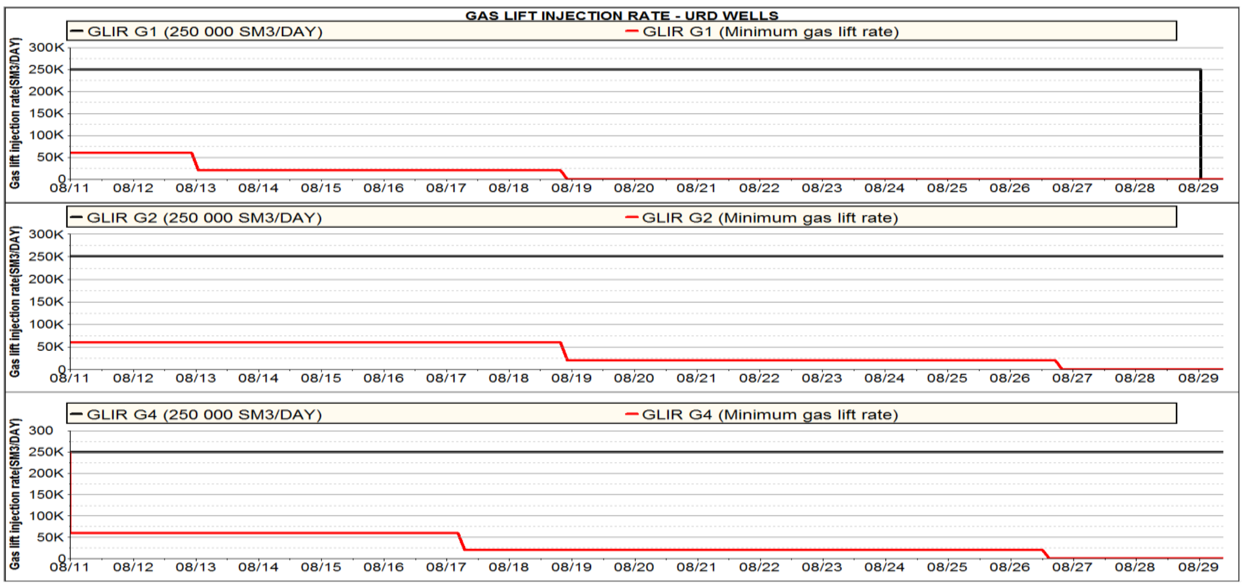


Figure 30- Minimum gas lift injection rate for the wells at Svale, compared to base case

The oil production decreases when the gas lift injection rate is set to a minimum, see Figure 31. Then the gas fraction in the production stream decreases, the density increases, and the production rate goes down.

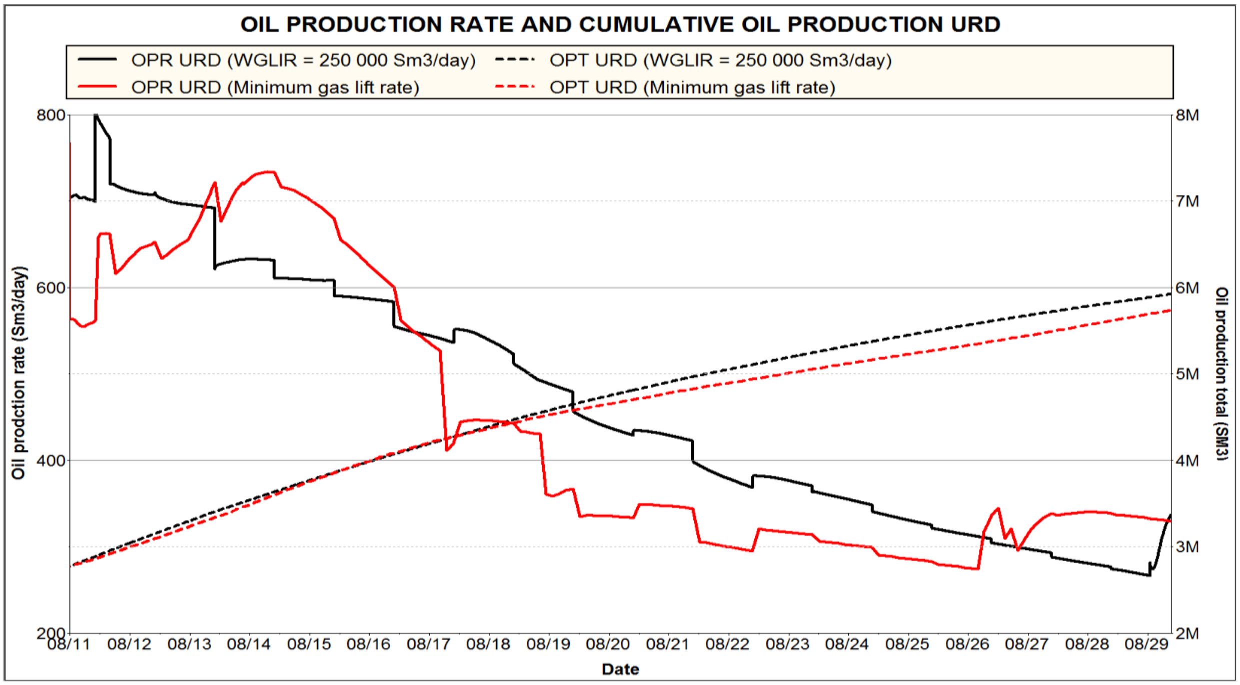


Figure 31 - Oil production on Urd (Minimum Gas Lift Injection Rate compared to base case)

5.1.3 CHANGES IN LIQUID PRODUCTION RATE FOR WELL G1

The flow in the pipeline is one of the parameters which influence the pressure drop, and hence it influences the oil production. To see how much influence the rate has, three cases were investigated, by varying the liquid production rate of well G1.

- Case 1 – LPR limit for well G1 is set to 2250 Sm3 / day
- Case 2 – LPR limit for well G1 is set to 2000 Sm3/ day
- Case 3 – LPR limit for well G1 is set to 1500 Sm3/ day

Figure 32 show the limitation applied to well G1 for the three different cases, compared to the base case.

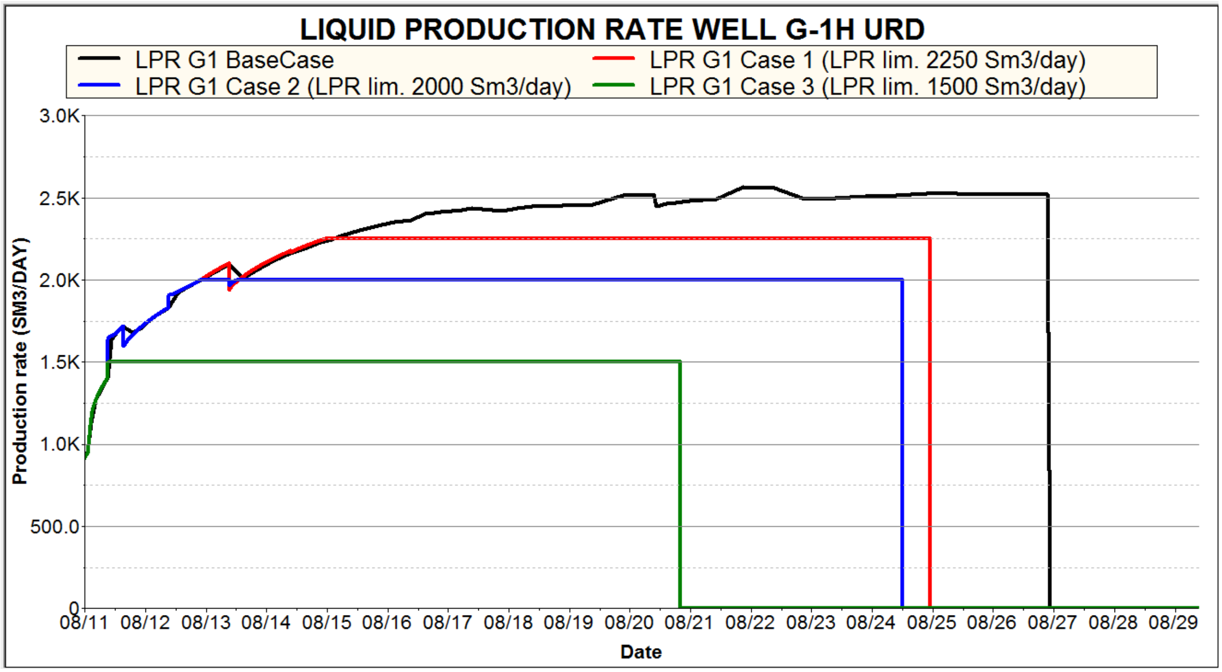


Figure 32 - Change in Liquid Production Rate for well G1 on Svale

The oil production rate for the different cases can be found in Figure 33.

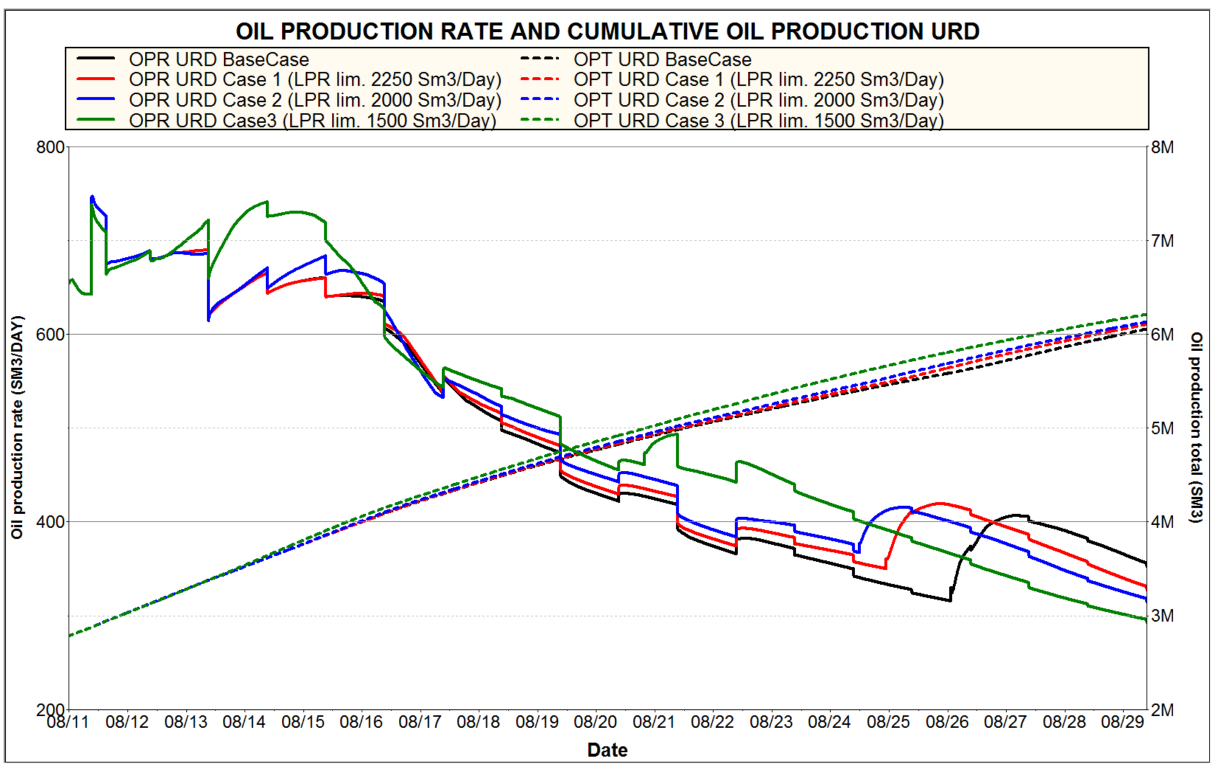


Figure 33- Oil Production Rate and Oil Production Total (Liquid Production Rate reduced on G1)

As shown, less liquid rate gives a higher cumulative oil production.

Note! The simulation result shown here has not been observed in reality, and could be an effect of the simulation model (see Chapter VI, Discussion).

An increase in the oil rate when choking/shutting G1 could be explained by a combination of the following:

1. The reservoir pressure increases when G1 dies
2. The pressure in the pipeline decreases, allowing other wells to produce more
3. The well G1 is producing from several different layers, with different saturations. Reducing the liquid rate could result in the well producing more from the good oil zones

5.1.4 GAS LIFT AND WATER CUT EFFECT ON THE WELLBORE PRESSURE

To understand how the fluid composition is influencing the pressure in a well, another study is done. Here, the vertical flow performance table for the well G4 is used as base. Two cases were studied, as shown in Table 6.

In the first case the water cut in the well is 50%, and 140 000 Sm3/day of gas is injected. The pressure at the top reservoir is 89 bar.

In the second case, the injection of gas is increased to 250 000 Sm3/day. This would normally make the density smaller, and the pressure at the top reservoir should decrease. But the water cut is also increased, to 60%. As shown, this gives a pressure at the top reservoir of 102 bars.

Table 6 - Fluid composition influence on pressure drop

Parameters	Case 1	Case 2
WC [%]	50	60
GLIR [1000Sm3/day]	140	250
THP [Bar]	40	40
Pressure top res. [Bar]	89	102

This means that the water cut influence the pressure in the well more than the gas lift.

5.2 Choking the production on Norne

In the simulation model, the water handling capacity of 30 000 Sm3/day is exceeded in July 2016, see Figure 34. The figure also shows how much water each field is contributing with, in proportion to the total water production.

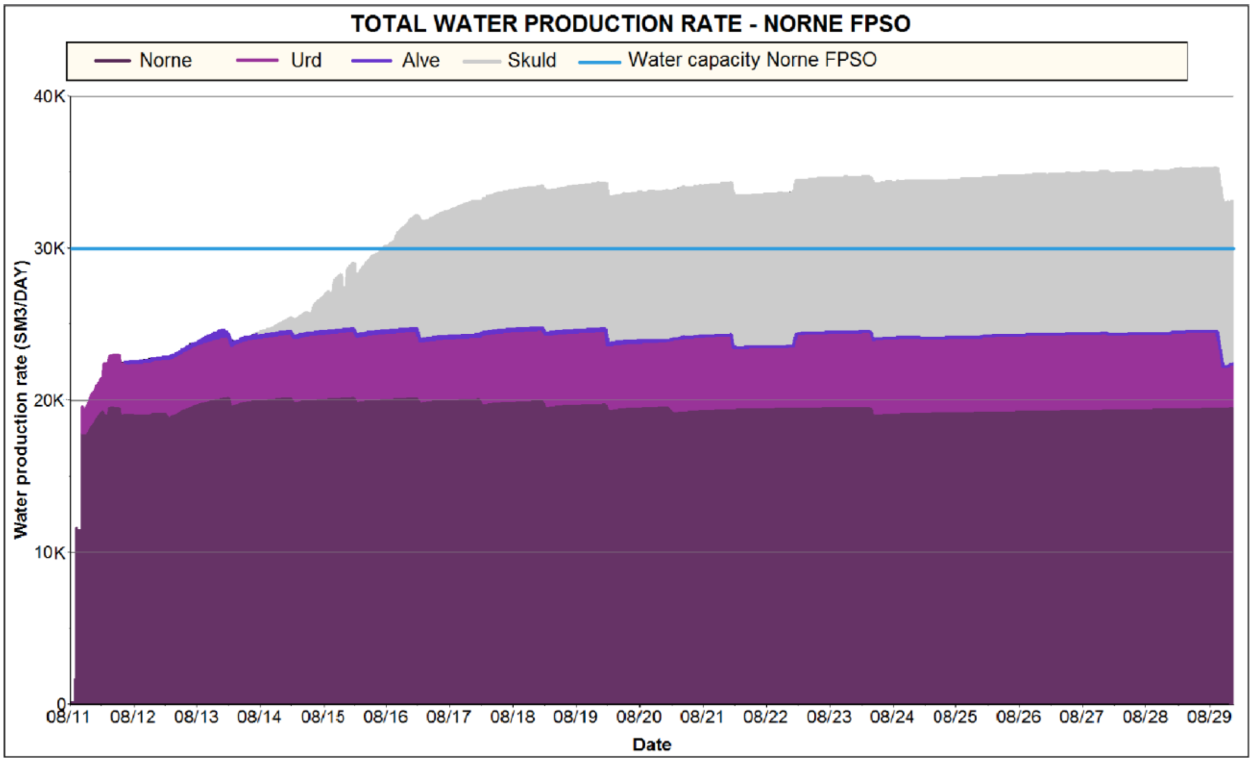


Figure 34- Norne and the satellite's share of the total water production

Among all the fields, Norne produces most water, and has the lowest oil rate. Therefore, the focus will be to constrain the water production here.

From July 2016, the water production in the Norne stand-alone model is constrained to 15 400 Sm3/day. This is just a chosen number, to see how the simulation model is responding to different methods of choking the production, described in Chapter III.

To understand how the methods work in detail, examples of the calculations will be given.

In the following figures, the black line illustrates a base case, where all the wells on Norne are producing at potential, while the red line illustrates a case where a water limitation constraint is assigned to the group or the field.

The water production rate and the cumulative water production for Norne, when the water limitation is applied to the field, are shown in Figure 35.

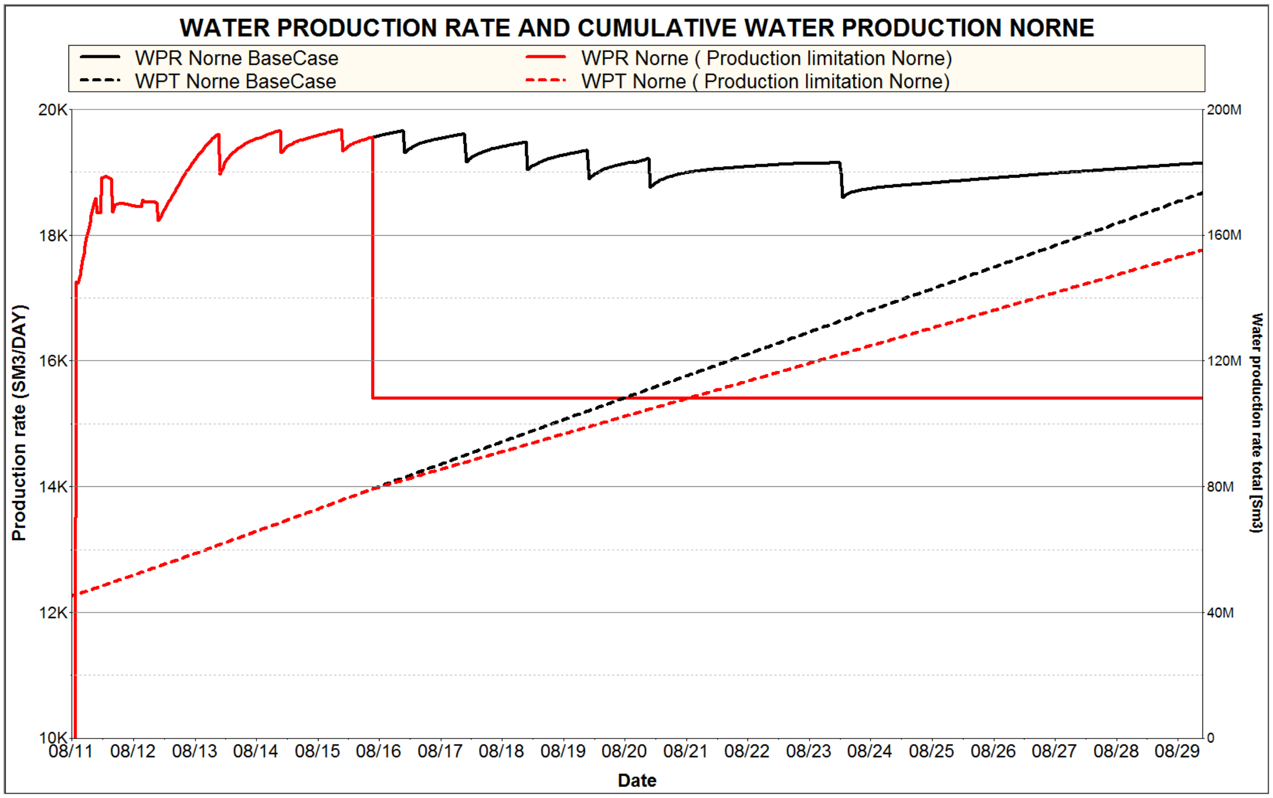


Figure 35- Water production on the Norne main field (Water limitation and base case)

Norne consists of 13 oil producers. In the simulation model, all the wells are collected in groups, based on which flow line they are producing to.

An overview, of which wells are gathered together, is shown in Table 7.

Table 7 - Overview of which groups that are gathered together

Group name	Wells		
PB1	*6608/10-K-1 H*	*6608/10-K-4 H*	*6608/10-B-4 DH*
PB2	*6608/10-B-1 BH*	*6608/10-P 20*	
PD1	*6608/10-D-1 DH*		
PD2	*6608/10-K-2 AH*	*6608/10-K-3 H*	*6608/10-D-4 AH*
PE2	*6608/10-E-4 AH*		
PE3	*6608/10-E-3 CH*		
PM	*6608/10-M-3 H*	*6608/10-M-4 AH*	

Chapter III has shown that production limitations can be applied to individual wells, as well as to whole groups. There are also different ways of constraining the production, and it is not easy to predict which method gives the highest cumulative oil production.

Therefore, a trial and error method is used, to find the method that gives the highest recovery of oil.

Then, the cumulative oil production for each method has been observed and compared to each other, and to the base case.

The different methods are the following:

- Manual optimization – Choke the well with highest water production. On the Norne main field, this well is named NO 6608/10-B-1 BH, shortened to B1.
- Manual optimization – The groups PB1 and PD2 is choked, using the fraction method
- Eclipse optimization – The groups PB1 and PD2 is choked, using Guide Rate
- Eclipse optimization – The wells B1 and E3 are choked, using Guide Rate.
- Eclipse optimization – The wells B1 and E3 are choked, using Priority Rules.

5.2.1 CHOKE THE WELL WITH HIGHEST WATER PRODUCTION (WELL B1)

The first alternative considered was to choke the well with the highest water production, well B1. While most of the wells are located in the Ile formation, B1 are placed on a high area, in the Tofte formation, deeper down in the reservoir. Even though the well produces a large amount of water, it is one of the best oil producers on the field.

In the simulated base case the well has a water production rate of approximately 7000 Sm3/day originally (black line). By restricting the water production on Norne to 15 400 Sm3/day, and allowing the other wells produce at potential, the water production rate on B1 is choked to 2000 Sm3/day (red line), see Figure 36.

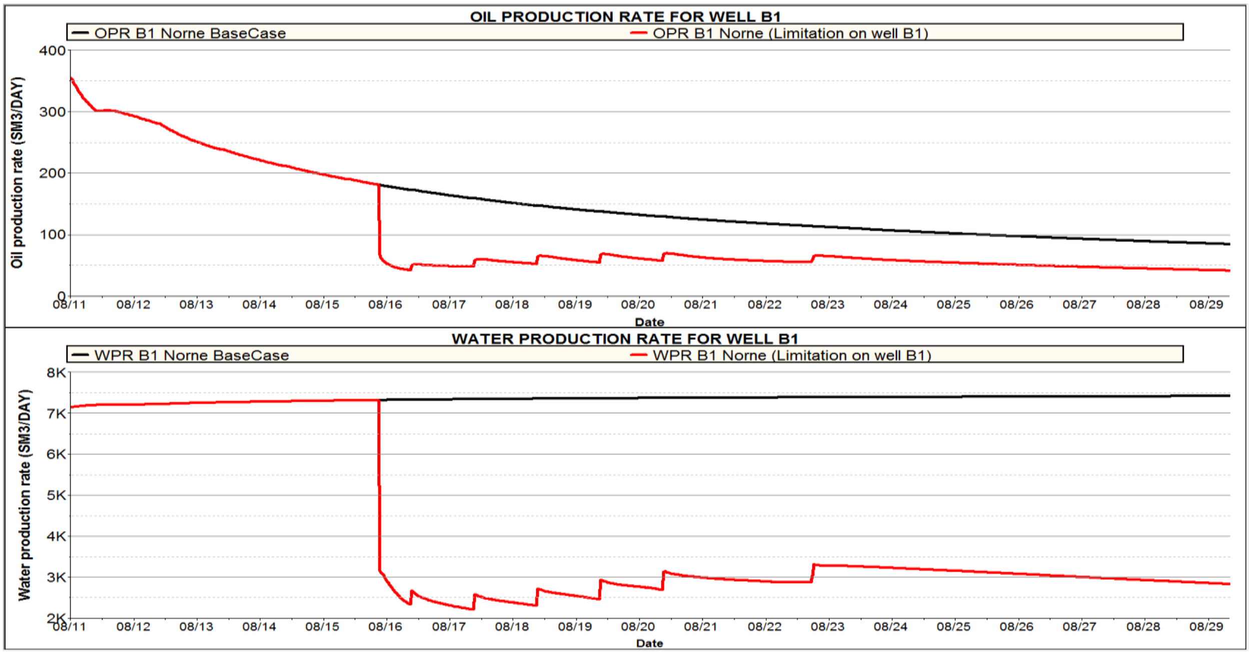


Figure 36- Oil and water production rate for the well B1 on Norne main field (B1 choked)

When B1 is choked, the liquid production rates of the other groups increase. This is seen in Figure 37 and Figure 38, where the oil and water production is shown for the Ile-group PB1.

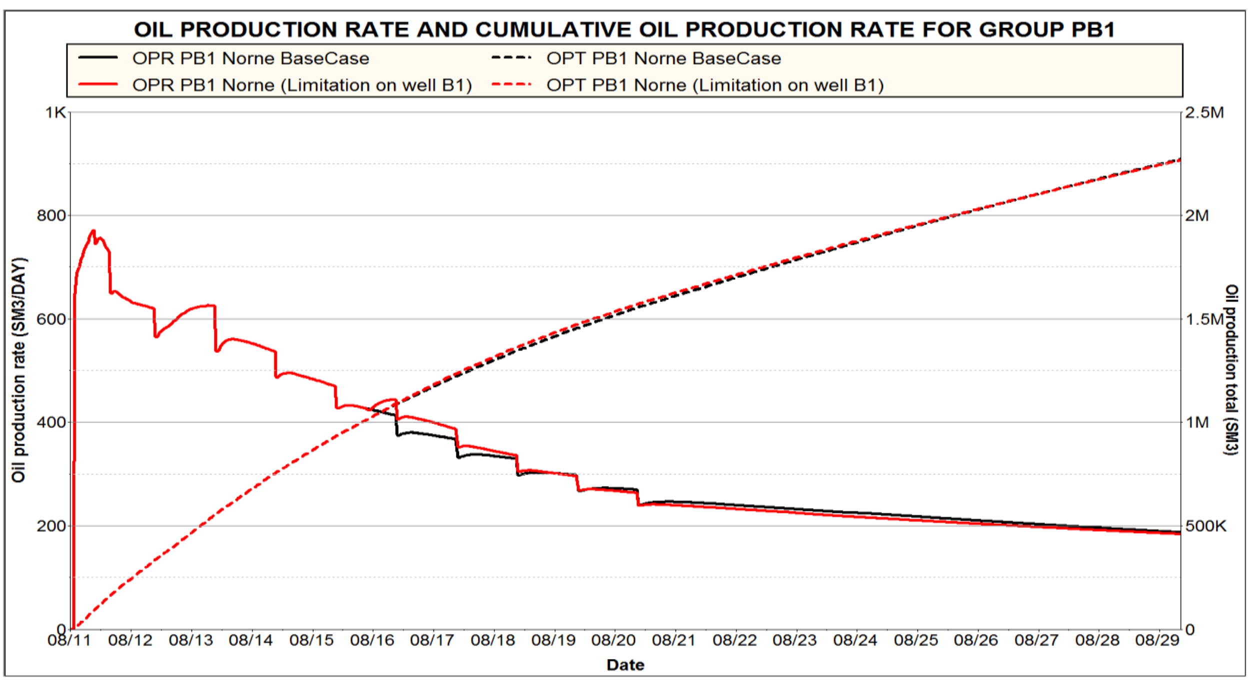


Figure 37 - Oil rate an cumulative oil production for group PB1 (B1 choked)

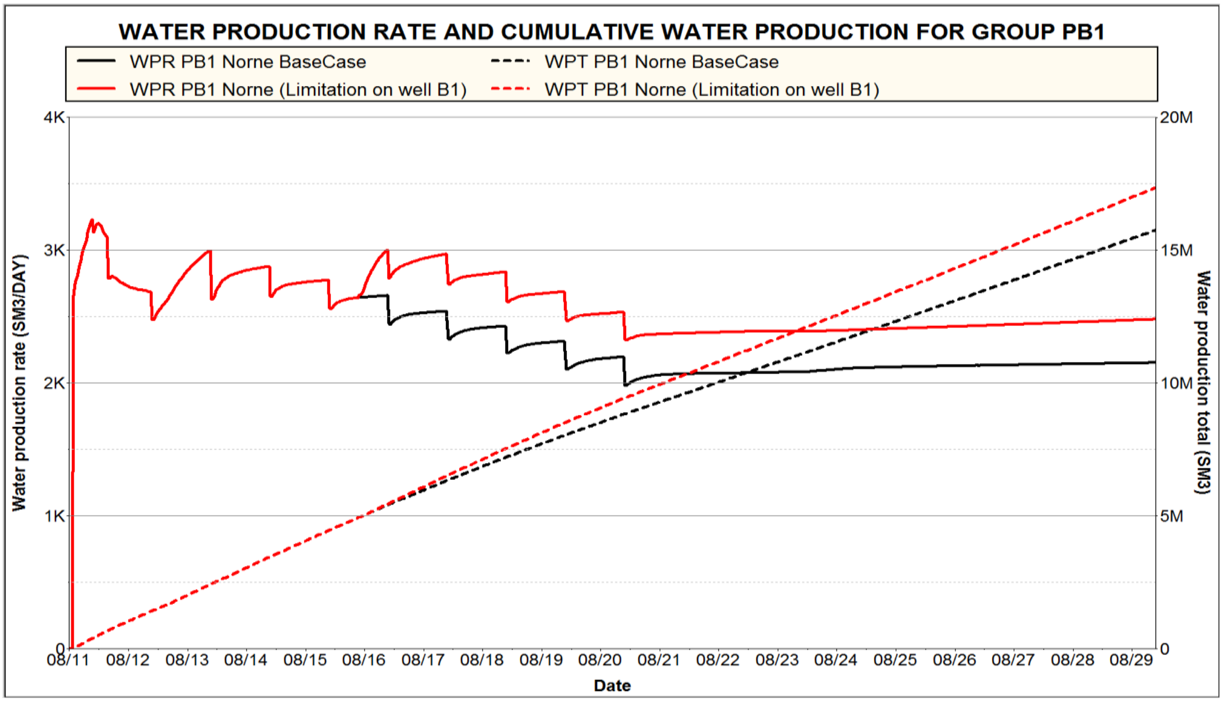


Figure 38- Water rate and cumulative water production for group PB1 (B1 choked)

As shown, the oil production is the same as in the base case, while the water production has increased. This trend, where the Ile wells produce a higher liquid rate, but unchanged oil rate, can also be observed for other groups, see Appendix B.

It can be explained by the following:

By reducing the liquid outtake from Tofte, the pressure in Tofte increases, resulting in increased influx from Tofte to the Ile producers, see Figure 39. At the same time, the Ile producers are producing the same volume as before, from the Ile formation.

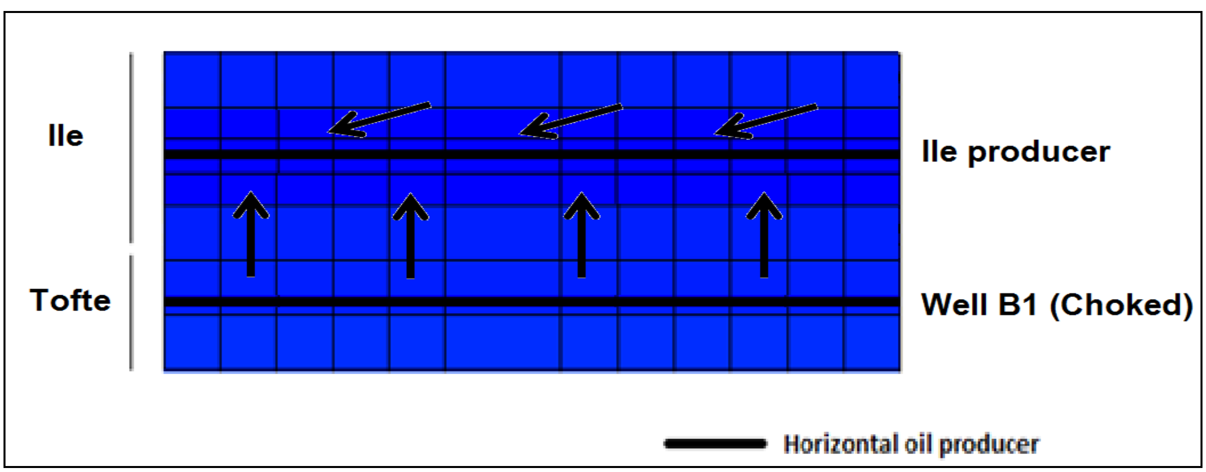


Figure 39 - Increased influx from the Tofte formation to the Ile producers (B1 choked)

Since the Tofte formation is mainly water filled, this leads to an increase in the water production of the wells, while the oil production stays the same.

The total oil production on the Norne main field, compared to the base case, is shown in Figure 40. The difference in the cumulative oil production for the two cases is approximately 345 000 Sm3 of oil.

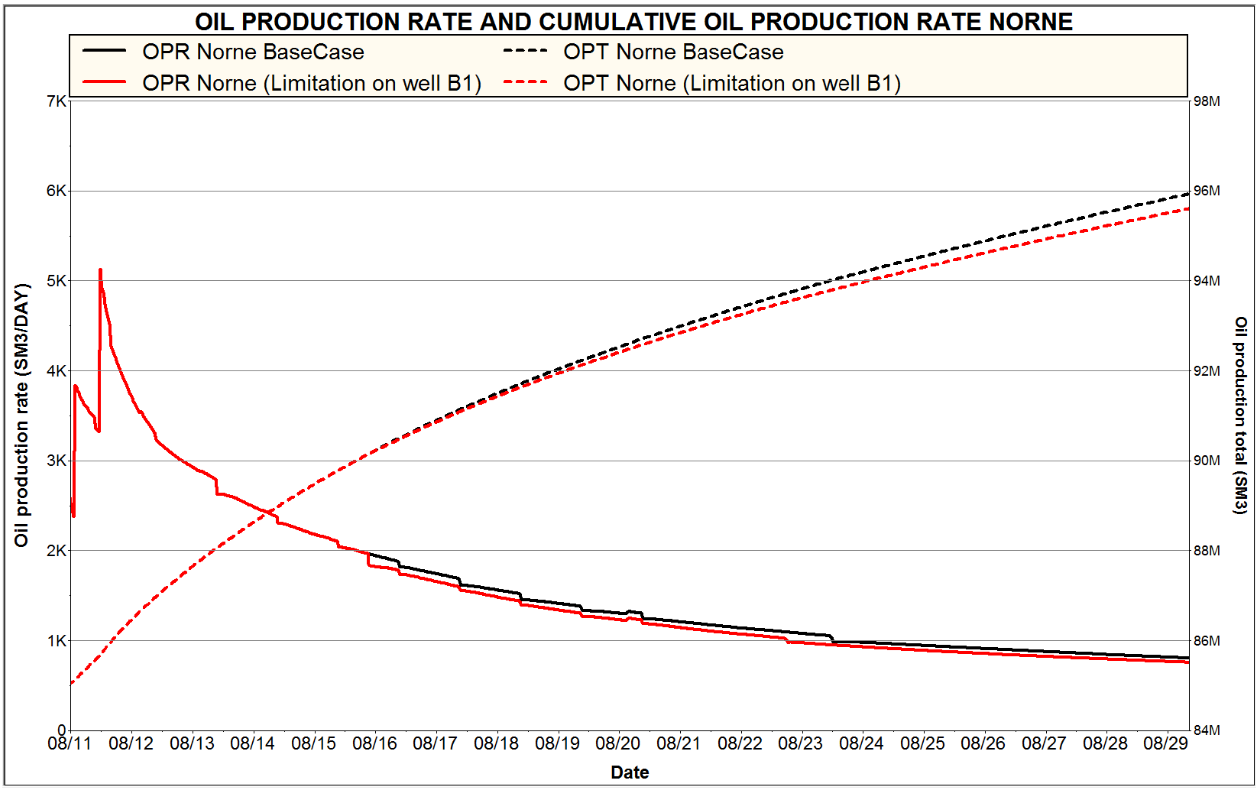


Figure 40- Oil production rate and cumulative oil production for the Norne main field (B1 choked)

5.2.2 Choking groups PB1 and PD2 using the Fraction method

The production on Norne was also choked using the Fraction method. The two well groups PB1 and PD2 were given water limitations of 2000 Sm3/day. The wells in these groups are located in the Ile formation, and have relatively low water cut.

To honor the limitation applied to Norne, the wells 6608/10-B-1 BH and 6608/10-E-3 CH, shortened to B1 and E3, needed to be choked, too. They were sat under group control from the Norne field, and choked using the Fraction method. All the other groups were producing at potential. This is illustrated in Figure 41.

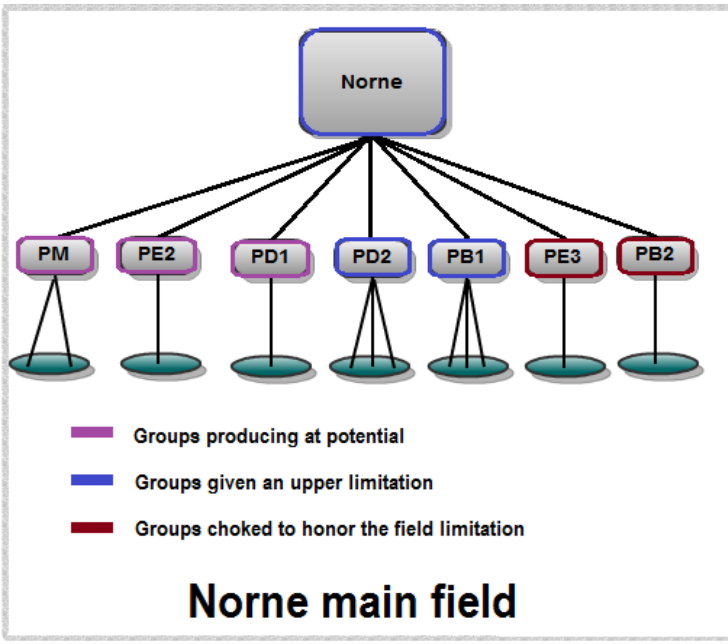


Figure 41 - Overview of which groups are given a limitation

To understand how the Fraction Method works, it will be shown in detail for group PB1. This group consists of the wells 6608/10-K-1 H, 6608/10-K-4 H and 6608/10-B-4 DH, shortened to K1, K4 and B4.

The water production rate and the total water production for group PB1, that is given a rate constraint of 2000 Sm3/day from the 1st of July 2016, is shown in Figure 42.

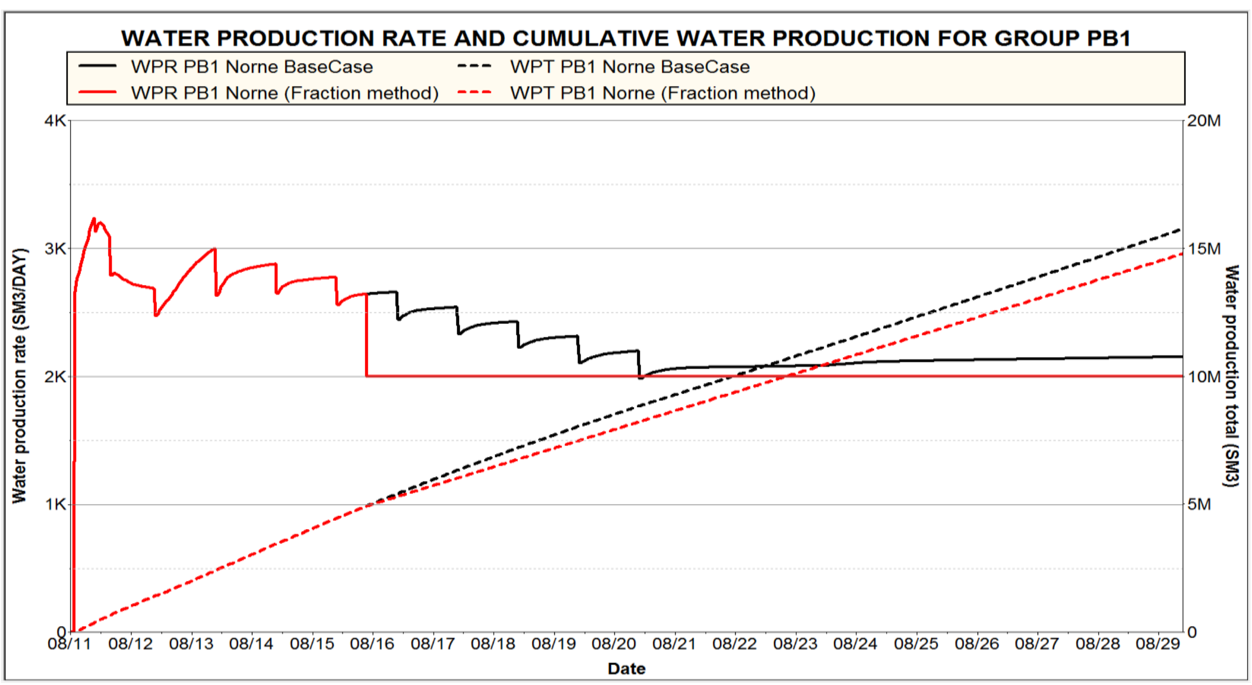


Figure 42 - Water production rate and cumulative water production for group PB1 (Fraction method)

For simplicity, the equations used in the Fraction method are stated below:

$$\text{Fraction of total production} = \frac{\text{Well production, nom. phase}}{\text{Group production, nom. phase}} \quad (12)$$

$$\text{Well production, nom. phase} = \text{Fraction of total production} \bullet \text{Upper limit, nom. phase} \quad (13)$$

The nominated phase is the phase that is in violation with the limit, in this case water.

The water production rate and oil production rate, for each well in group PB1 is shown in Table 8. Note that the fraction of the water production rate for each well, is the same before and after the choking (blue numbers)

Table 8 - Water production for the wells in group PB1 (Fraction method)

Wells	Oil rate [Sm3/day] Before choking	Fraction of total production	Oil rate [Sm3/day] After choking	Fraction of total production	Water rate [Sm3/day] Before choking	Fraction of total production	Water rate [Sm3/day] After choking	Fraction of total production
Tot. prod.	623		449		2692		2000	
K1	228	0.367	161	0.358	1266	0.470	940	0.470
K4	183	0.294	134	0.298	664	0.247	493	0.247
B4	211	0.339	155	0.344	762	0.283	566	0.283

The water production rate for group PD2 and the water production rates for the wells K2, K3 and D4, are shown in Appendix B.

The water production rate for each well in group PB1, before and after the choking, is shown in Figure 43 .

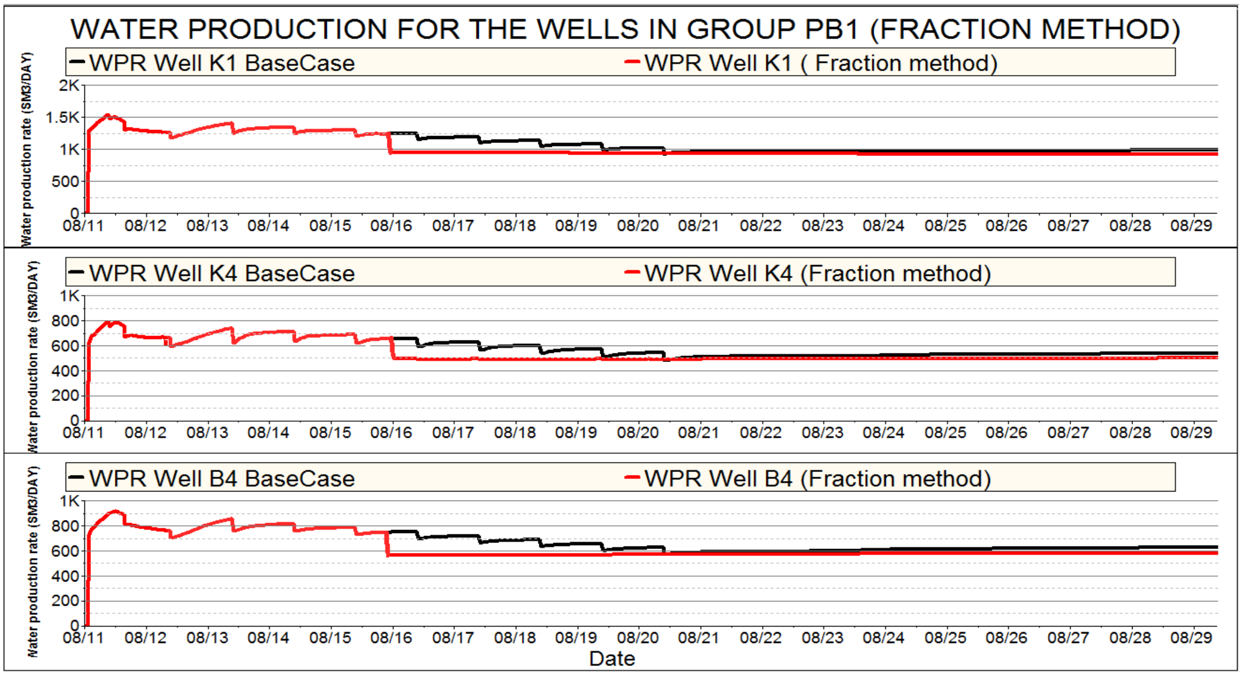


Figure 43 – Choking of each well in group PB1 (Fraction Method)

Note! The water rates, after the choking, in the figure matches the water rates calculated in Table 8.

The oil production rate and cumulative oil production for Norne is shown in Figure 44. The cumulative oil production is reduced with 1 063000 Sm3, compared to the base case.

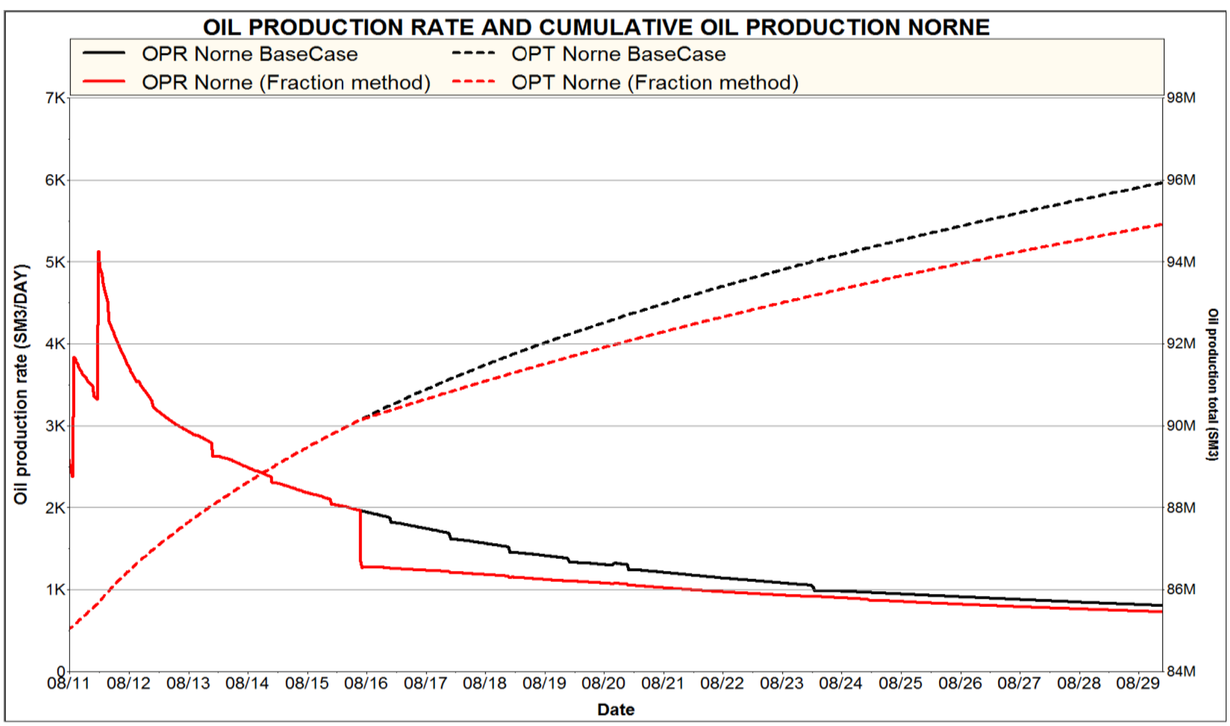


Figure 44- Oil production rate and total production rate for Norne (Fraction method)

5.2.3 Choking the production using Guide Rate on Groups (Group PB1/PD2)

The production was also choked by using Guide Rates on the groups PB1 and PD2. The groups were given a water limitation of 2000 Sm3/day.

To honor the limitation on Norne, the wells E3 and B1 needed to be choked too. They were sat under group control from the Norne field, and choked using Guide Rates. All the other groups were producing at potential (Recall Figure 41).

To understand how the use of Guide Rates works, the Guide Rate calculations will be shown in detail for group PB1.

The water production rate and total water production for Group PB1, compared to the base case are shown in Figure 45.

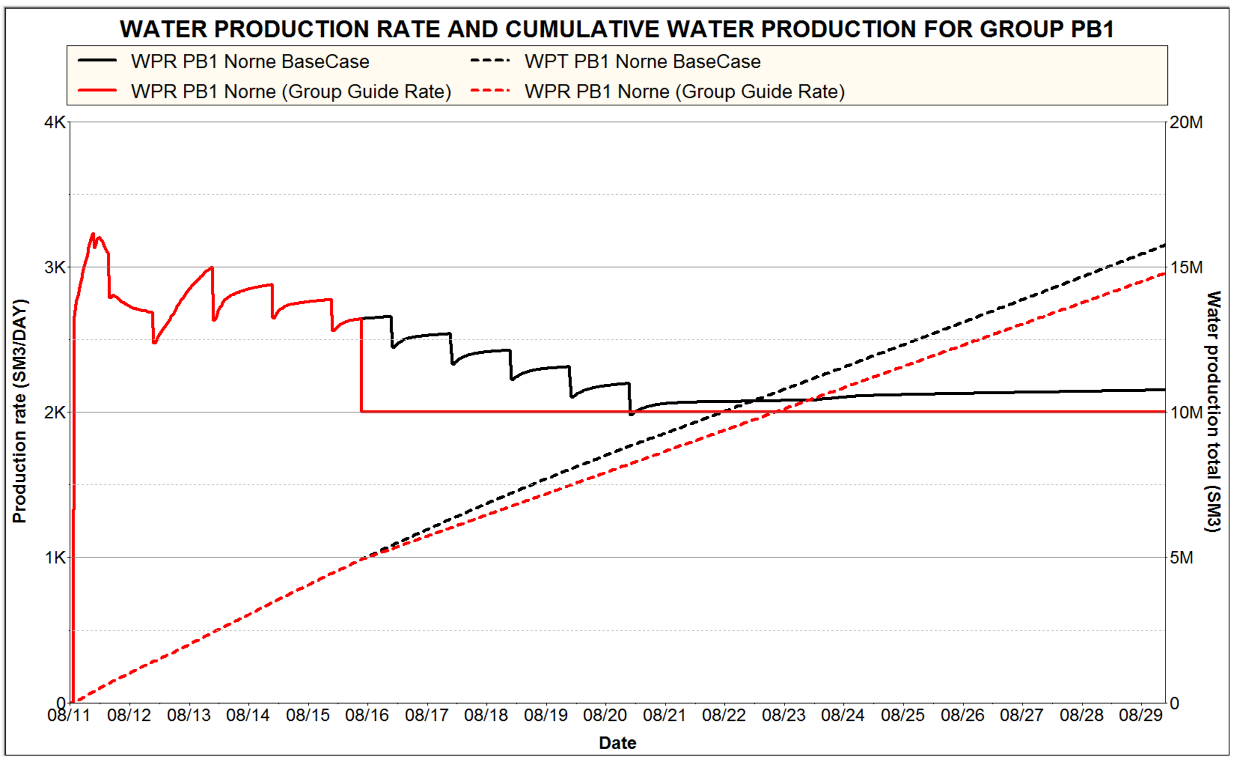


Figure 45- Water limitation applied to group PB1 (Guide Rate on groups)

For simplicity, the equation used to calculate the Guide Rates is stated below:

$$GR_{Wat} = \frac{(POT_o)^A}{B + C(R_1)^D + E(R_2)^F} \tag{14}$$

Where,

POT = Oil Potential

R1 = Oil-Water Ratio, from potentials

R2 = Gas - Oil Ratio, from potentials

A, B, C, D, E and F are used defined powers and coeffisients.

Recall that the coefficients could be changed to give the user the opportunity to influence on which wells that are choked. Three cases were made, shown in Table 9 (see subchapter 3.3.2.2).

Table 9 - Coefficients used in the different cases calculating Guide Rates

	A	B	C	D
Case 1	2	1	1	1
Case 2	1	1	2	2
Case 3	1	1	2	3

To illustrate how this method works, the calculated Guide Rates for the wells in group PB1 will be shown, using the coefficients from Case 3.

First, an overview of the oil production rate, oil potential, and oil/water ratio for the three wells is given, right before the group is choked, see Table 10.

Table 10 - Rates, potentials and ratios for the different wells in group PB1 before the wells are choked

Wells	Oil Prod. Rate [Sm3/day]	Oil potential [Sm3/day]	Water potential [Sm3/day]	OWR from potentials	Water Cut
K1	228	228	1266	0.18	0.85
K4	183	183	664	0.28	0.78
B4	211	211	762	0.28	0.78

As shown K1 has the highest oil potential, but also the highest water cut.

Note! Before the water limitation is applied to the group, the oil production rate and the oil potential rate is equal.

Table 11 shows how the calculated Guide Rates determines the wells water production rates.

Table 11 - Choking the wells using Guide Rates

Wells	Guide Rate from formula	Fraction of total Guide Rate	Water rate [Sm3/day] After choking	Fraction of water production
Tot. prod.	423		2000	
K1	169	0.40	798	0.40
K4	132	0.31	625	0.31
B4	122	0.29	577	0.29

The table shows that well K1 is producing 40% of the total water production from group PB1, while well B4 is producing 29%.

The distribution of the water production fractions for each well, using the coefficients from the other cases, is shown in Table 12. Recall that case 1 favors the wells with highest oil potential, while case 3 chokes the wells with high water cut.

Table 12- Each wells fraction of the total water production rate

Well	Case 1	Case 2	Case 3
K1	0.48	0.42	0.40
K4	0.28	0.30	0.31
B4	0.24	0.28	0.29

The result shows that well B4 produces a higher shear of the total water production rate when the wells with highest water cut are choked most.

The cumulative oil production for group PB1, for the three cases, is shown in Figure 46.

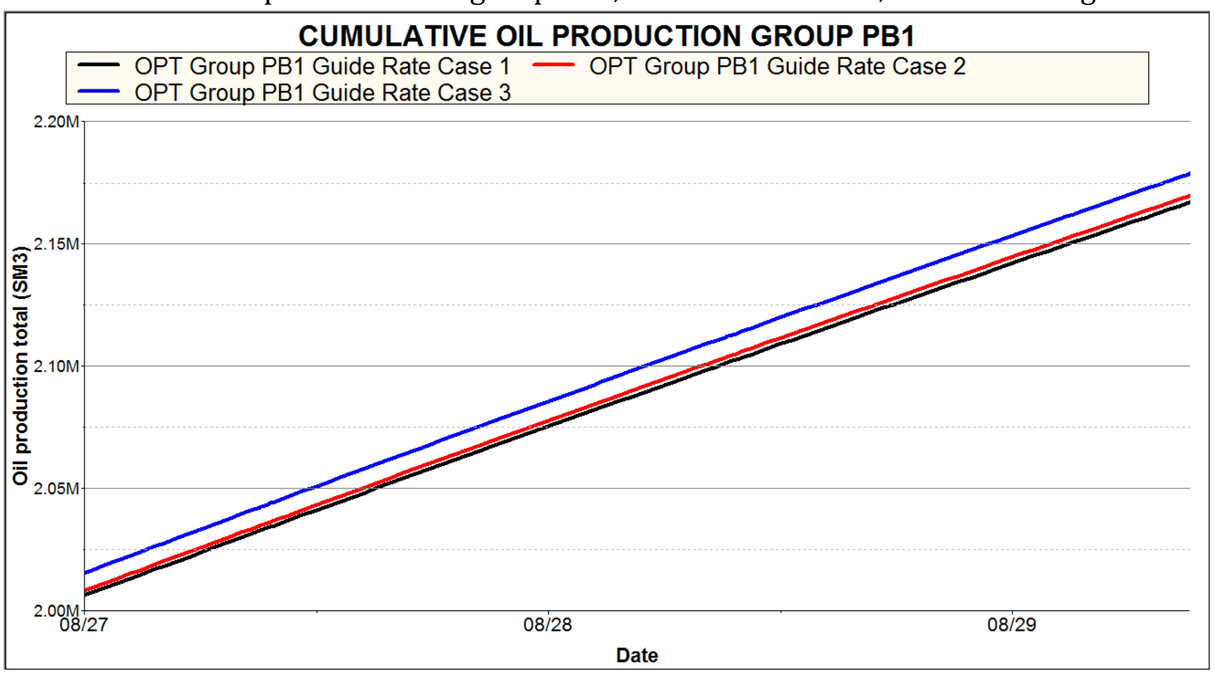


Figure 46- Oil Production Total for Norne (Group Guide Rate on Groups, three cases)

The comparison of the different cumulative oil production rates shows that the case where the high water cut wells are choked the most (case 3), gives the highest recovery of oil.

The total oil production for Norne, when Guide Rates were used on Groups (case 3), compared to the base case, is shown in Figure 47. The reduction in cumulative oil production is 697 000 Sm3.

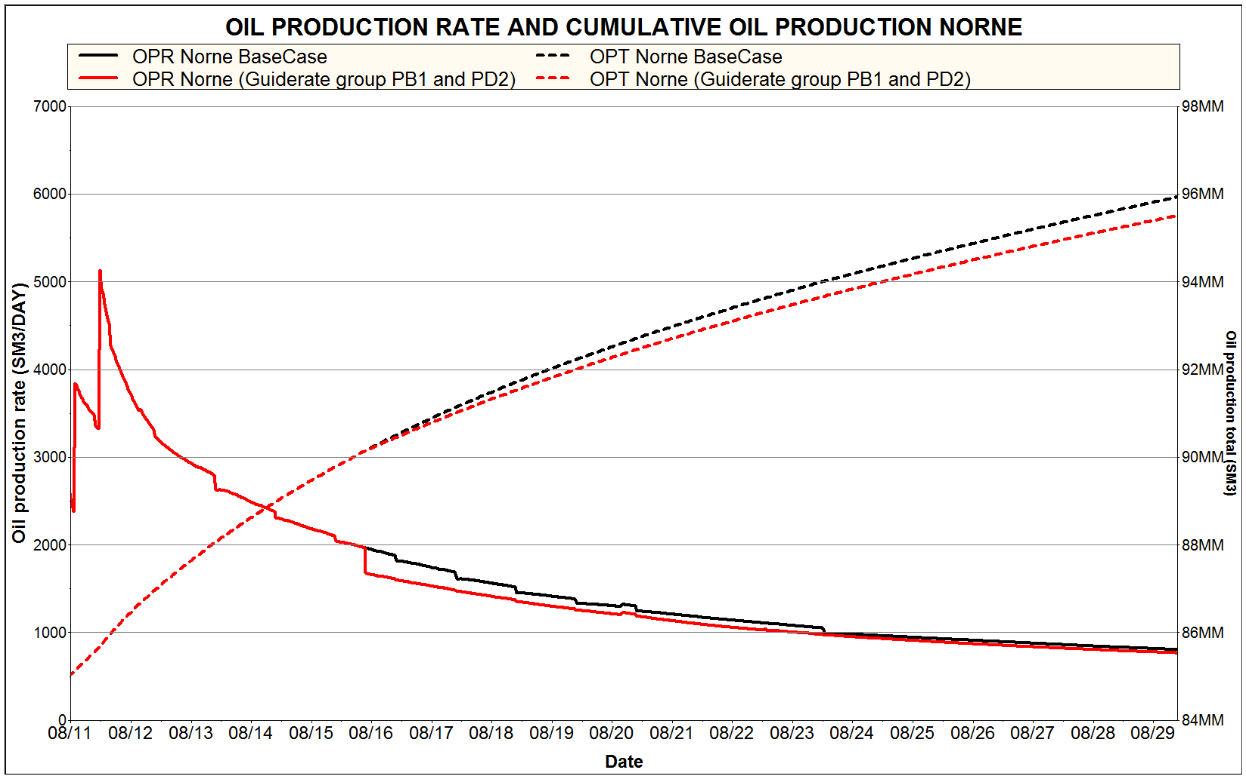


Figure 47-Oil production rate and cumulative oil production for the Norne main field (Guide Rate on groups)

5.2.4 Choke the production using Guide Rate on wells (Wells B1 and E3)

Another alternative considered was to choke the two wells with the highest water cut, using Guide Rates. These wells are E3 and B1, with a water cut of respectively 95% and 96%.

Here, the other wells are producing at the potential, while B1 and E3 are placed under group control, from the Norne Field, see Figure 48.

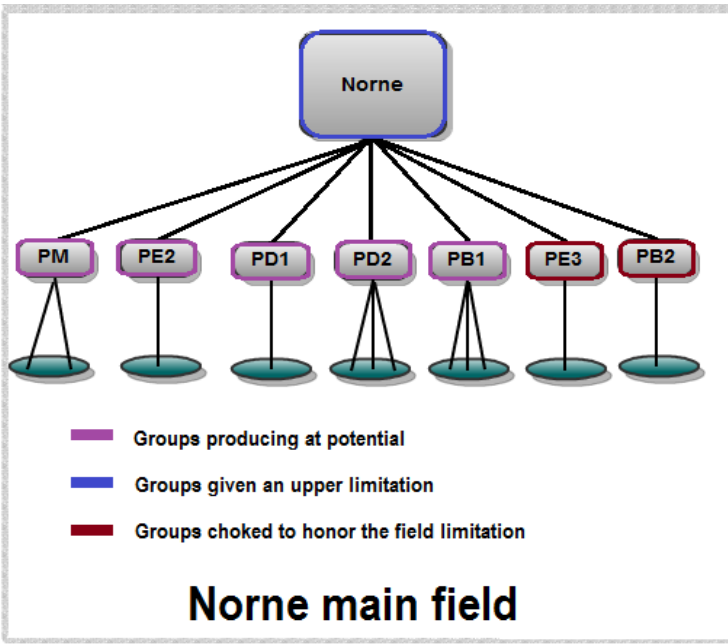


Figure 48 - Overview of which groups are given a limitation

This means that the two wells are allowed to produce the volume between the given constraints on the Norne field (15400 SM3/day of water, black line) and the volume the other wells are producing (dark purple), see Figure 49.

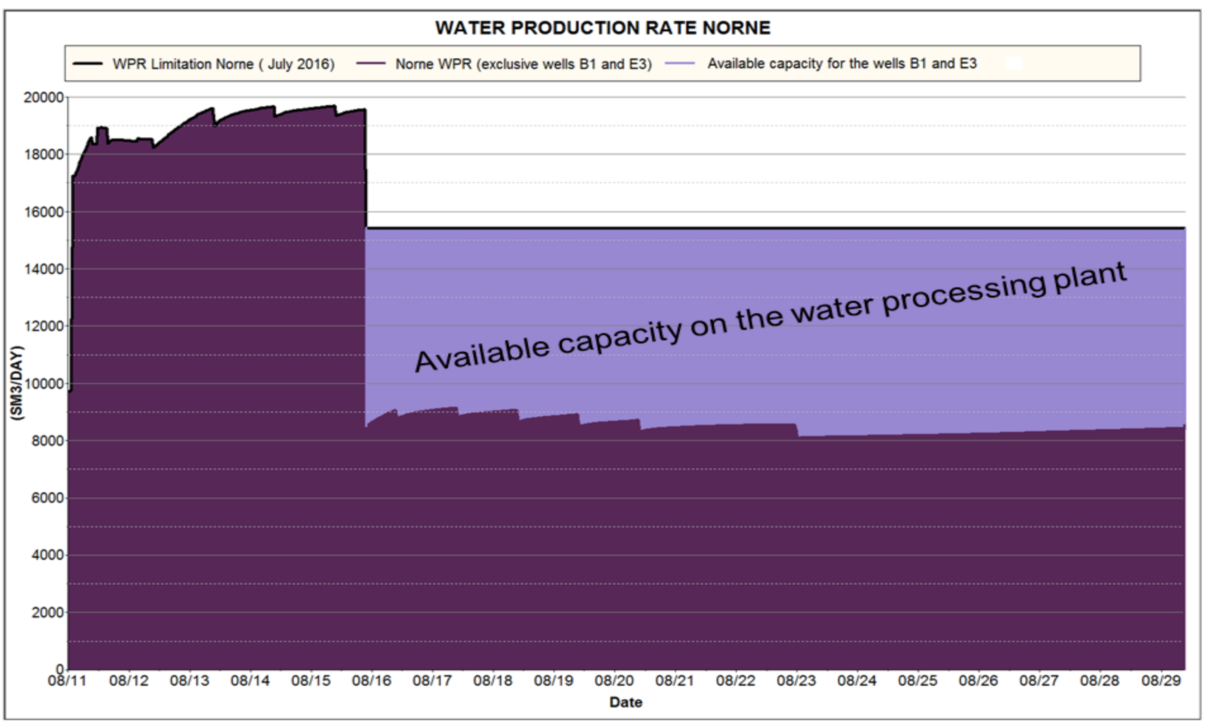


Figure 49 - Available capacity on the water processing plant for wells B1 and E3

Table 13 shows the Guide Rate fraction that determines how much water each well is allowed to produce of the available capacity (Coefficients from Case 3 is used).

Table 13 – Overview of the water production rate for well B1 and E3, 1st of July 2016.

	Guide Rate	Fraction	WPR [Sm3/day]	Fraction
Tot	0.007		6925	
E3	0.001	0.134	935	0.135
B1	0.006	0.866	5990	0.865

E3 is allowed to use 13.5% of the available capacity on the process plant, while B1 is allowed to use 86.5 %.

From Figure 49, it is shown that the available capacity on the water process plant, for the two wells B1 and E3, is approximately:

15400 Sm3/day (Norne limit) – 8500 Sm3/day (used by the other groups) = 6900 Sm3/day, in the beginning of July 2016. This is consistent with the total water production rate of 6925 Sm3/day for well B1 and E3 in Table 13.

The oil and water production rates for the two wells (using Guide Rates –case 3), compared to the base case are shown in Figure 50 and Figure 51. Guide Rates are calculated every time step.

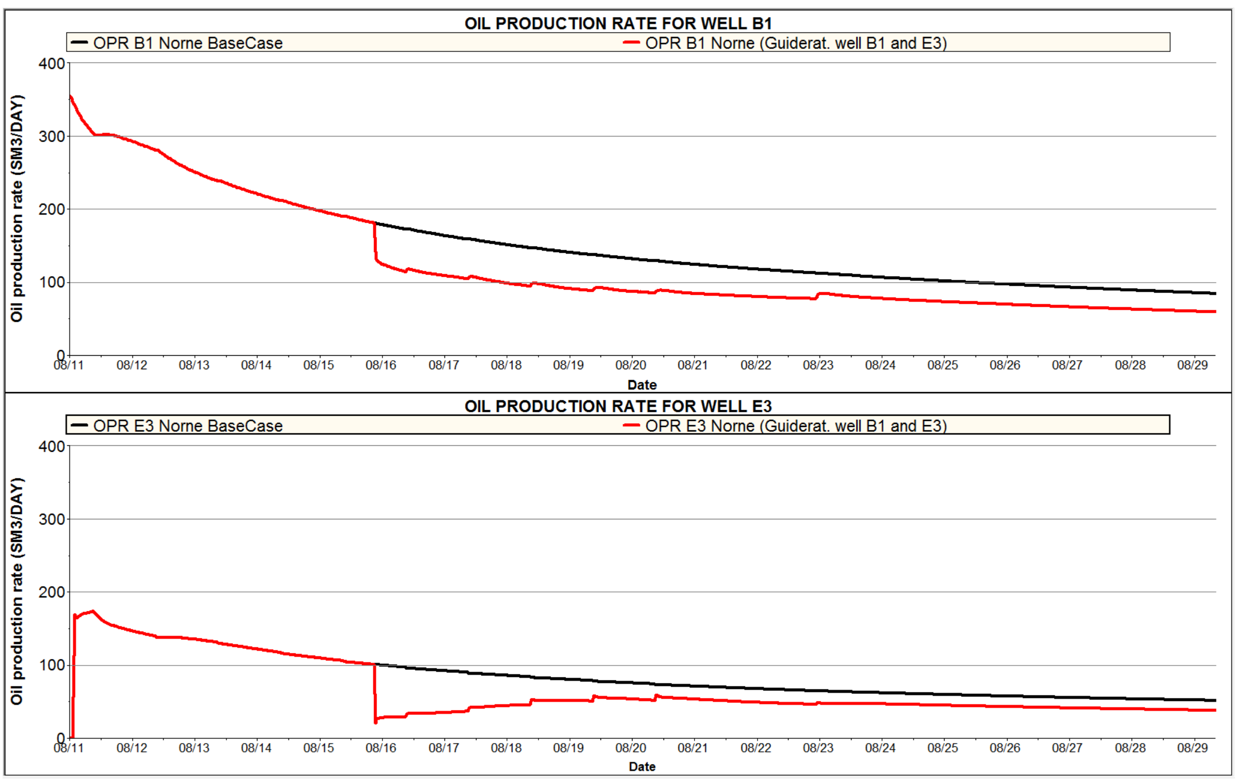


Figure 50- Oil rate and cumulative oil production for the wells B1 and E3 (Guide Rates on wells)

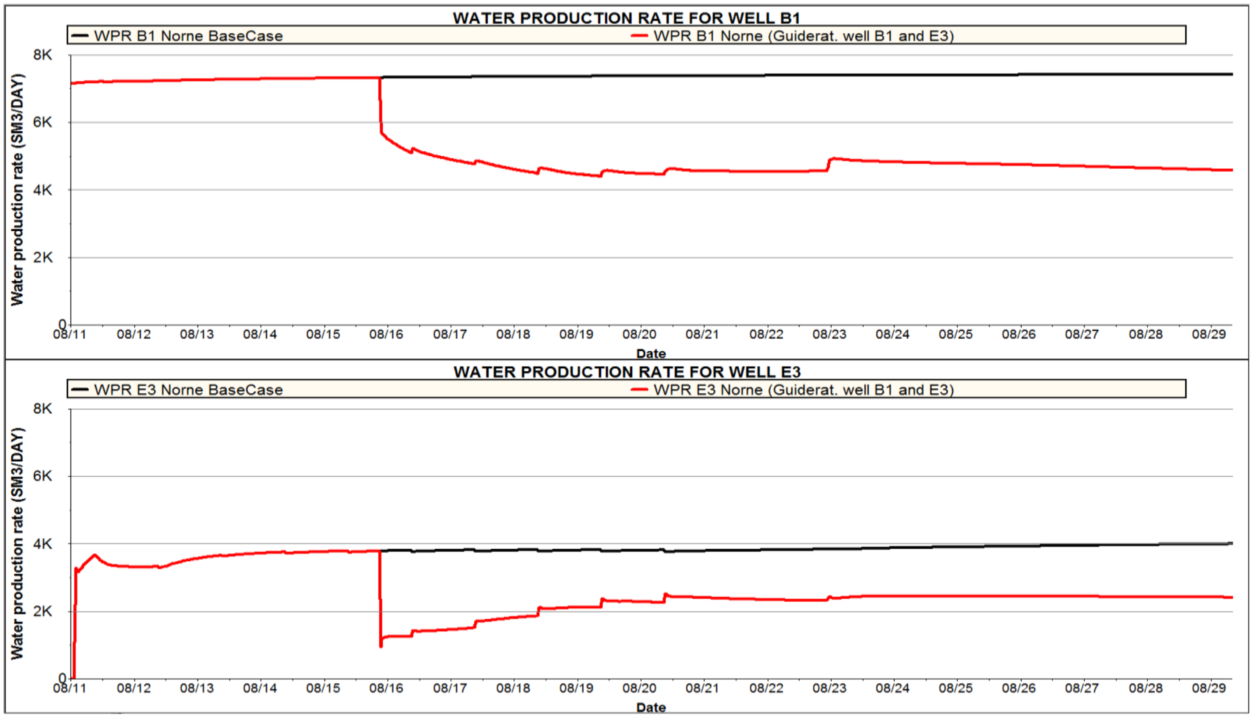


Figure 51- Water rate and cumulative water production for the wells B1 and E3 (Guide Rate on wells)

Calculating the Guide Rates is also done using the coefficients in Case 1 and 2. Each wells fraction of the total available capacity is shown in Table 14.

Table 14- Fraction of the total water production for well E3 and B1, three different cases

Well	Case 1	Case 2	Case 3
E3	0.039	0.131	0.135
B1	0.961	0.869	0.865

B1 is the well with the highest water cut. In Case 1, well B1 is allowed to produce 96.1 % of the total water production, while it is only allowed to produce 86.5 % in Case 3.

To compare the cumulative oil production in the three cases, the wells were grouped together in the data file. The group is called PE3B1.

The total oil production for the three cases are shown Figure 52.

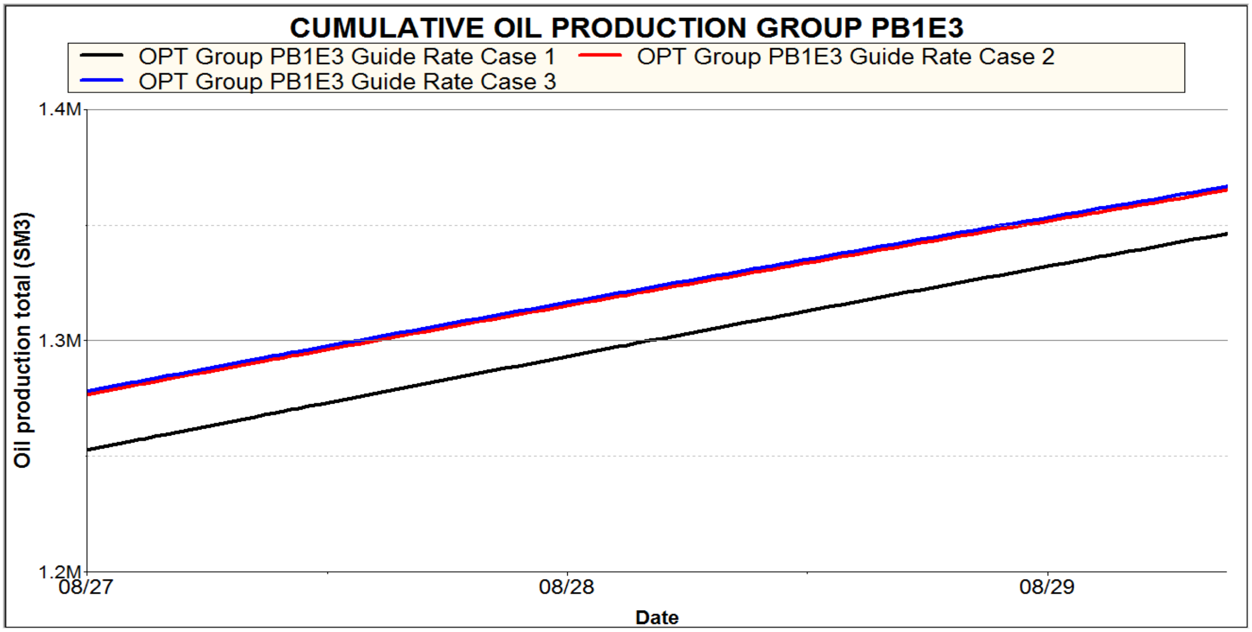


Figure 52 - Oil Production Total for group PB1E3 (Group Guide Rate on wells, three cases)

The figure above shows that the highest cumulative oil production is gained in Case 3. Again, the case there the high water cut wells are choked most gives the highest oil recovery.

The total oil production on the Norne main field (using coefficients for Case 3) compared to the base case, are shown in Figure 53. The cumulative oil production is reduced with approximately 281 000 Sm3 of oil.

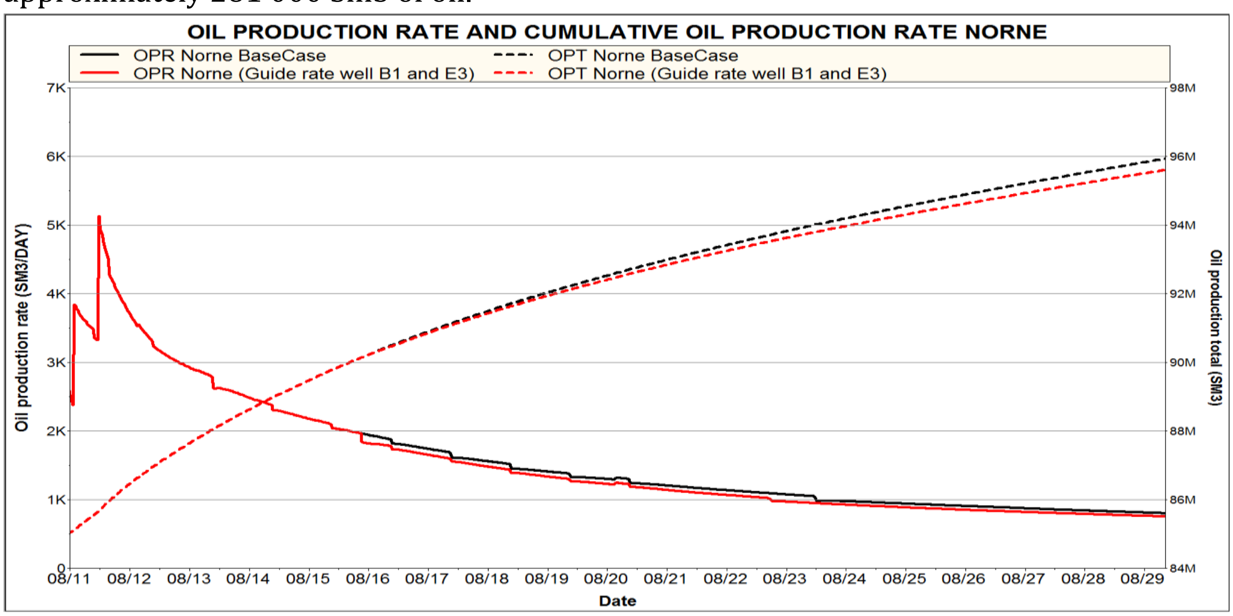


Figure 53- Oil production rate and cumulative oil production for the Norne main field (Guide Rate on wells)

5.2.5 Choking the production using priority rules (wells B1 and E3)

The last alternative considered was to choke the two wells with highest water cut, using Priority Rules.

Each well is assigned a priority number, and the wells are turned on in decreasing order of priority, where the well with the highest priority goes first.

As for the case where Guide Rates are used on wells, the other wells are producing at their potentials, while B1 and E3 are placed under group control (Recall Figure 48).

For simplicity, the priority equation is stated below:

$$\text{Priority} = \frac{A + BQ_o + CQ_w + DQ_g}{E + FQ_o + GQ_w + HQ_g} \quad (15)$$

Where,

Q_o, Q_w and Q_g are the well's potential oil, water and gas production rates

A-H are user defined coefficients

Recall that two cases were created, where the first favors the wells with high oil potentials (Case 1), and the second favors the wells with low water cut (Case 2), see Table 15.

Table 15 - Coefficients used in the different cases, calculating Priority numbers

	A	B	C	E	F	G	H
Case 1	0	1	0	1	0	0	0
Case 2	0	1	1	0	0	1	0

To illustrate how the use of Priority Rules works, the choking of the wells B1 and E3 to honor the water limitation on Norne (using the coefficients from Case 2) has been shown.

This case chokes the well with highest water cut. The water cut for the two wells, from the base case, is shown in Figure 54.

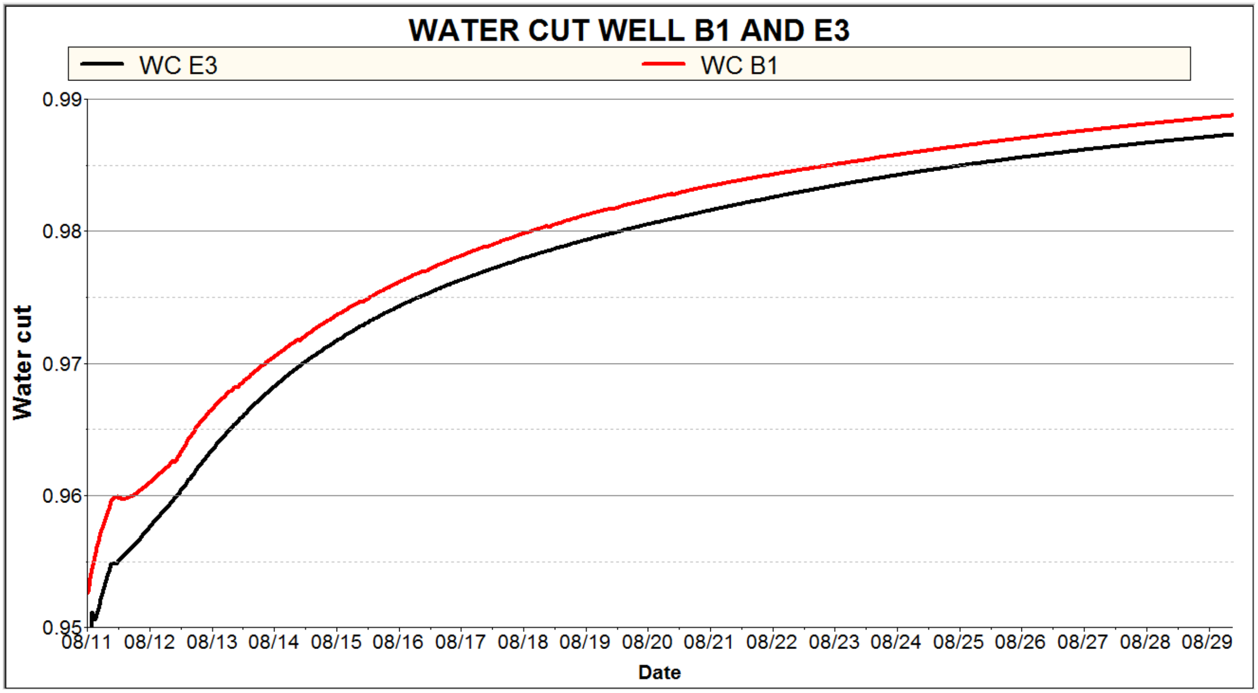


Figure 54 - Water cut for the wells B1 and E3, base case

The figure shows that well B1 has the highest water cut, and will be choked back first. One can imagine that it is possible to predict which wells that are going to be choked, only by looking at the plots of the water cut. In this case, it seems like only B1 will be choked.

The production rates for the wells B1 and E3 are shown in Figure 55 and Figure 56, using the Priority equation from Case 2.

It shows that well B1 is choked back first, but when the Priority number is recalculated after 100 days, B1 is opened and well E3 is choked.

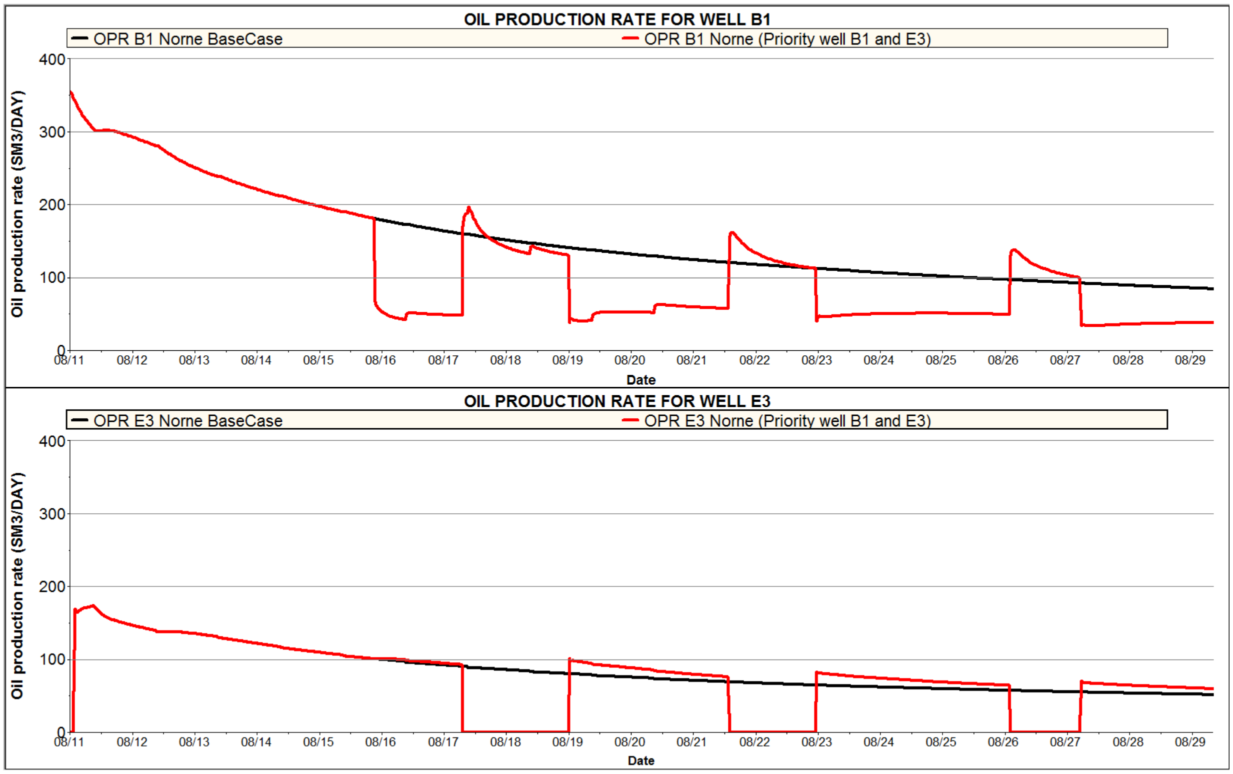


Figure 55 - Oil production rate for the wells B1 and E3 (Priority rules)

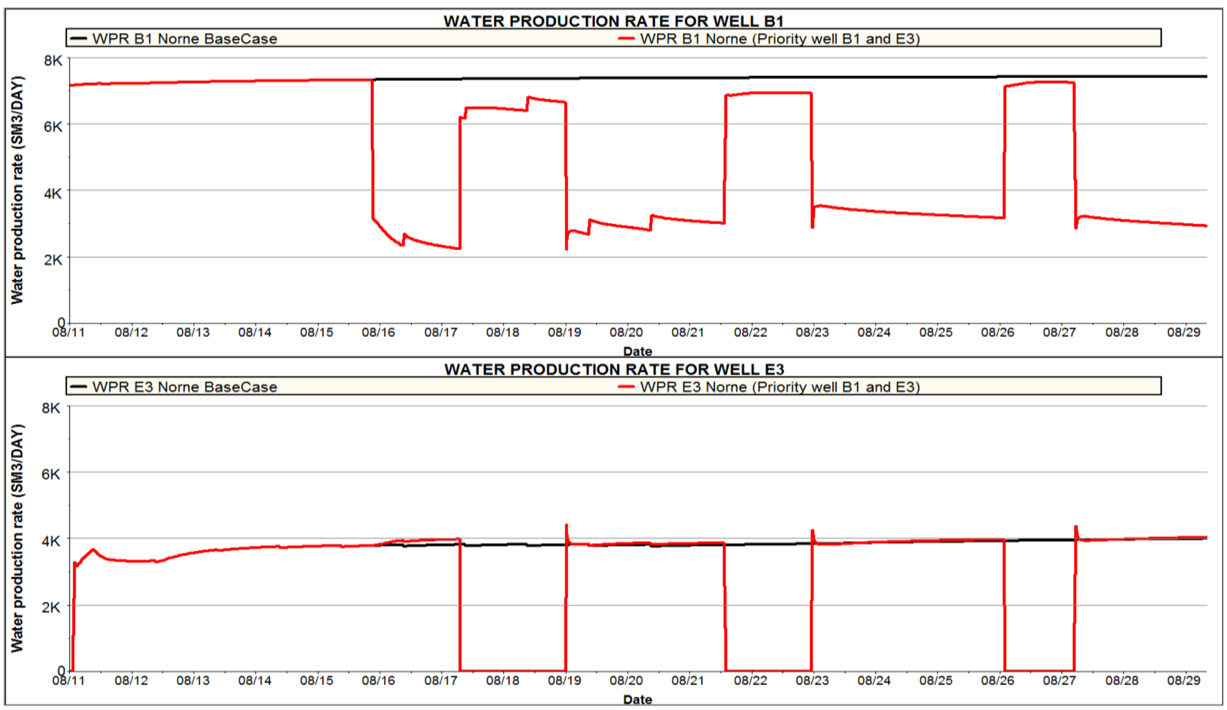


Figure 56 - Water production rate for the wells B1 and E3 (Priority rules)

This can be explained by looking at the water cut for B1 when it is choked, compared to the base case, see Figure 57.

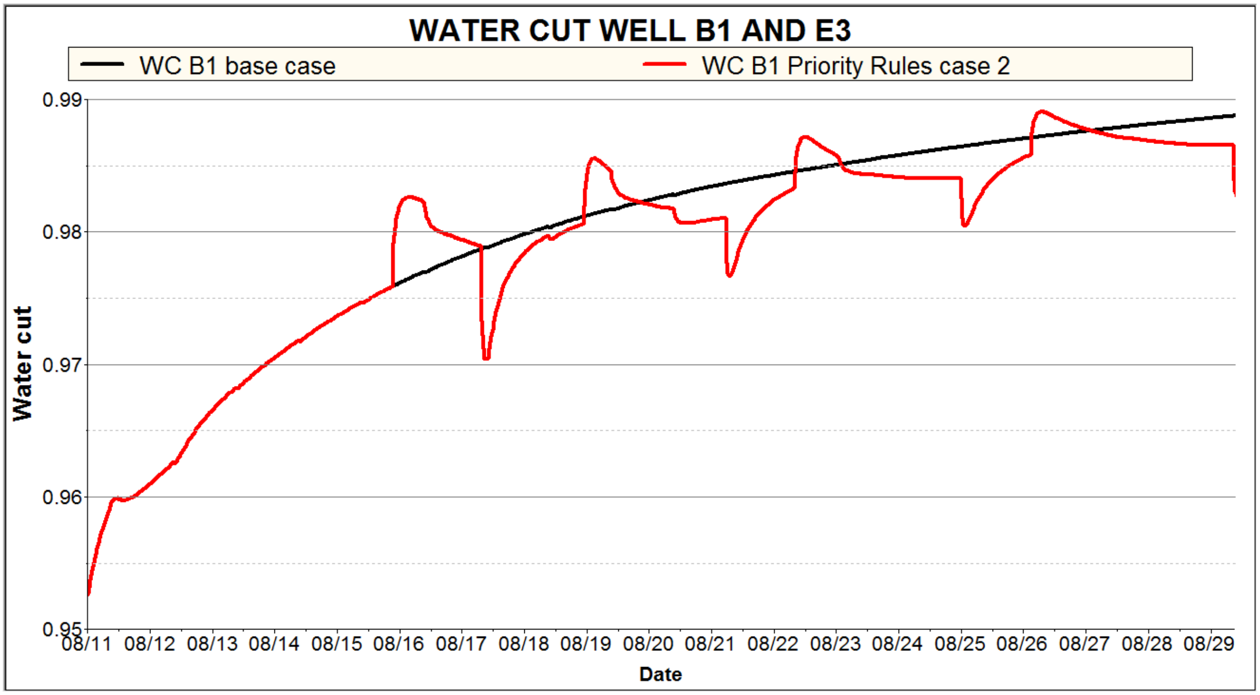


Figure 57 - Changes in the water cut for well B1 when the water limitation is applied (Priority Rules Case 2)

As shown, the water cut changes when the well is choked, and therefore well E3 is choked when the priority number is recalculated.

The priority number decides which well is producing at a given time. In this case, the priority number is recalculated every 100 day.

The frequency of the oil potential calculation is an input in the Eclipse data file. The time step between each calculation did not change the total cumulative oil production in this case, but had an effect on which wells that are producing at a given time, see Appendix C.

Again, the wells are grouped together in the group PB1E3 to compare the cumulative oil production, using the Priority equation form Case 1 and Case 2. The result is shown in Figure 58.

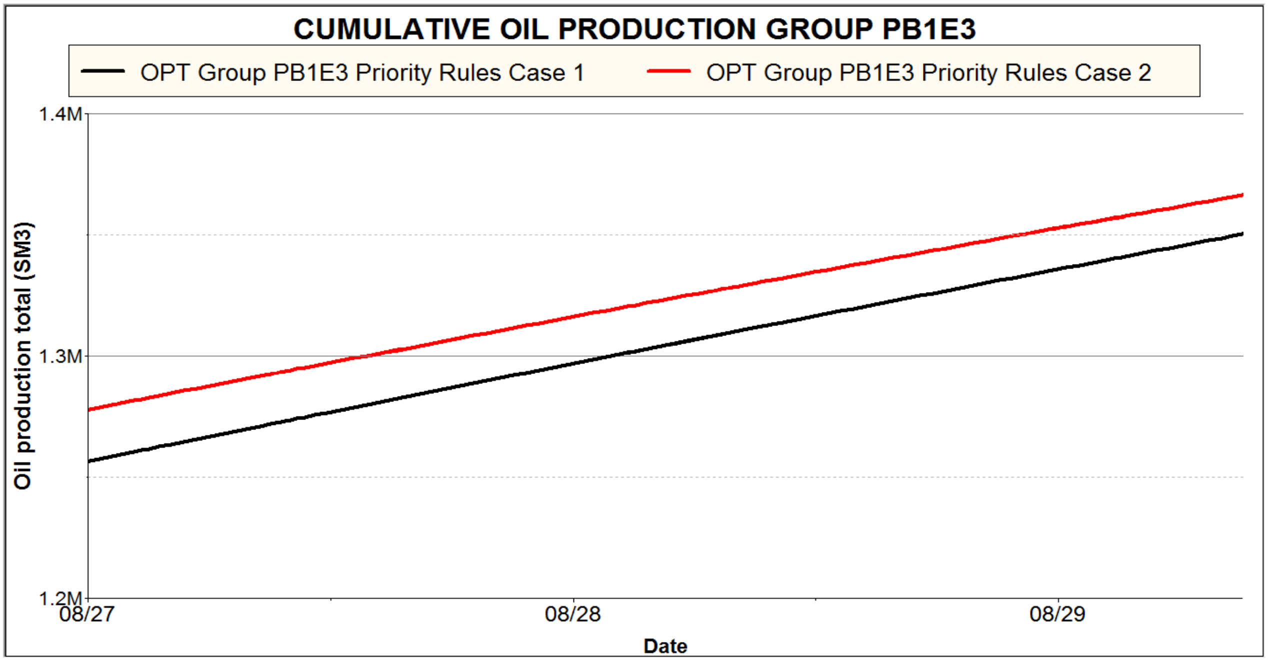


Figure 58 - Oil Production Total for group PB1E3 (Priority Rules, two cases)

Again, this shows that the case where the high water cut wells are choked back gives the highest recovery of oil.

The total oil production on the Norne main field using Priority Rules (case 2), compared to the base case, are shown in Figure 59. The reduction in the cumulative oil production is 289 000 Sm3 of oil.

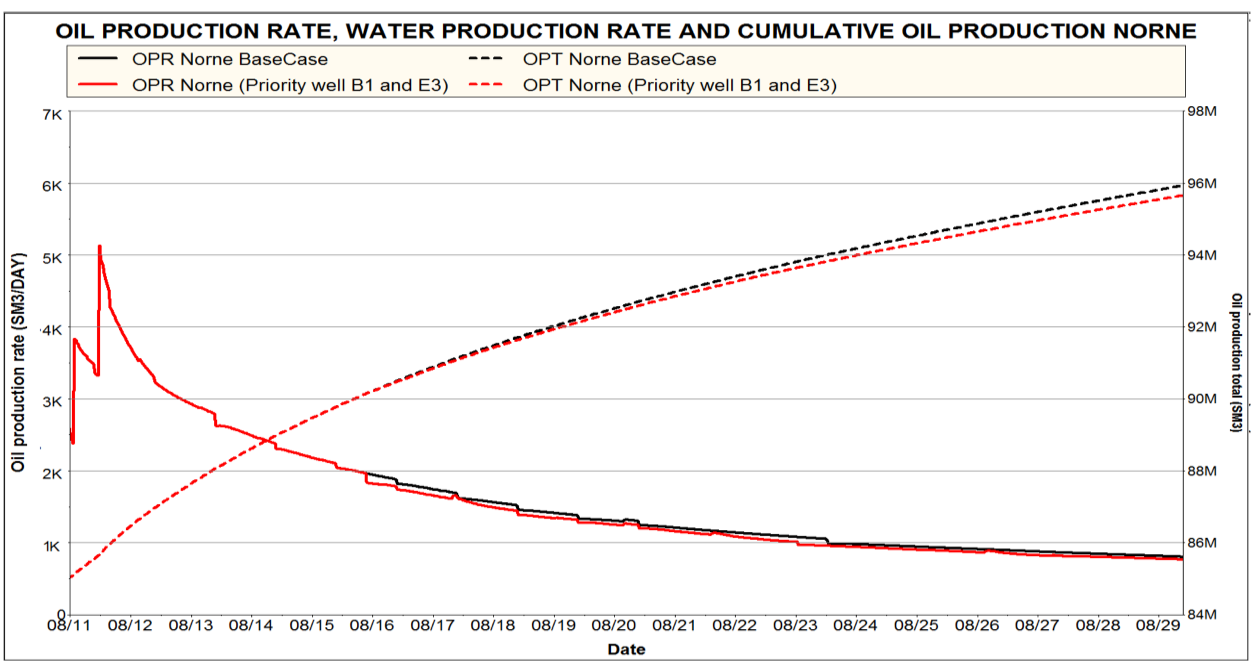


Figure 59 - Oil production rate and cumulative oil production for the Norne main field (Priority rules)

5.2.6 Comparison of the different methods

Several methods have been explored, when choking the water production in the Norne stand-alone model.

The main difference between the methods is related to how the wells are choked.

The Fraction Method chokes all the wells, depending on how much produced water each well was contributing with originally.

The use of Guide Rates may favor wells with high oil potential, or choke wells with highest water cut. The wells are not choked equally, but all the wells are contributing with production.

The use of Priority Rules chokes the wells more "drastically". This method also has the possibility to favor wells with high oil potential or choke wells with highest water cut, but the well with the lowest priority number is choked a lot, and in some cases shut completely.

Figure 60 shows the cumulative oil production for the Norne main field for each of the different methods compared to the base case.

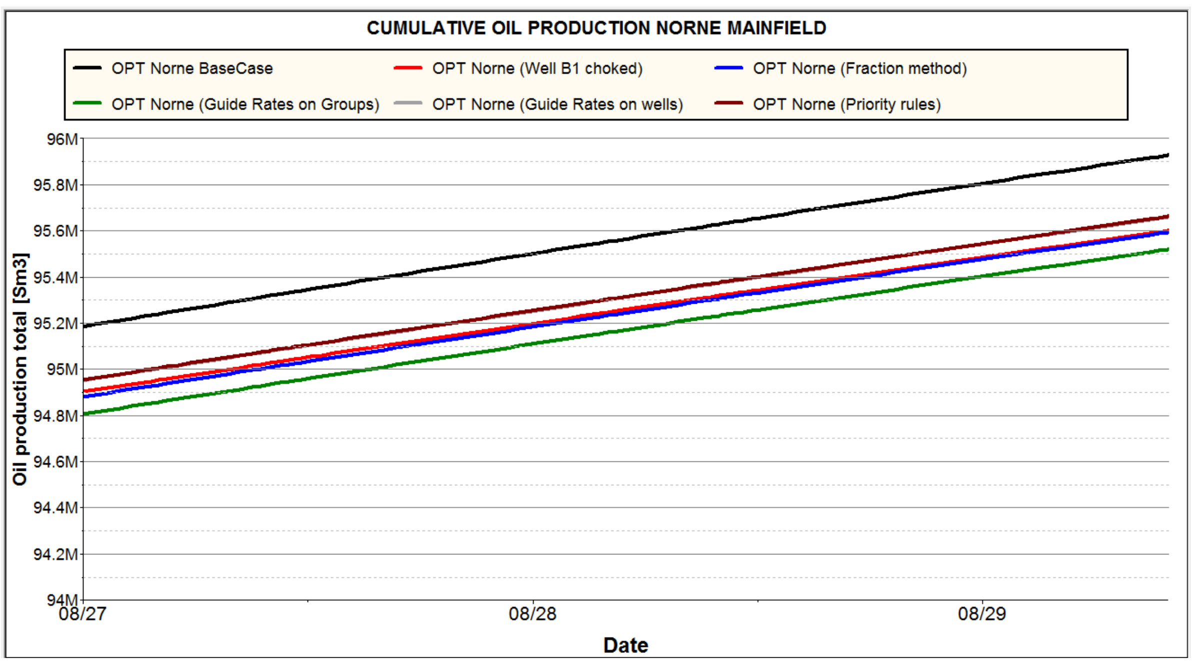


Figure 60 - Comparison of the total oil production for the different methods of choking the production

The figure shows that choking wells with the highest water cut, using Guide Rates (Case 3) gives the highest oil recovery. This result is shown numerically in Table 16.

Table 16 - Numerical overview of the cumulative oil production for the different methods in MSm3

Method	Cumulative oil production [MSm3]	Difference from the base case [MSm3]
Base case	96216	-
Well B1 choked	95871	345
Fraction method	95153	1063
Guide Rate group	95519	697
Guide Rate well	95935	281
Priority rules	95927	289

5.3 Coupled Model Optimization

Sensitivity analysis has been performed on the Norne and Urd stand-alone models. The restrictions are now performed on the RC-model.

The water constraint, which previously was applied on Norne, is now applied to the whole field. The constraint is 30 000 Sm3/day, which is the water treatment capacity. The constraint is honored using Guide Rates (Case 3) on the high water cut Norne wells E3 and B1.

It is shown in Figure 60 that choking wells with the highest water cut gives the highest cumulative oil production (see subchapter 5.2.6).

To increase the total gas production rate on the Norne FPSO, it is important to optimize the usage of the gas processing plant. For the coupled model, the gas lift on Urd will be minimized (see subchapter 5.1), allowing Alve to produce more.

It is not possible to use the Gas Lift Optimization facility in Coupled Reservoirs, so to minimize the gas lift on Urd, an alternative method is used. This method is described below:

1. The ActionX keyword is used to check if the wells on Svale are shut. If a well is open, the gas lift is reduced to 50 000 Sm3/day.

2. After two days, the same routine is repeated again. If the well is producing it is OK, but if the well is shut, the gas lift is increased to 60 000 Sm3/day

3. Two days later, the routine is repeated again. If the well is producing it is OK, but if the wells is shut, the gas lift is increased to 100 000 Sm3/day.

This routine is applied to the wells on Svale once every year. In this way, the wells are assigned a minimum amount of gas lift, just enough to keep them flowing. How the ActionX routine is looking in the data file, can be found in Appendix D.

50 000 Sm3/day is chosen as the minimum limit of gas lift a well can be assigned, because this is the lowest gas lift rate in the Vertical Flow Performance (VFP) curves, used for the wells.

The minimized gas lift on Urd, using the ActionX, is shown in Figure 61.

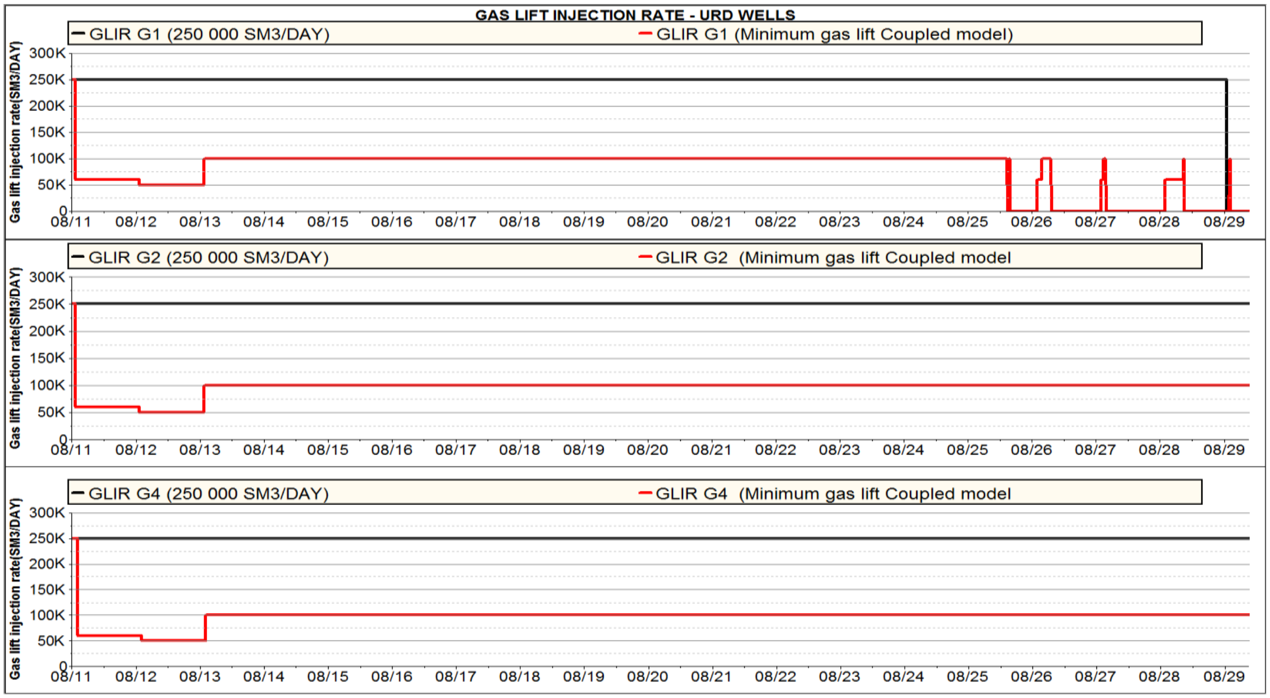


Figure 61 – Gas Lift Injection Rate on Svale (Minimized, Coupled Model)

The space released on the process plant will be equal to the volume between the black and the red line in the figure above.

It is believed that by reducing the gas lift on Urd, and let Alve produce more, an increase in the total gas production rate can be observed.

Figure 62 shows the Alve gas production rate and cumulative gas production, when the field is producing at potential. In August 2023 the production dies due to low reservoir pressure.

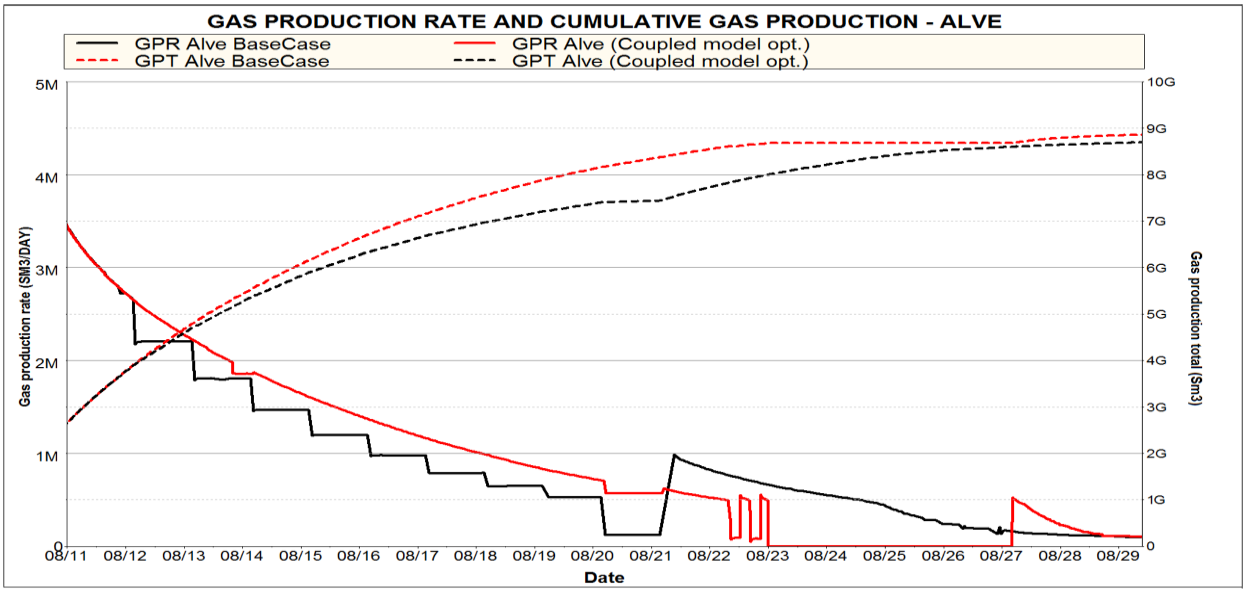


Figure 62 - Gas production on Alve (Coupled model)

Due to the increase in the gas production, Alve also produces more condensate. Therefore the oil production on Alve increases, too. This is shown in Figure 63. The total oil production increases with approximately 78 000 Sm3/day.

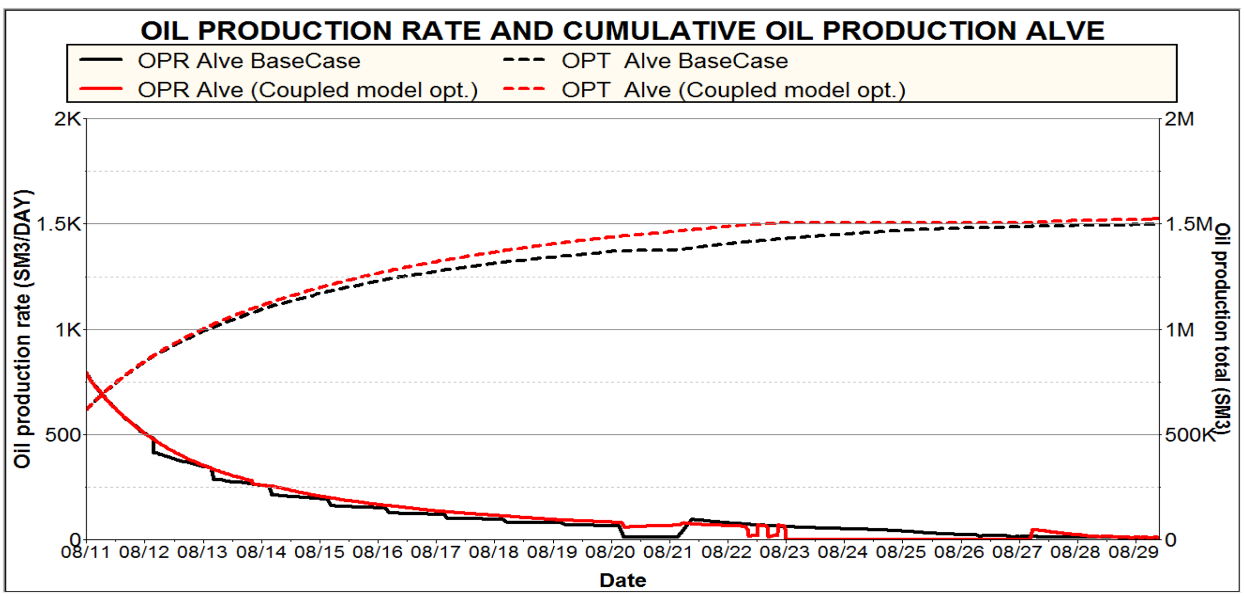


Figure 63- Oil production on Alve (Coupled model)

Even though the water constraint is applied to the field, only Norne wells B1 and E3 are allowed to be choked.

This decreases the oil production on Norne, see Figure 64. The reduction between the base case and the optimized coupled model is approximately 205 000 Sm3/day.

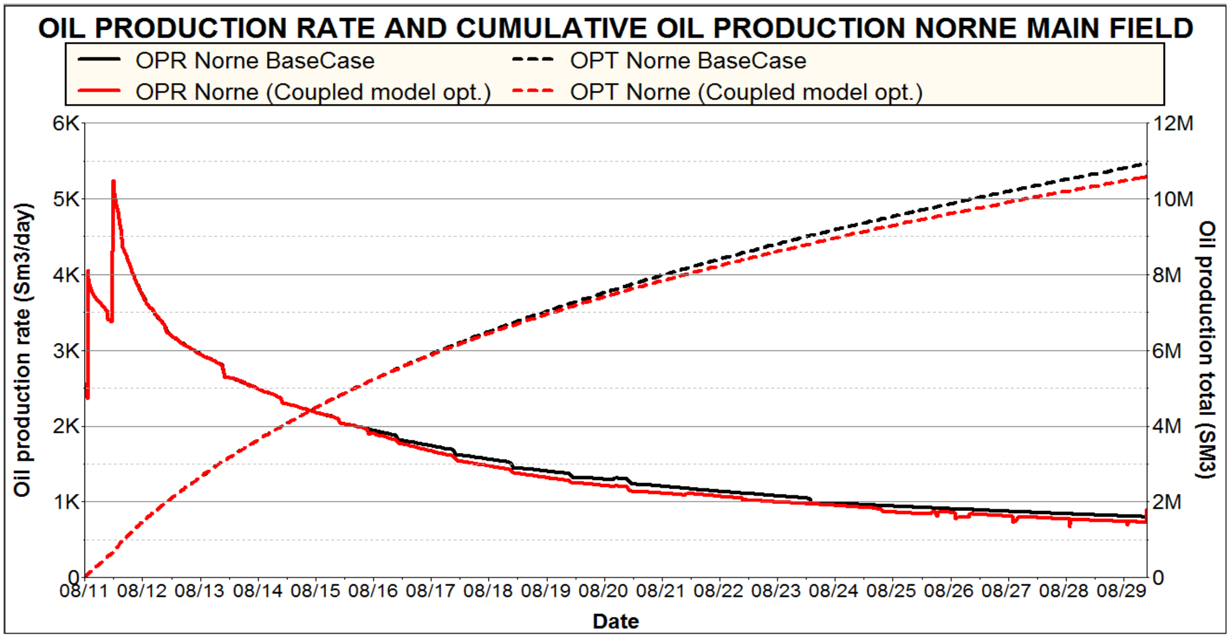


Figure 64 - Oil production Norne main field (Coupled model)

5.3.1 Combined production plots

As mentioned, one of the advantages with a coupled model is the opportunity to make combined production plots.

The water limitation was applied to the field, in July 2016, see Figure 65.

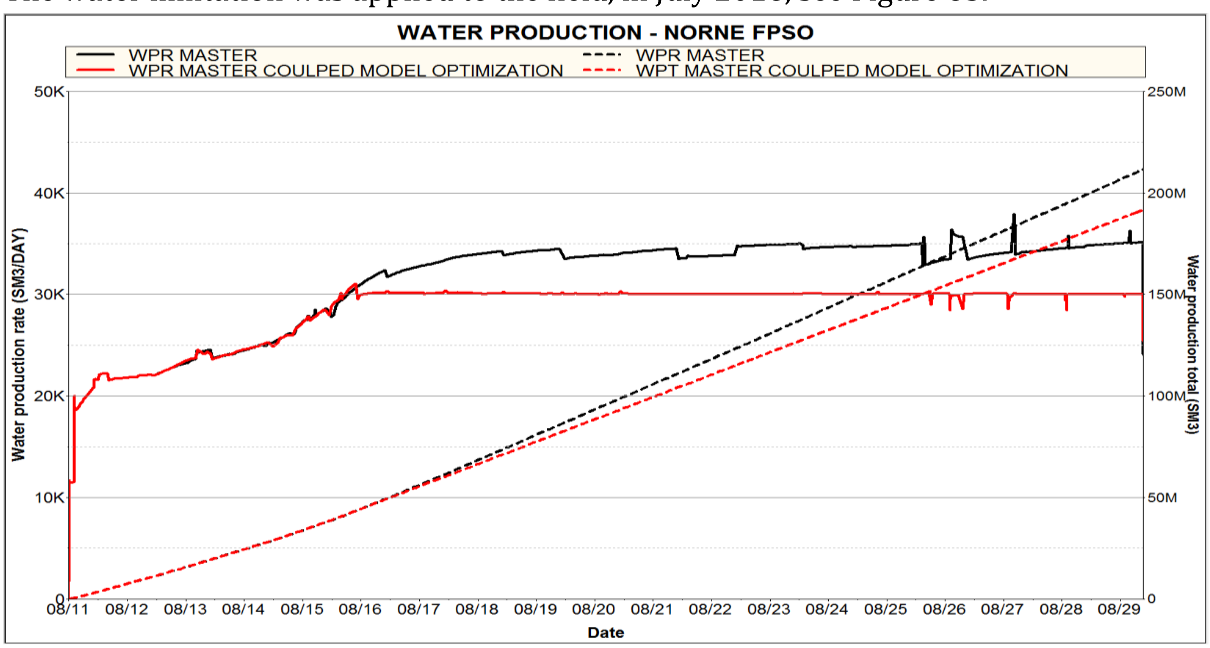


Figure 65 - Water production for the Norne FPSO (optimized case compared to base case)

Figure 66 shows that the gas production rate increases until August 2020. This is because Alve is allowed to produce at its potential. After 2020, the production from Alve dies, due to low reservoir pressure.

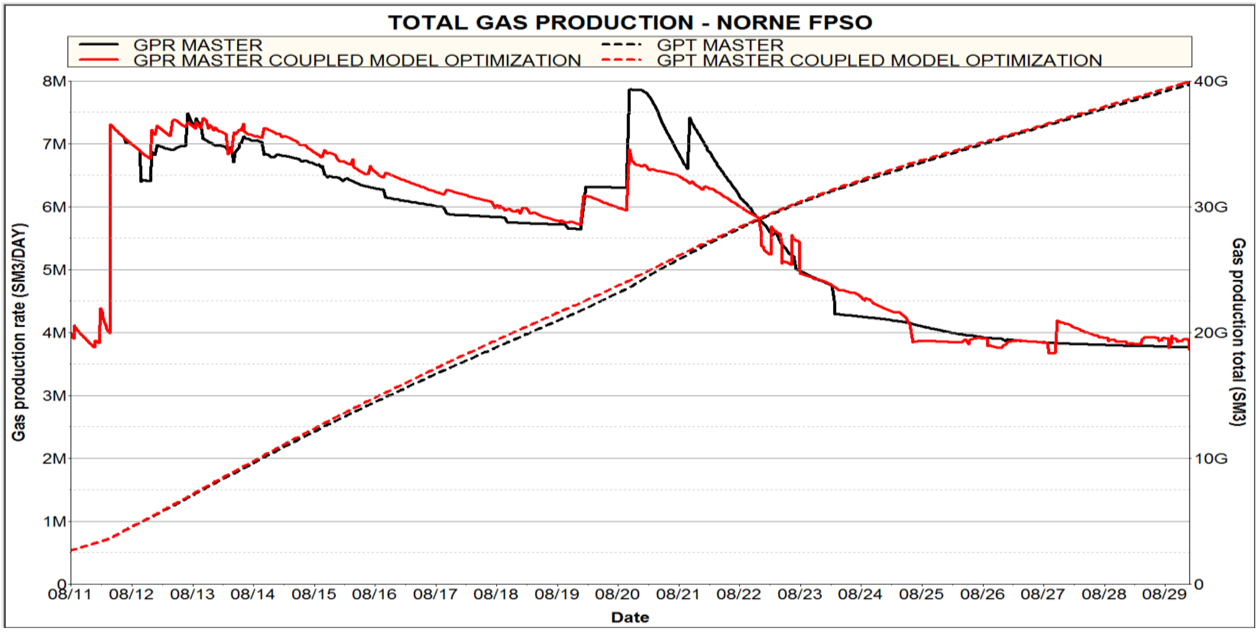


Figure 66 - Gas production for the Norne FPSO (optimized case compared to base case)

In Figure 67, the oil production rate for the Norne FPSO RC-model is shown. The case where the production is optimized (red line) is compared with the base case. The cumulative oil production in the optimized case is reduced with approximately 247 000 Sm3, compared to the base case.

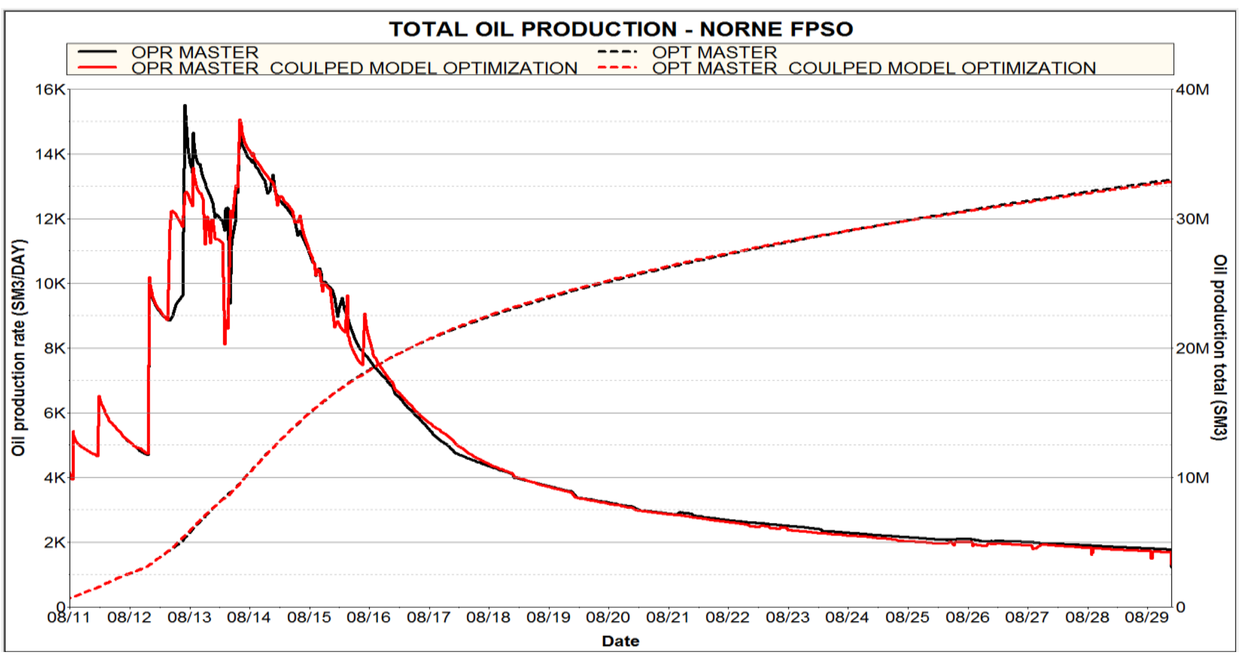


Figure 67 - Oil production for the Norne FPSO (optimized case compared to base case)

An overview of how much the cumulative oil production for each of the satellites fields have increased or decreased, compared to the base case, is shown in Table 17.

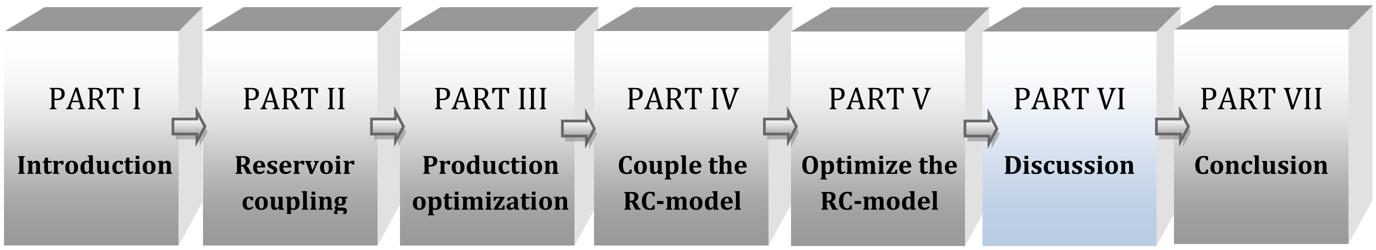
Table 17- Overview over the reduction and increase in cumulative oil production for the different satellites

Wells	Cumulative oil production Base case [1000 Sm3]	Optimized case [1000 Sm3]	Difference [1000 Sm3]
RC-model	33000	32754	-247
Norne	11000	10795	-205
Alve	1492	1570	78
Urd	3264	3142	-122
Skuld	16436	16436	0
Marulk	888	888	0
Total diff			-248

Note that the total reduction in the cumulative oil production for the RC-model is equal to the total reduction for all the satellites (blue numbers).

The reduction in the cumulative oil production for Norne is less than the reduction gained when using Guide Rates on the wells B1 and E3 in the stand-alone model (reduced with 281 000 Sm3, see Figure 53).
The explanation lies in the limitations applied to the models. In the stand-alone model, Norne were given a water rate limitation of 15400 Sm3/day. In the RC-model, Norne is under control of the field. This allows Norne to produce more than the 15400 Sm3/day, depending of the capacity of the water treatment plant.

PART VI
DISCUSSION



In Part VI, Discussion, there will be an evaluation about the limitations and weaknesses regarding the models used in this thesis.

There are uncertainties related to the simulation models, which may influence the simulation results. These uncertainties will also be discussed.

6.1 Discussion of the simulation results

The results from the RC model indicate that it is possible to constrain the water production on Norne, minimize the gas lift on Urd, and at the same time maintain the oil production rate (See subchapter 5.3).

To say something about the validation of the simulation results, the weaknesses and limitations of the models used needs to be discussed.

6.1.1 Weaknesses of the simulation models

When evaluating the simulation results, uncertainties related to the stand-alone models needs to be taken into consideration.
Three main uncertainties need to be discussed further:

i) Water cut on the Norne main field.

The water cut gained from the Norne stand-alone simulation model is slightly different from the water cut observed in the field. However, since the water cut from all the wells is relatively high, the difference is not believed to have a huge influence on the simulation results.

ii) Gas lift on Urd.

In the simulation model, each well is assigned a gas lift of 250 000 Sm3/day, to keep the wells producing. In reality, this number is lower. There are uncertainties regarding the effect of gas lift, in the Urd stand-alone simulation model. It is unknown whether the effect of injecting one additional cubic meter of gas into the Svale wells, in the simulation mode, will reflect the effect observed in reality.

The gas lift rate used in the Urd stand-alone model should be consistent with the reality. This number will influence the available capacity on the gas process plant when the gas lift is set to a minimum, and thereby influence the additional amount of gas Alve is allowed to produce.

iii) Closing an Urd producer

As seen in Figure 33, the liquid production for Urd increases when well G1 dies. Closing G1 has not been tested in reality, but it seems rather unlikely that closing one producer will lead to an increase in the liquid production rate for the field.

6.1.2 Limitations of the RC model

There are some weaknesses regarding the use of RC-models. It is not believed that these weaknesses will influence the validation of the simulation results, but it is rather important to understand these limitations when using the model.

First of all, not all facilities that Eclipse provides are applicable on a RC model, and Schlumberger will not guarantee that all the facilities in Eclipse can be used on RC models in the future (Eclipse Technical description). Among these are the Gas Lift Optimization Facility and the Priory Option.

Recall that for the Priority Option, the user has the opportunity to turn wells on in decreasing order of priority (See subchapter 3.3.2). The master reservoir is not directly connected to the individual wells in the Slave Reservoirs, so it does not have the authority to shut or open wells in the slaves.

There are also limitations regarding global rate targets applied to a RC-model. These targets cannot be met exactly. The master apportions a rate target among the master Groups, based on each group's flow capability at the *start* of the time step. The flows from the slaves are reported at the *end* of the time step, and this could lead to a significant error from the target rate, if the flow rate in the slave group changes during the master's time step. One way to handle this problem is to decrease the master run's time step.

6.2 Validation of the simulation results

It is important to question and be critical to the results gained from a simulation model, and compare the simulated production rates with what is actually observed in the field, using production data and well tests.

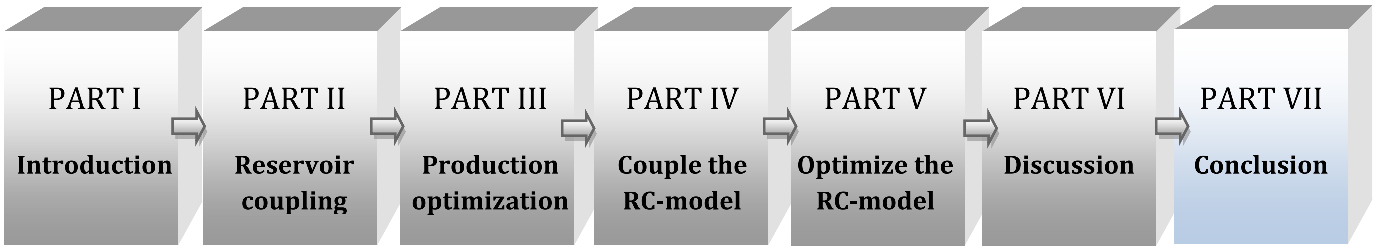
As seen in this chapter, there are some limitations related to the models used to build the RC model. The simulation results have indicated trends that have never been observed in reality, for example an increase in the liquid rate when Svale well G1 is shut.

Since the models used do not reflect the reservoirs entirely, the simulated results should be handled with care.

In order to minimize the mentioned uncertainties, future improvements related to the stand-alone simulation models should be done.

PART VII

CONCLUSION



In Part VII, Conclusion, the most important elements gained from this thesis will be stated.

This includes the advantages and disadvantages of using a RC model, the main results from the sensitivity analysis, the best method of choking the production on the Norne main field, and the simulation results from the RC-model.

7.1 THE MAIN CONCLUSIONS

The main focus in this thesis has been to optimize the hydrocarbon production of the Norne FPSO, within the available capacities of the existing facilities. For this purpose, a RC-model was build. Using this model has both advantages and disadvantages.

It makes it possible to dynamically calculate the THP pressures for reservoirs producing to the same flow line, prioritize the usage of the processing plants, between the fields that are using the same facilities, and make combined production plots.

The main drawback is that many Eclipse facilities, such as Prioritization and Gas lift Optimization, are not applicable to a RC-model.

The simulated hydrocarbon production on the Norne FPSO was optimized in two ways.

First, the production on Norne was choked. Both the use of Priority Rules and the use of Guide Rates have indicated that choking the wells with the highest water cut will lead to the highest recovery of oil.

Secondly, the simulation results have indicated that prioritizing the usage of the gas process plant, between fields that are using the same facilities, can give a higher gas production rate.

The results from the RC-model indicate that it is possible to constrain the water production on Norne, minimize the gas lift on Urd, and in the same time maintain the total oil production rate.

The main uncertainties regarding the simulation models used have been discussed.

First, the water cut gained from the Norne simulation model differs slightly from the water cut observed in the field. It is not believed that this difference has a huge influence on the simulation results.

Secondly, it is not believed that the effect of injecting one additional cubic gas into the Svale wells, in the Urd simulation model, is reflecting the reality in a good way. This may influence the simulation results.

Thirdly, the simulation results have indicated that closing a Svale well will lead to an increase in the liquid production. This positive effect of closing a well seems rather unlikely.

This has shown that it is important be critical to the results gained from a simulation model, and compare it to what is observed in the field.

Above all, this thesis has intended to show, that it is important to employ a good production strategy to optimize the hydrocarbon recovery.

NOMENCLATURE

A – User defined coefficient

B - User defined coefficient

C - User defined coefficient

D - User defined coefficient

E - User defined coefficient

F - User defined coefficient

FPSO – Floating Producing Storage Offloading

G- User defined coefficient

g - Gravity

GLIR – Gas Lift Injection Rate

GOPR – Group Oil Production Rate

GOR – Gas/Oil Rate

GPR – Gas Production Rate

GPT – Gas Production Potential

GR_{wat} – Guide Rate (water)

H - User defined coefficient

H - height

LPR – Liquid Production Rate

Nom. - Nominated

NPD – Norwegian Petroleum Directorate

OPP – Oil Potential Production

OPR – Oil Production Rate

OPT – Oil Production Total

OWR – Oil/Water Ratio

PDO – Plan for Development and Operation

POT - Oil Potential

Q_g – Gas Potential

Q_o – Oil Potential

Q_w - Water Potential

R_1 - Oil /Water Ratio, from potentials

R_2 – Gas/Oil Ratio, from potentials

RC – Reservoir Coupling

SM3 – Standard Cubic meter

THP – Tubing Head Pressure

WC – Water Cut

WOPP – Well Oil Potential Production

WPR – Water Production Rate

WPT – Water Production Total

ρ – Symbol for density

Units used

	Unit	Symbol
Giga	1000000000	G
Mega	1000000	M
Kilo	1000	K

REFERENCES

Adam, J. 1995. The Norne Field Development overview. Paper SPE 7925 presented at the Offshore Technology Conference, 1-4 May. DOI: 10.4043/7925-MS.

Eni Norge, http://www.eninorge.com/en/Field-development/Marulk/Facts/ . Downloaded 29 March 2012.

Geology.com http://geology.com/articles/haynesville-shale/haynesville-shale-well.jpg. Downloaded 29 May 2012.

Haavardson N. F., Huseby, A. B., Pedersen F. B., Lyngroth S., Xu J., Aasheim T. I., Det Norske Veritas. 2010. Hydrocarbon production optimization in fields with different ownerships and commerical interests. SPE Res Eval & Eng 13 (1): 95-104. SPE 10.2118/121399-PA

Kosmidis, V.D., Perkins, J.D., and Pistikopoulos, E. N. 2004. Optimization of well oil rate allocation in petroleum fields. Ind. Eng. Chem. Res., 43 (14): 3512-3527.

Ministry of Petroleum and Energy, http://www.regjeringen.no/nb/dep/oed/dok/regpubl/stmeld/2010-2011/meld-st-28-2010-2011/2/5.html?id=649721. Downloaded 13 February 2012.

Morell, E. 2010. History matching of the Norne field, Master Thesis, Norwegian University of Science and Technology, Trondheim, Norway.

Norwegian Petroleum Directorate, http://factpages.npd.no/factpages/Default.aspx?culture=no. Downloaded 17 April 2012.

Norwegian Petroleum Directorate, http://npdmap1.npd.no/website/npdgis/viewer.htm. Downloaded 3 February 2012.

Norwegian Petroleum Museum, http://www.norskolje.museum.no/stream_file.asp?iEntityId=733 . Downloaded 3 February 2012.

Schlumberger. 2011. Eclipse Technical Description, 395–406, 695-720, 825-848, 1226-1244: Schlumberger

Statoil, http://www.statoil.com/en/ouroperations/explorationprod/ncs/norne/pages/default.aspx . Downloaded 8 March 2012

Wang, P., Aziz, K. and Litvak, L. M. 2002. Optimization of production form mature fields. Non-SPE conference paper presented at the 17th World Petroleum Congress, Rio de Janeiro, Brazil, 1-5 September.

APPENDIX A
COMPARISON OF OIL PRODUCTION RATES

Appendix A consists of plots where the oil production rates from the stand-alone models are compared with the production rates form the RC-model.

Figure A 1 shows the comparison of oil production rate between the Alve stand-alone model and the RC-model.

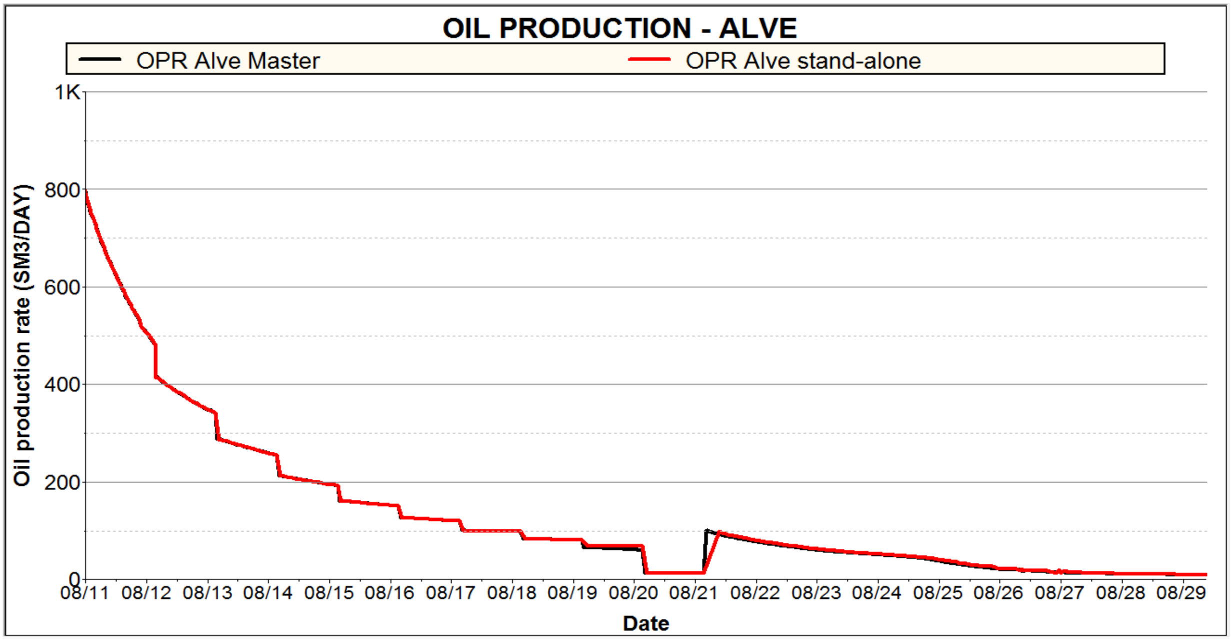


Figure A 1 - Comparison of oil production rate between the Alve stand-alone model and the RC-model

Figure A 2 shows the comparison of oil production rate between the Dompap stand-alone model and the RC-model.

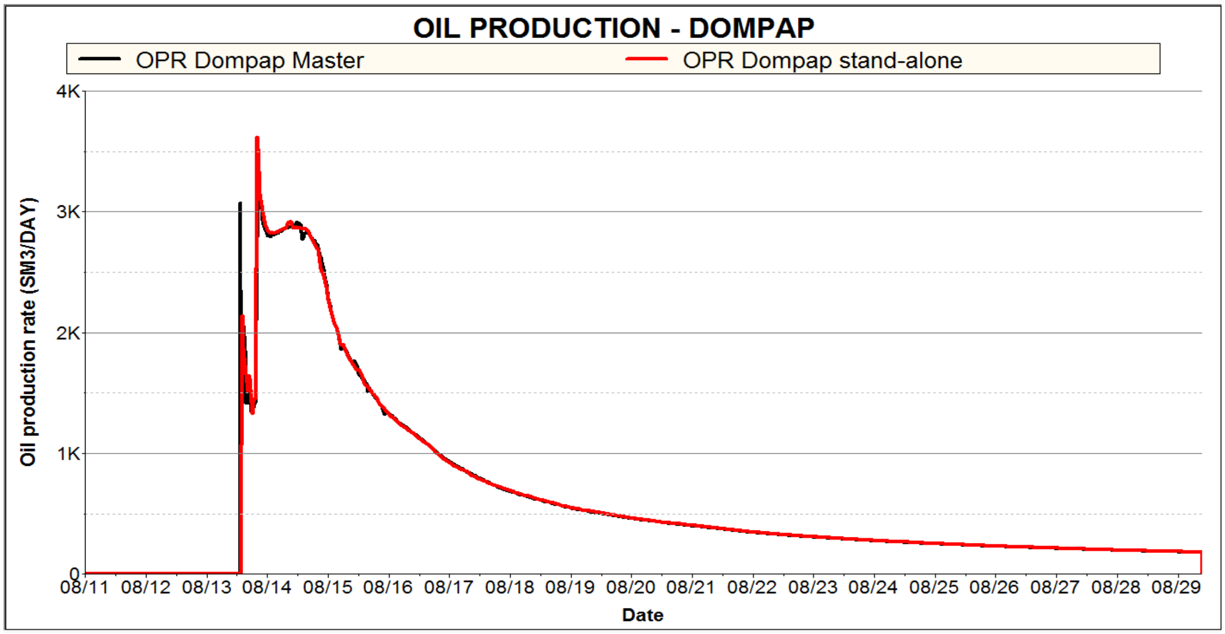


Figure A 2 - Comparison of oil production rate between the Dompap stand-alone model and the RC-model

Figure A 3shows the comparison of oil production rate between the Fossekall stand-alone model and the RC-model.

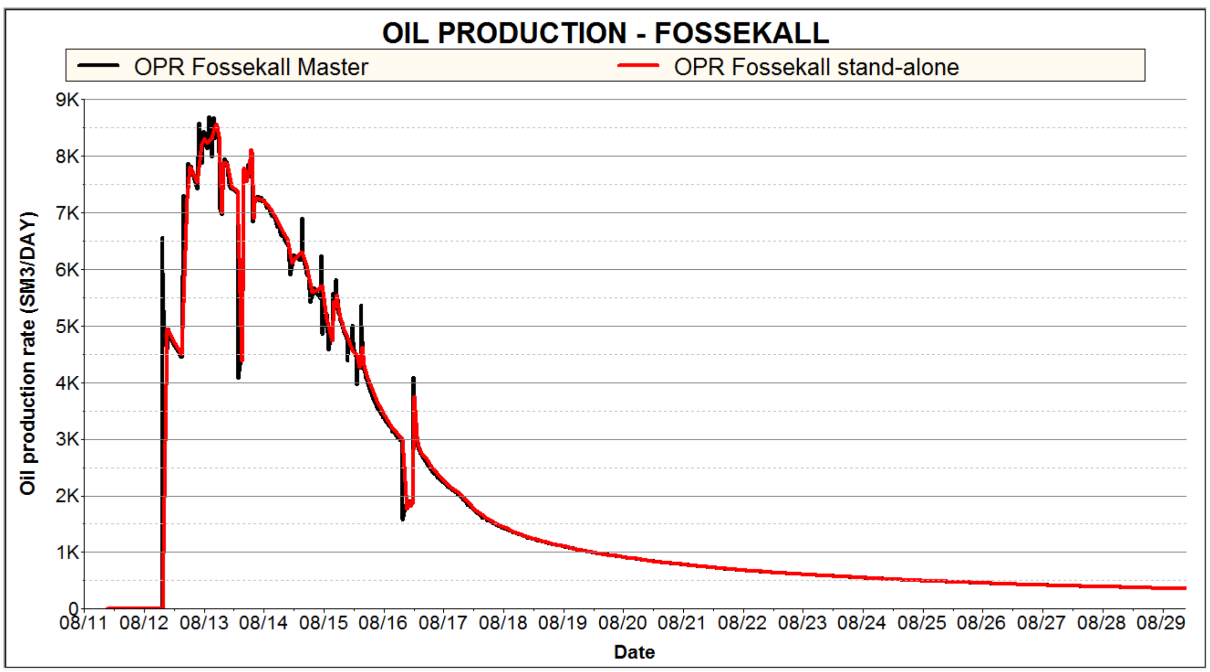


Figure A 3 - Comparison of oil production rate between the Fossekall stand-alone model and the RC-model

Note! The Marulk profiles are entered manually in the schedule section, in the master data file, and does not have a own stand-alone model.

APPENDIX B
CHOKING THE PRODUCTION – ECLIPSE METHODS

B.1 CHOKING THE WELL WITH THE HIGHEST WATER PRODUCTION RATE (WELL B1)

When well B1 is choked, the liquid outtake in the Tofte formation is reduced, and the pressure in the formation increases. This leads to an increased liquid production rate for the Ile-wells. The trend where the water production increases, while the oil production stays the same, can also be shown for group PM and PD2, see Figure A 4 - Figure A 7 .

Group PD2

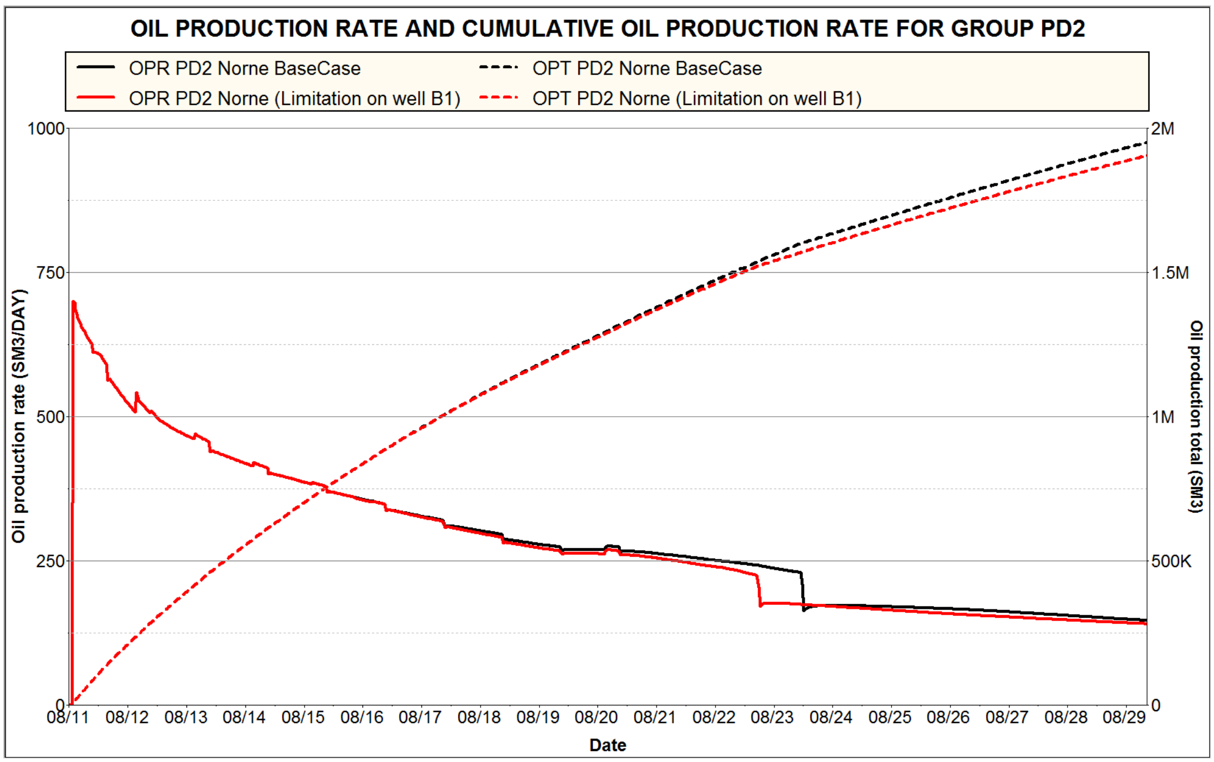


Figure A 4 - Oil production for group PD2 (Well B1 choked)

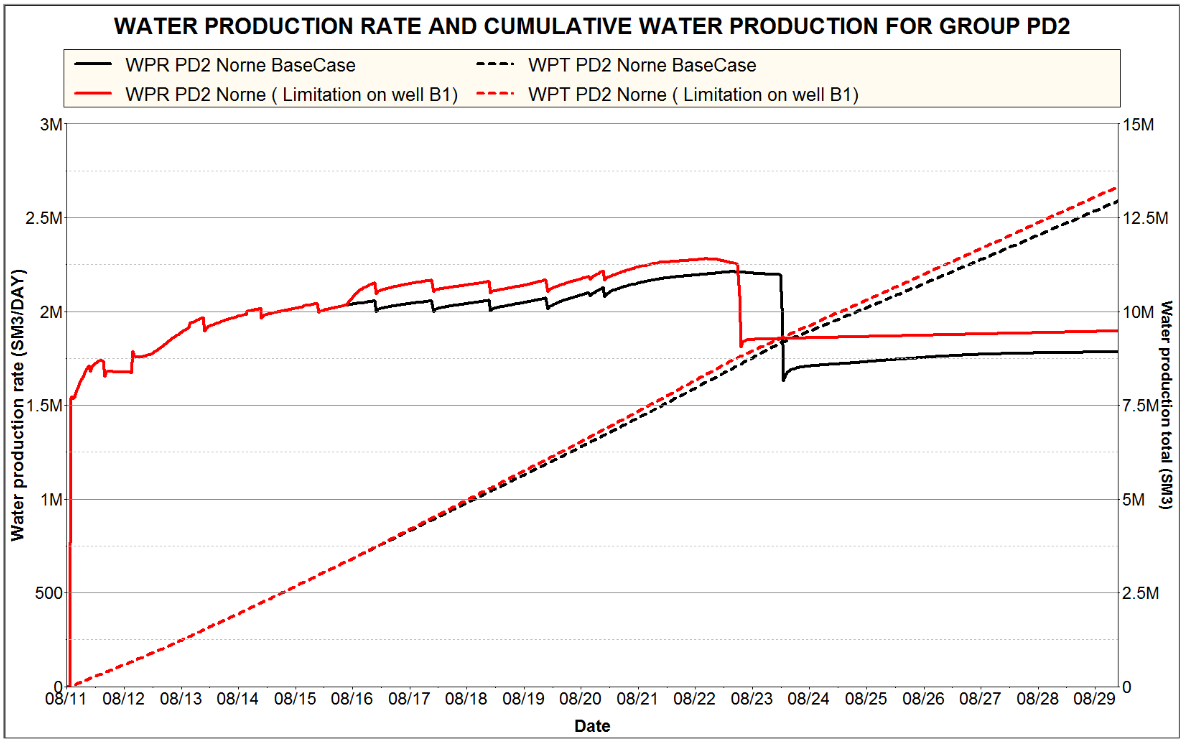


Figure A 5 - Water production for group PD2 (Well B1 choked)

Group PM

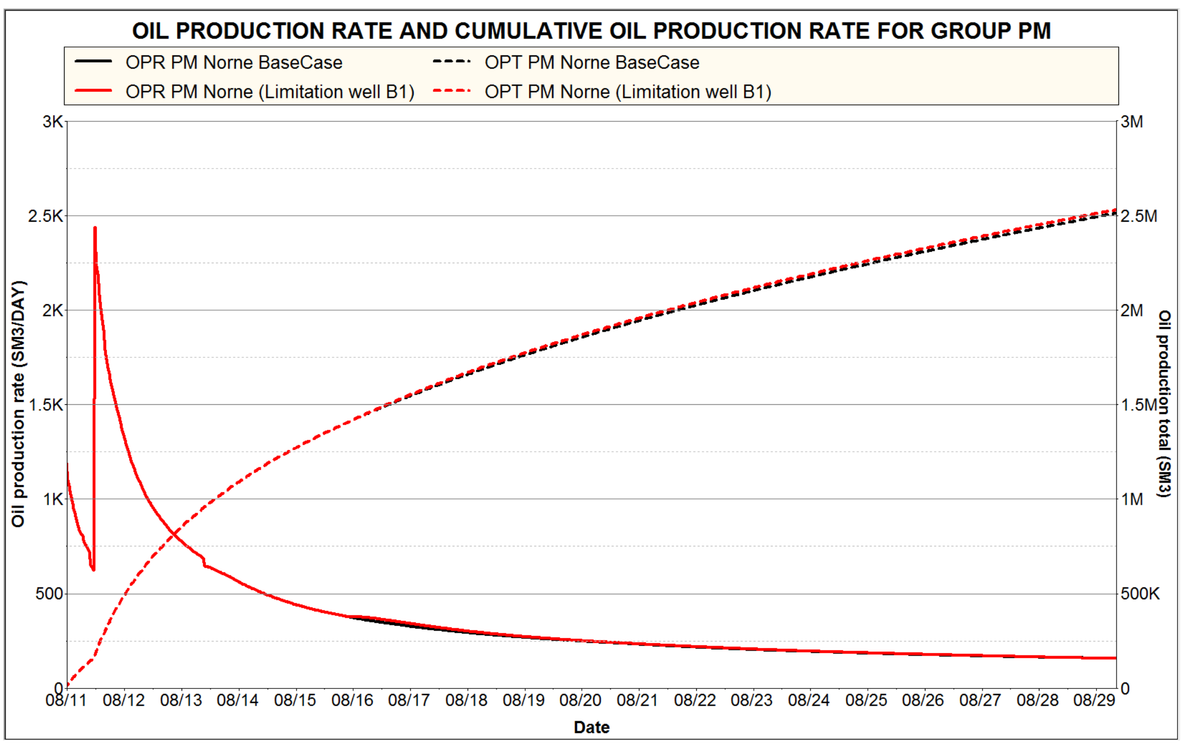


Figure A 6 - Oil production for group PM (Well B1 choked)

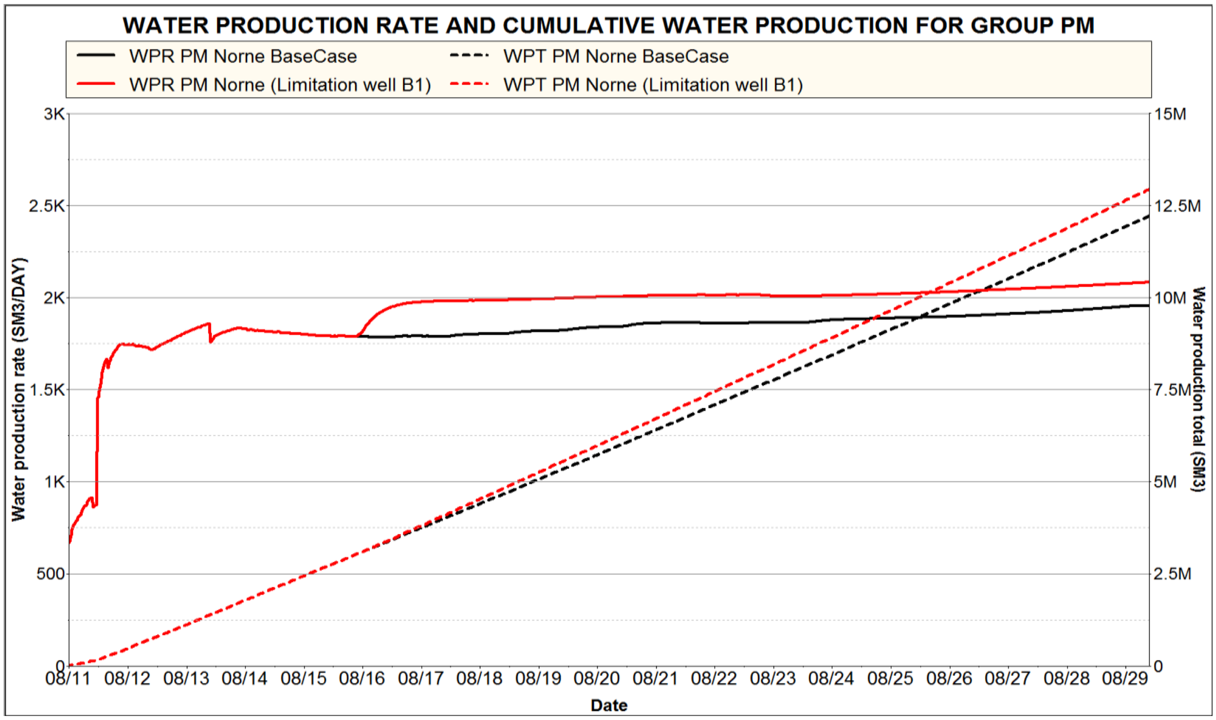


Figure A 7 - Water production for group PM (Well B1 choked)

B.2 CHOKING THE GROUPS PB1 AND PD2 USING THE FRACTION METHOD

The water production rate and the total water production for group PD2, that is given a water limitation of 2000 Sm3/day from the 1st of July, 2016 is shown in Figure A 8.

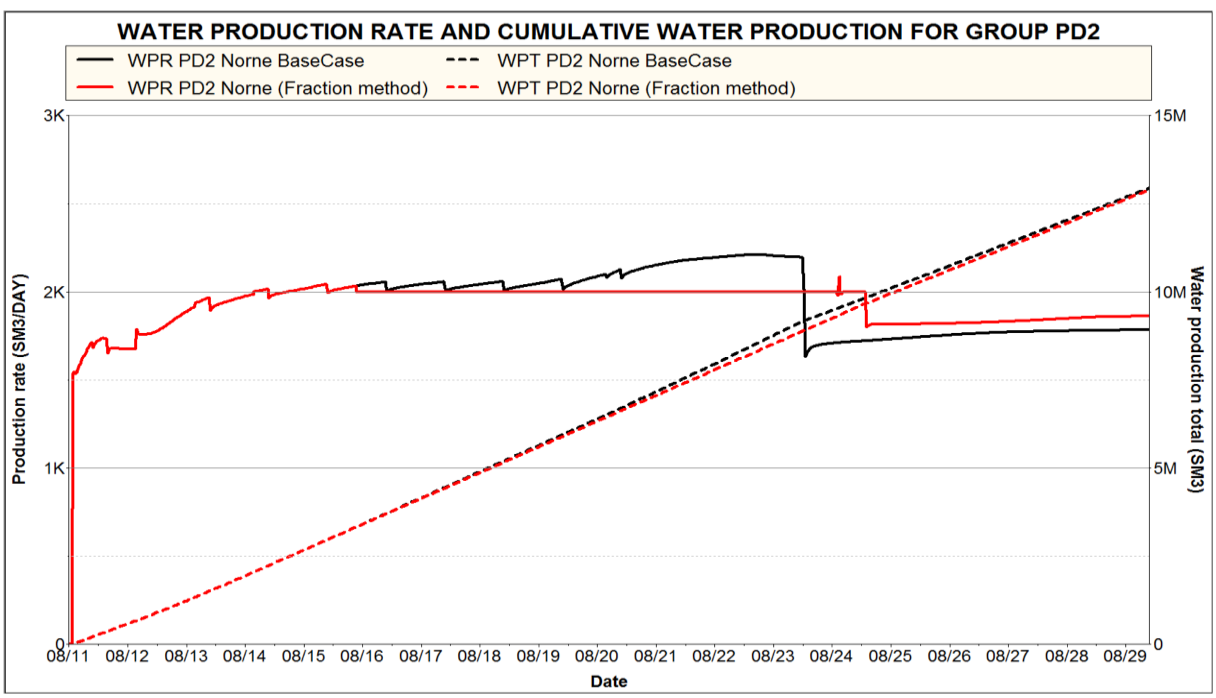


Figure A 8 -Water production rate for group PD2 (Fraction method)

The water production rate for each well in group PD2 is shown in Table A 1. Note that the fraction for each well is the came before and after the choking (blue numbers).

Table A 1 -Water production for the wells in group PD2 (Fraction method)

Well	Water production rate Before choking	Fraction	Water production rate After choking	Fraction
Tot.	2032		2000	
K2	1028	0.51	1029	0.51
K3	1003	0.49	971	0.49
D4	1	0.00	1	0.00

B. 3 Choke the production using Guide Rate on wells (Wells B1 and E3)

The wells in group PD2 are assigned water production rates, according to their Guide Rates, see Table A 2.

Table A 2 - Water production for the wells in group PD2 (Guide Rates Groups)

Wells	Guide Rate from formula	Fraction of total Guide Rate	Water rate [Sm3/day] After choking	Fraction of water production
Tot. prod.	552		1500	
K1	382	0,69	1037	0,69
K4	171	0,31	320	0,31
D4	0	0,00	0	0,00

APPENDIX C

TIME BETWEEN PRIORITY NUMBER CALCULATIONS

The priority option gives the user the opportunity to decide how often the well potential for each well is calculated. To see how the chosen number affects the cumulative oil production for å group, a sensitivity analysis is done. Three cases are studied, where the time interval between well priority calculations is:

- every time step
- every 100 days
- every 300 days

Every time step

How the different wells are choked back when the priority number is recalculated every time step, is shown in Figure A 9.

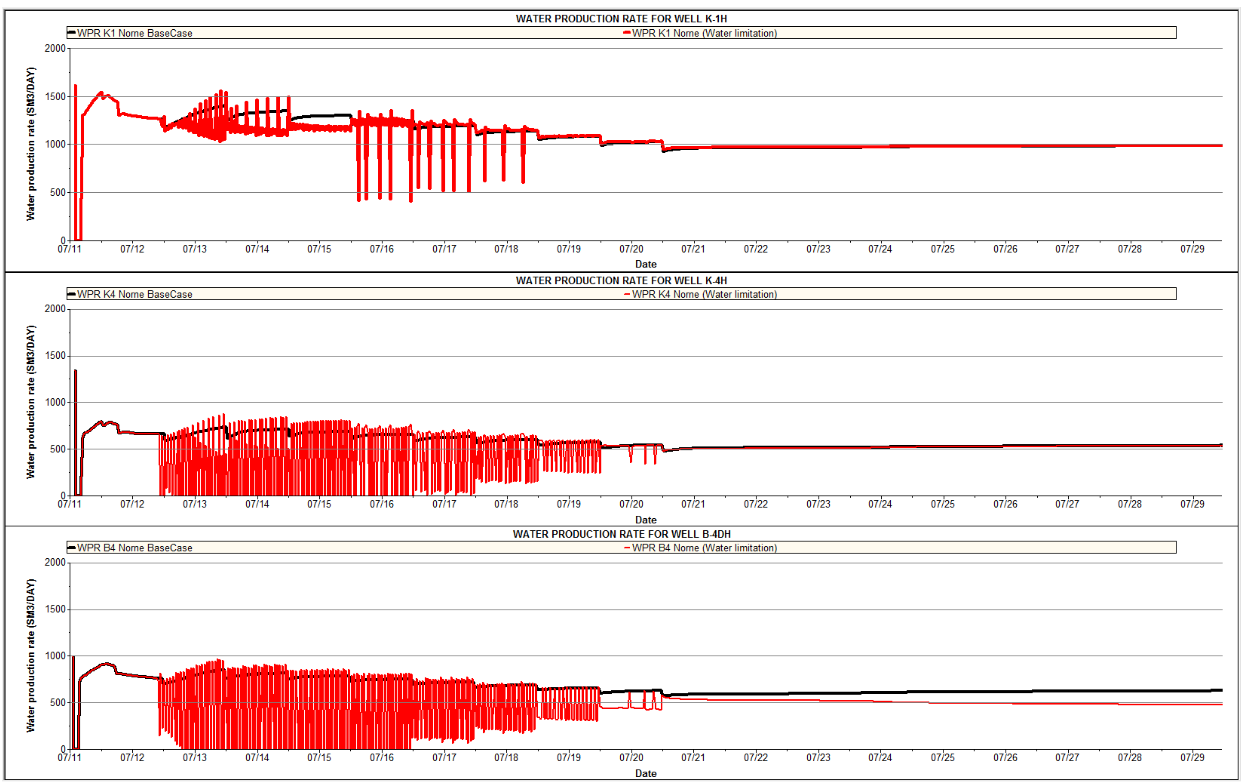


Figure A 9 - The water production for the wells in group PB1, priority number recalculated every time step

Since the oil potential are quite similar for two of the wells in the group, calculating the oil potential at every time step, leads to oscillations with some wells switching on and off.

Every 100 days

How the different wells are choked back when the priority number is recalculated every 100 days, is shown in Figure A 10.

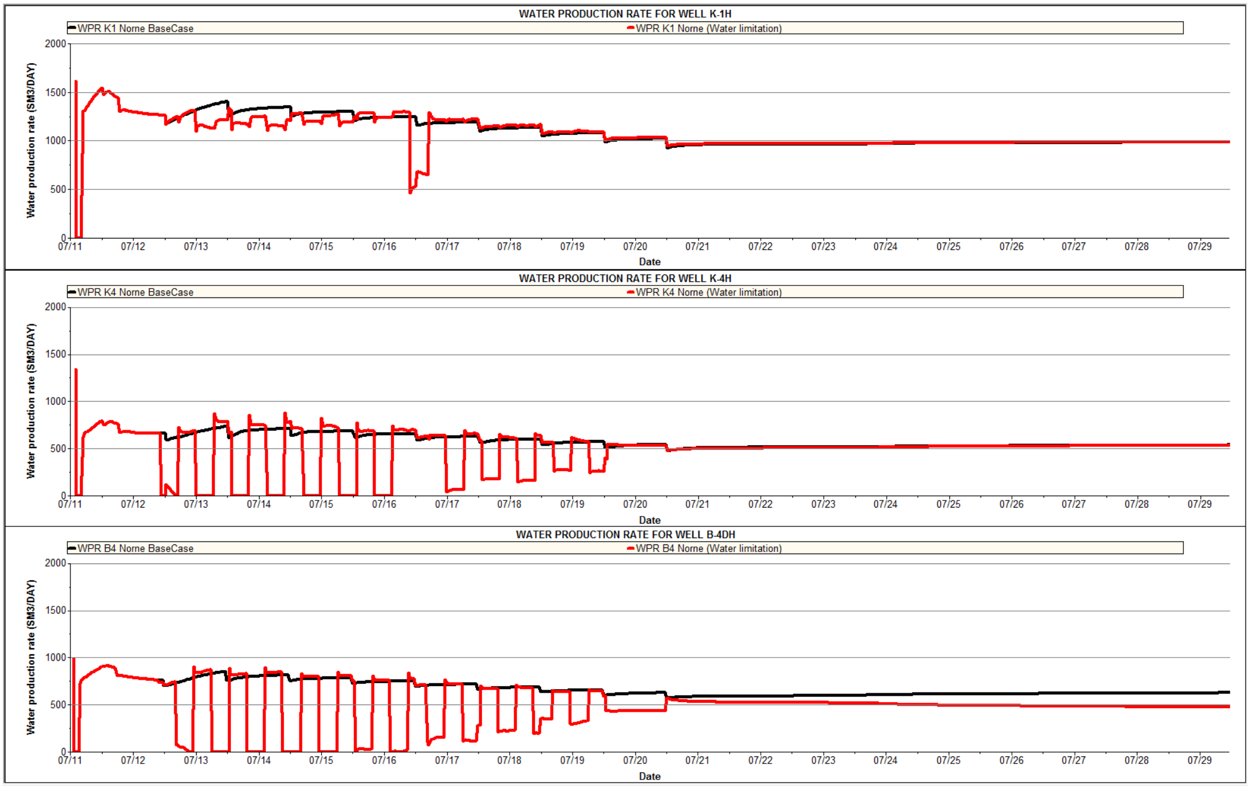


Figure A 10 - The water production for the wells in group PB1, priority number recalculated every 100 days

Every time the oil potential is recalculated, a new well is choked back. The explanation could be that the oil potentials are quite equal.

Every 300 days

How the different wells are choked back when the oil potential is recalculated every 300 days, is shown in Figure A 11.

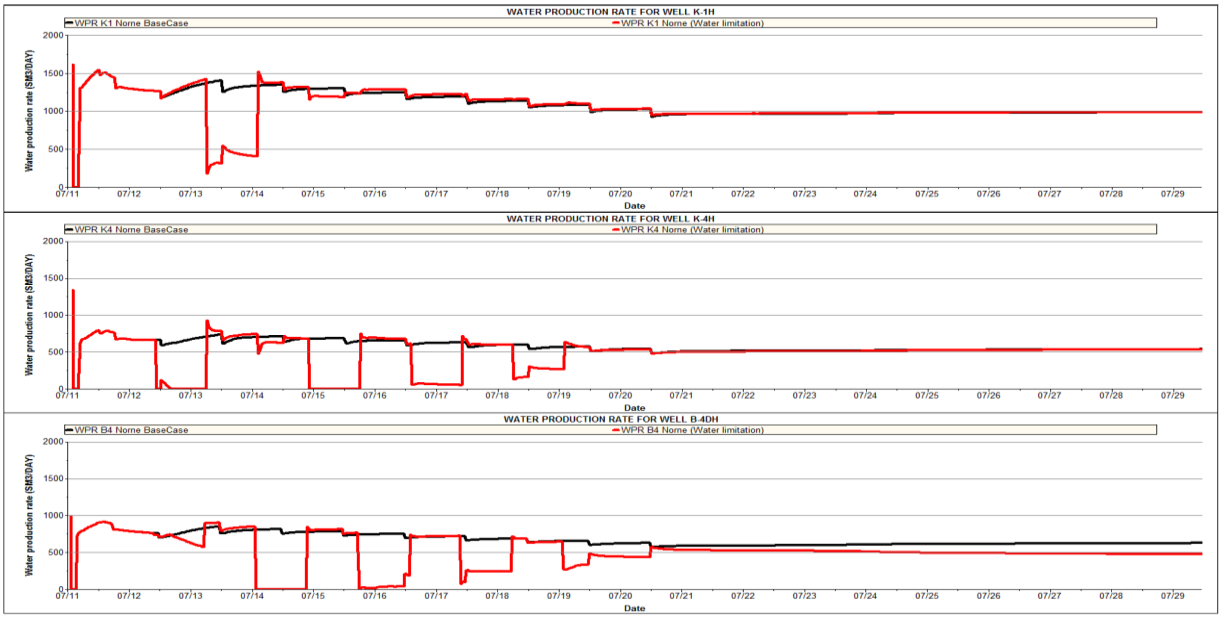


Figure A 11 -The water production for the wells in group PB1, priority number recalculated every 300 days

How the chosen number affects the cumulative oil production for the group, is shown in Figure A 12.

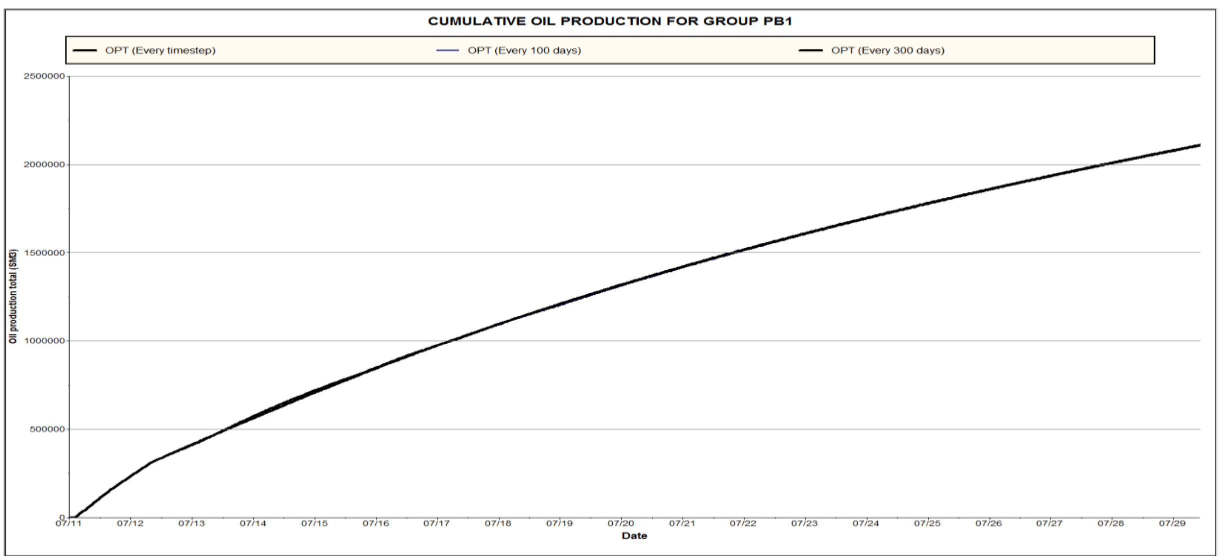


Figure A 12 - The cumulative oil production for group PB1 (Change in time between the priority calculations)

In this case, the total production of oil is the same, regardless if the user calculates the oil potential at every time step, or every 300 days. The only thing that changes is which wells that are producing at a given time.

APPENDIX D

ACTIONX ROUTINE

This Appendix shows the script used in the Eclipse data file, in the Urd Slave in the Coupled model, to minimize the gas lift on Urd in the Coupled model. This example shows how it is done for the Svale well G1 in 2012. This routine was also applied to the wells G2 and G4 and routine was repeated in September each year.

```
DATES
1 'SEP' 2012 /
/


ACTIONX
ACT10 1 /
WMCTL 'G-1H' > 0 /
/

WCONPROD
    'G-1H'      'OPEN'      'GRUP'  5000.000  2*   6000.000  1*     50.000     30.000    5 50000.000  5* /
 /
ENDACTIO


DATES
3 'SEP' 2012 /
/

ACTIONX
ACT13 1/
WMCTL 'G-1H' = 0 /
/
WCONPROD
    'G-1H'      'OPEN'      'GRUP'  5000.000  2*   6000.000  1*     50.000     30.000    5 60000.000  5* /
 /
ENDACTIO


DATES
5 'SEP' 2012 /
/

ACTIONX
ACT16 1 /
WMCTL 'G-1H' = 0 /
/
WCONPROD
    'G-1H'      'OPEN'      'GRUP'  5000.000  2*   6000.000  1*     50.000     30.000    5 100000.000  5* /
 /
ENDACTIO
```