Chair of Petroleum and Geothermal Energy Recovery

Master Thesis

Well Level Production Loss Management in a Digital Oilfield Environment

Written by:
Dragoș Ionuț Chețan, BSc
M1435705

University advisors:
Univ.-Prof. Dipl.-Ing. Dr.mont. Herbert Hofstätter
Dipl.-Ing. Abbas Zamani

Company advisors:
Mr. Philipp Tippel, Head of Production Operations
Mr. Mohammad Rostami,Technical Advisor & Project Manager

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Danksagung / Acknowledgement

I would like to thank my university supervisor, Mr. Abbas Zamani for his continued support and guidance in writing my thesis.

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Last but not least, I would like to thank my family, because I would not have reached this point in my academic life without their love and support.

"If people begin with certainties they shall end with doubts. But if they are content to begin with doubts they shall end in certainty."

Sir Francis Bacon (1561-1626)

Kurzfassung

OMV Petrom, mit einer aktiven Őllquelle Lager von 8,000 Őllquellen, erlebt häufig Öl- und Gasproduktionsverluste von seinen produzierenden Quellen aus Gründen wie elektrische Unterbrechungen, extremen Wetterbedingungen , Betriebsstörungen , usw. Die Ergebnisse sind ungeplanten Produktions Zurückstellungen, erhöhten Kosten und Gesundheit & Sicherheit Belastung des Personals aufgrund der Notwendigkeit manueller Eingriffe bei den Őllquellen Standort. Zurzeit durchführt OMV Petrom mehrere Pilotprojekte im Rahmen der Digital-Ölfeld –Programm, die die Produktionsverluste über fernbediente Operationen am Őllquellen reduziern soll.

Der erste Teil der Arbeit wird die wichtigsten Konzepte eines digitalen Őllfeld einführen und wird die Industrie Forschung der angewandten DOF / IO Ansätze auf Produktionsverluste Management über den fernbedienten Operationen am Gas- und Őllquellen präsentieren.

Produktionsverluste von OMV Petrom werden zu Herstellungssektorebene und Unternehmensebene durch den Verlust Kategorie zusammengefasst (z.B. elektrische Unterbrechungen, schwache Quellen, Oberflächenarbeiten usw.). Nachdem wir jede einzelne Kategorie verstehen, werden wir Verlust Kategorien gemäβ dem Quellen Niveau den durch einen DOF Umfeld verbebessert werden können indentifizieren.

Die Auswirkungen der wichtigsten Produktionsverlust Kategorien, zum Beispiel elektrische Unterbrechungen, wird untersucht und festgestellt, und Abhängigkeiten mit anderen Kategorien wie Ausfallrate der künstlichen Aufzugsanlagen werden korreliert. Zum Beispiel Quellen anfällig für Sandproduktion könnten ein Produktionsverlust Fokusgruppe mit primären Kategorie "elektrische Bremse" und sekundären Kategorie "Pumpenausfall " sein.

Die Reduzierung der Produktionsverluste wird für ausgewählte Kategorien geschätzt durch die Nutzung von DOF Ansätze und Methoden zur Implementierung werden präsentiert.

Laufende Produktionsverlust Management-Ideen und Initiativen in OMV Petrom, E & P werden erfasst und in einem Portfolio zusammengefasst und verglichen zur besten Vorgehensweise der Branche. Es ist empfohlen die besten Methoden zu verwenden.

Ein Vorschlag für die Durchführung der Echtzeitüberwachung über den Operations Hub (Kontrollraum) wird präsentiert, zusammen mit einer Reihe von Empfehlungen für ihren Einsatz.

Um einen Eintrag zur Schlussfolgerung zu machen, wird eine Reihe von KPIs (Key Performance Indicators) für Űberwachung definiert, die den Wert/ Vorteil generiert durch die Implementierung von DOF Methoden für die Produktion Verlustmanagement zeigen.

Abstract

OMV Petrom, with an active well stock of more than 8,000 wells, frequently experiences unplanned oil & gas production losses on its producing wells for reasons such as electrical breaks, harsh weather conditions, equipment failure, etc. The results are unplanned production deferments, increased costs and health & safety exposure of personnel due to the necessity of manual interventions at well sites. OMV Petrom is currently running multiple pilot projects as part of its Digital Oilfield program, aimed at reducing production losses via remote well operations management.

The first part of the thesis introduces the main concepts of a digital oilfield and presents industry research of applied DOF/IO approaches on production loss management via remote operations related to oil & gas wells.

Production losses of OMV Petrom are summarized at production sector level and company level by loss category (e.g. electrical breaks, weak wells, surface works etc.). Following an understanding of each category, loss categories on well level that can be improved via a DOF environment are identified.

The impact of main production loss categories, e.g. electrical breaks, is investigated and concluded, and dependencies with other categories such as failure rate of artificial lift equipment are correlated. For example, wells prone to sand production could be a production loss focus group with primary category “electrical breaks” and secondary “pump failure”.

The reduction in production losses is estimated for selected categories by using a DOF approach and methods for implementation are presented.

Ongoing production loss management ideas and initiatives in OMV Petrom, E&P, are captured and summarized in a portfolio map and compared against industry best practices. Best methods to be used are recommended.

A proposal for the implementation of real-time monitoring via operational hub (control room) is presented, along with a set of recommendations for its deployment.

To conclude, a set of KPIs (key performance indicators) to be monitored is defined, showing the value/benefit generated by implementing DOF methods for production loss management.

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Abbreviations

DOF	Digital Oilfield
IO	Integrated operations
E&P	Exploration & Production
KPI	Key performance indicator
ESP	Electrical Submersible Pump
PI	Productivity Index
Bln	Billions
To	Tonne
bbl	Barrel
IPSM	Integrated Production System Modelling
DACA	Data Acquisition and Control Architecture
SPD	Salym Petroleum Development
SCADA	Supervisory Control and Data Acquisition
XSPOC	Comprehensive well management system
FW ESP	FieldWare Electrical Submersible Pump
EOR	Enhanced Oil Recovery
HSSE	Health, Safety, Security and Environmental
PIMMS	Production Information Management and Monitoring System
PCP	Progressive Cavity Pump
SAM	
MTBF	Mean Time Between Failure
HPHT	High Pressure High Temperature
WAP	Well Automation Program
OPEX	Operational Expenditures
WA(P)	Well Automation (Program)
AL	Artificial Lift
A1 – 9	Asset 1 – 9
RPC	Rod Pump Controller
SRP	Sucker Rod Pump
LRP	Linear Rod Pump
BPM	Bussiness Process Management
SaaS	Software as a Service
CAPEX	Capital Expenditures
NPV	Net Present Value
IRR	Internal Rate of Return
NIR	Near-infrared
GHG	Greenhouse gas
PTP	Phase to Phase
PTG	Phase to Ground
HV/MV	High Volt/Medium Volt
RTU	Remote Terminal Unit
V.A.D.	Value Adding Decision
MM	Million

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1 Introduction

The oil industry has always been affected by cyclic changes due to oil price fluctuations. Figure 1 clearly illustrates the steep decline as for Brent crude oil price over the last 3 years. The decline started mid-2014, from around a constant $110 a barrel to around $39 at present time (April 2016). In times when the price is low, such as what is experienced currently, it is highly important to manage costs and increase efficiency.

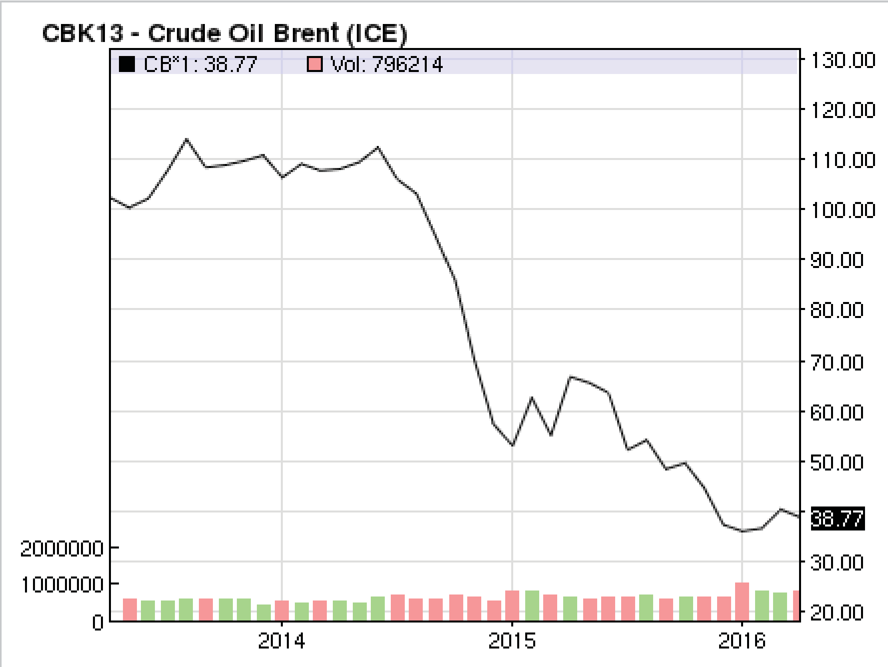

Figure 1: Brent Oil Price over the last 3 years [1]

Over the last twenty years, technology has developed successfully to allow new performance breakthroughs. Unit costs have decreased by almost two thirds in the E&P sector, technology being responsible for 80% of the decrease [2]. New techniques or equipment are part of the technology, for example 3D/4D seismic, horizontal and multilateral wells, and subsurface geological modelling.

At a well production level another type of technology has also contributed: computer processing power and information technology. Progress has been achieved with data acquisition (telemetry, sensors, storage and analysis) and control which allowed a better operation of the wells, reduced production losses and better reservoir management.

Technology is nonetheless dependent on people, so there is a need for skilled individuals to handle these new processes and equipment. Automating a system generates a lower level of workforce needed for the tasks that were previously done manually, but a higher level of staff training needed in order to have an integrated system where value is added by proactive use of technology. An example is real-time monitoring of a well, which can highlight suboptimum use of the pumping equipment, and can prevent equipment failure by taking early action.

2 Literature review

2.1 Digital oilfields

Overview

A digital oilfield has the purpose to increase recovery, reduce non-productive time, and rise cost-effectiveness by adopting integrated workflows. These workflows are used to streamline and automate activities done by cross-functional teams by combining business process management with cutting-edge information technology and engineering know-how.

A large diversity of activities are referred to by the term “digital oilfield” and a large diversity of tools, activities, and disciplines were incorporated by its definitions. All of the definitions try to describe the various uses of cutting-edge software and data analysis procedures to increase cost-effectiveness of petroleum production processes. Regular digital oilfield topics consist of, but are not limited to:

- Operational efficiency
- Production optimisation
- Collaboration
- Decision support
- Data integration
- Workflow automation

The current challenges encountered by the petroleum industry are unparalleled and help in understanding the growth of digital oilfield technology. Here are a few examples:

- Staff age distribution (“crew change”)
- Increase in software applications and data formats
- Global working environments
- Flood of real-time data with immediate availability
- New discoveries and their size decreasing
- Rising cost of cutting-edge recovery technologies

By combing the digital oilfield topics with the challenges stated above it can be concluded that digital oilfields are implemented to pay off for a greater complexity and cost of activities, which must be done by a smaller number of less experienced staff. The role of digital oilfields in achieving that is to incorporate and speed up several of the jobs and procedures usually done by engineers, geoscientists, field specialists, financial specialists, and even managers. Methodical and associated groups of such jobs are referred to as workflows, and industry experts focus more and more on workflow design.

Industrial engineers or operations management specialists are responsible for the design of workflows and processes. The petroleum industry is adapting to the new way of organisation by integrating traditional divisions of responsibilities among functional lines (e.g. reservoir, completion, and production engineers) into engineering workflows and business processes that more accurately mirror the company goals to be reached (e.g. reservoir surveillance, well test validation, production optimisation). One way to describe digital oilfields is a combination of workflows that allow fast, collaborative execution of interconnected activities in dispersed (virtual) teams, with an end result that is efficient and more lucrative.

History

The first initiatives of adopting a digital oilfield started around the turn of the century and have developed into the software, data technology and engineering innovations that are used today. However, the first type of workflow was implemented in 1976 and used for the integrated modelling of flow through a pressure-connected system of reservoirs, wells, and surface production facilities.

Publications of case studies using this workflow appeared under the names “tightly couples reservoir-wellbore-surface network simulations”, “integrated production models” or “integrated asset models” and started to raise awareness of the advantages of collaboration and of workflows that crossed functional lines. Engineers employed in diverse domains could predict the possible effects of their decisions on the other points of the production network (E.g. just by running a workflow, a production engineer could see that there is not enough separation capacity at the facilities to handle an increased well flow rate).

One more initial advantage of integrated asset modelling was that it considered the uncertainty of model inputs by generating probability distributions of outputs, along with their expected values. The capability to automate the implementation of different scenarios was directly understood as a main advantage of integrated asset modelling, helping today in developing new workflows.

Digital oilfield operations started to actively optimize desired results within a given set of restraints, rather than just deliver distributions of scenario outcomes. This was possible because the development of workflow designs, the level of understanding of digital oilfield users, and the accessibility of computing power all improved. Thus, there was a drive to get workflow outcomes quicker in order to take full advantage of the potential cost savings, and digital oilfields started to help in decision support.

Most of the times, the interval needed to execute engineering models was not the factor postponing decision support from workflows. It was the excessive time spent by engineers to find, organize, process, enter, and validate data, prior to any investigation being possible. As a result, digital oilfields also had to solve the data management issues. Discussions emerged about “technology integration” together with workflow integration and model integration. Data coming from a varied range of sources, ranging from legacy software file formats, relational databases, email, to PDF, and so on had to be loaded, stored, cleaned, processed, and validated by the implementation of data sources. All this data independent of its origins had to be easily available for usage in any workflow.

Moreover, companies had to begin learning to use these systems successfully, and change management required the development of business process management tools (BPM). BPM gave companies the capability to carry out best practices, first through the design of workflows by subject focus experts, and then through the succeeding implementation of the workflows by all staff in combination with a system of flowchart-based process diagrams, automatic email reports, and obligatory review-and-approve steps. Consequently, BPM is vital in any digital oilfield deployment.

The design of digital oilfield systems was also affected by the increasing impact of the Internet. A bigger standardization of company systems across assets and regions was sought after as companies became more confident in using digital oilfields. A common visualisation of models and data web-based visualisation environments were implemented to decrease information technology costs and to allow collaboration of widely spread teams. The “Software as a Service” (SaaS) was a concept that allowed digital oilfield providers to bring exactly the functionality wanted by a client, in a way that was simple for information technology administrators to set up globally, whatever the scale.

Upcoming tendencies

In the last 10 years there was a great progress in the design, deployment, and usage of digital oilfields. Today, after numerous lessons taught by the past, the highest difficulties are considering the people involved in the process: management of change, staff ability development, business processes design, and making people understand the extra value to be added.

Nowadays, the main technological features needed to deploy a modern digital oilfield are normally accessible, and the fast and growing pace of technology change features unique challenges and opportunities. For example, if in the past providing instrumentation to wells and facilities to get practical production data was a challenge, now the challenge is to build workflows for simulation and optimisation that can make use of the huge amount of received data, clean it, process it, execute models, analyse them, and provide real time recommendations to the people with decision power. Engineers can now forecast system performance, an option not available or very time intensive in classic physics-based models. This is possible due to the “data revolution” which makes it possible to build several new types of models, data-driven or “proxy” models.

Closed-loop control of operating facilities is a practice that is extensive in most industrial environments, and even in the downstream sector of the petroleum industry. It is an additional scope which is expected to be encompassed by digital oilfields in the future. The industry transformation will be done with a clear attention to health, safety, and the environment by the operators who lead it. Accordingly, operational efficiency and the optimisation of processes that are not directly connected to the primary petroleum engineering activities will become focuses of the digital oilfield.

The digital oilfields develop both horizontally to include each part of operations and engineering and vertically in the business to cover each profession, from accounting and finance, to executive management. This will lead to digital oilfields becoming digital companies, and all the information related to the acquirement, development, production, and disposition of oil & gas assets will be managed at the headquarters with BPM procedures, coordinated workflows, and reports. If an asset suffers a change in production plan, the gradually more refined workflows that contain financial analysis will output a revised portfolio optimisation plan kept by the Finance Department, and the deviations in Net Present Value will be made instantaneously accessible to executive decision-makers.

Digital companies will introduce a situation in which each discrete technical decision is clearly visible to every stakeholder. Objective functions used to optimize technical operations will be influenced by the company's financial situation. By then, digital oilfields will resemble the most cutting-edge factory processes: economic, streamlined, and effective. [3]

2.2 Production automation and remote monitoring

Production automation systems have been present in the petroleum industry for a long period of time. In the 1960s they were used mainly to monitor production parameters like pressure, temperature and flow rate, having few remote control options (e.g. pump start/stop, remote facility shutdown, automatic well testing). The term supervisory control and data acquisition (SCADA) was established to define the system. The evolution remained slow-paced due to numerous issues with the equipment, communication, computer hardware and software, small scale exposure to production operations, and difficulty in understanding and accepting this new technology by the people.

Nevertheless, progress has been dramatic over the last few years. Nowadays, improved production management and optimisation is possible with the use of oilfield automation. The entire production system can be optimised, starting with the reservoirs, the wells, the gathering lines, testing, treating, handling facilities, to the final sale points. The accuracy and price of the equipment, communications, and computer hardware and software have improved, and people are beginning to understand and accept the benefits of using this technology to enhance the oil and gas business.

However, there is a mixed state of the art of production automation systems across the globe. Most of the times, the deployment of automation systems and information technologies (communications equipment, measurement and control devices, databases, and computer hardware and software) is more advanced than the ability to successfully understand and apply this technology. This low approval and support is caused by scarce training and staff improvement programmes. A strategy must exist for the individuals who have the needed understanding, expertise and motivation to be developed and engaged. The provision of support and training systems must be enhanced by both producers and contractors for the technology to gain its full potential.

In times of stretched workforce and limited resources, the business circumstance for spreading over this technology is very convincing. Automation and information management can improve cost-effectiveness of petroleum production processes by leveraging limited resources. The areas where it can help are in optimising investments, production levels, repair and maintenance, and operating costs. Additionally, it can offer prospects for staff development and aid in reducing health, safety, and environmental events.

3 Industry research of applied DOF/IO approaches on production loss management via remote operations related to oil & gas wells

With millions of dollars being invested in a pursue to increase efficiency and reduce production losses, digital oilfields are an important focus for oil companies. Solutions have been developed for data communication from the field to office in real time. What is done with the data after it has been recorded is highly important, because just monitoring the status of the wells and equipment doesn't bring the full potential of this technology.

The solution is to use the data in optimizing the production system on a well and reservoir level, by extracting the relevant data at the right time. In order to create value, the information recorded must be analysed and solutions must be applied in a well-timed manner.

The three foundations of implementing a digital oilfield are People, Processes and Technology. The current status of technology in measuring, transmitting and monitoring the data is very developed. The problematic pieces of the puzzle are the other two groups, with a shortage in trained people and processes to integrate the data in production optimization workflows.

Decisions may take hours in an operations environment, days in a production environment and months in reservoir management. There is a need for semi-automated optimization workflows to allow decisions to be taken at different levels. The goal of real-time monitoring is to decrease the number of staff needed per well and thus increase efficiency, to lower the costs by fewer trips to the well, and reduce well downtime by preventive measures.

Well level production losses optimization refers to bringing the production as close as possible to its potential by controlling the inflow and outflow characteristics using the real-time captured data.

Field level optimization can be done in two ways: single process optimization and whole asset optimization. In single process optimization only one element of the field is improved, for example the ESP system in the whole field. In whole asset optimization, multiple elements of the field are improved (individual lift systems, water injection, well and reservoir deliverability). [4]

3.1 Aethon Energy and Schlumberger

"Aethon Energy is a private investment firm with a focus on direct investments in North American onshore oil & gas assets. Since its inception in 1990, Aethon has maintained a focus on acquiring underappreciated assets, where opportunities exist to add value through lower risk development, operational enhancements, and Aethon's proprietary technical knowledge. Aethon's 25-year track record spans multiple energy cycles and has consistently provided compelling returns through disciplined buying and value creation." [5]

Following is a research of the operations of Aethon Energy in a consortium with Schlumberger, using the three pillars of a digital oilfield (technology, processes, and people) to improve productivity in one of their fields.

The technology used to measure and transfer data from the wellsite to the office facilitates the real-time optimization system. State of the art technology was used in the project described below, with standards that can be adapted from a small scale such as a single well to a wide scale such as a field.

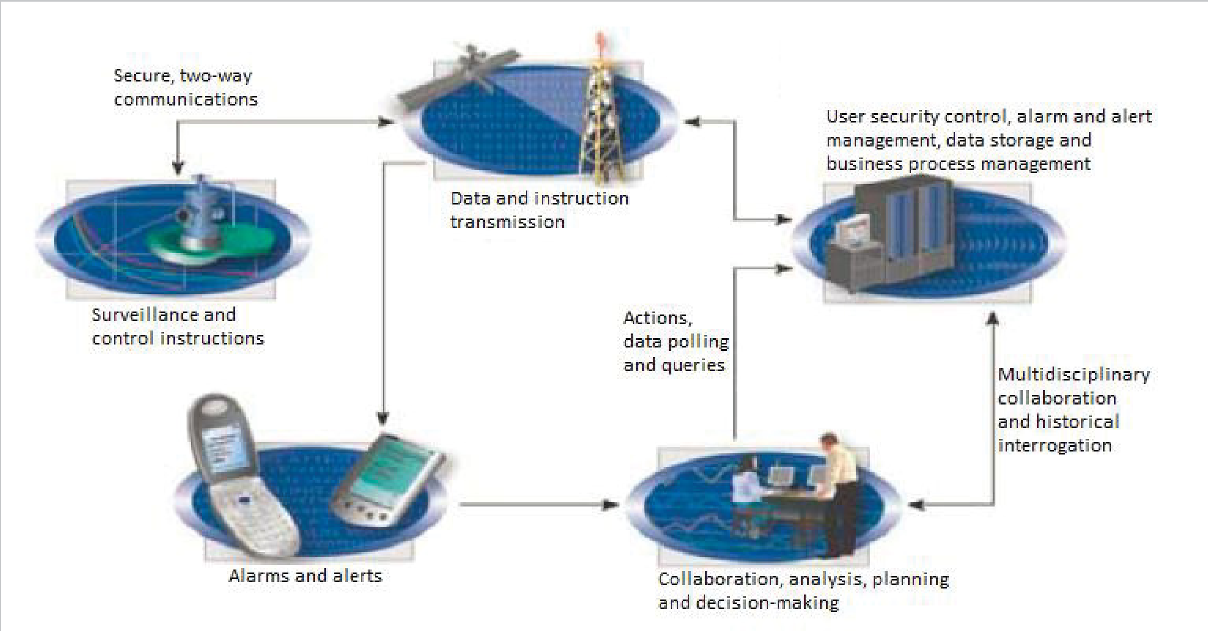

Figure 2: Real time optimization infrastructure system [4, p. 2]

In Figure 2 data flow interactions can be tracked. This system can be applied for a field with any type of artificial lift, even though the one presented uses ESP.

The ESP systems had downhole sensors installed, which measured bottomhole pressure and temperature. Other key pump parameters such as motor temperature, vibrations, etc. were measured and linked to reservoir performance. Data transmission was done by telecommunication (satellite) to a command center with full time support.

The frequency of the transmission to the center depends on the status of the well. A well which is stable in terms of productions sends the data daily, in order to generate trends and to save costs. A web interface is used to change the transmission frequency. If the recorded information is outside a certain threshold, it is automatically transmitted and the control center is notified.

Technology is at the base of the digital oilfield and it enables a centralized infrastructure. It does this by providing services such as a two way data communication, data storage, alarms and event management, messaging and real-time computations. Workflows are developed based on this infrastructure. A standard workflow of the monitoring system is presented below, in Figure 3. Output data can be seen by all stakeholders using web accessible pages.

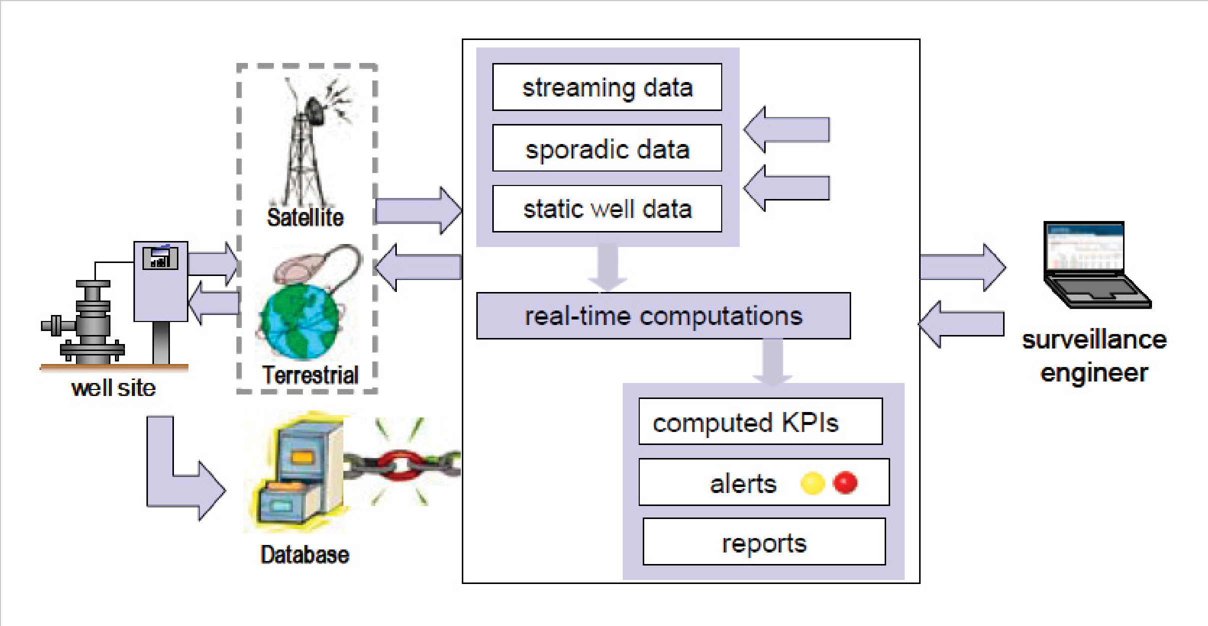

Figure 3: Standard workflow of the monitoring system [4, p. 2]

The monitoring and optimization processes of a well contain automated online monitoring workflows and off-line diagnostic workflows.

The automated workflows allow the monitoring of multiple wells by a practical identification of the problems. This is usually done with alarm systems that generate notifications on specific events. Deviations from normal operating conditions are analyzed by web-based tools, by tracking the parameters and their trend.

Off-line diagnostic workflows consist of well, pump and reservoir performance analysis, the latter being done considering the transient pressure.

Monitoring workflows

By using automated monitoring workflows the deviations from normal operating conditions can be quickly caught, preventing equipment failure and reducing field visits. Cost and efficiency are improved, one person being able to monitor many wells.

Automatic monitoring has two basic elements: setting thresholds for generating an alarm and reaction to the alarm. Threshold generated alarm are activated when the wellsite streaming data becomes deviated from normal operating conditions data. Notifications can be sent by phone, pager, email or fax to the responsible persons, speeding up the response process. Production data and the raw streaming data are combined in web-based workflows to create key performance indicators (KPIs) for every well.

Alarm validation is an important part of the monitoring workflow. Whenever a certain threshold is crossed, the monitoring engineer receives a notification and analyses the root cause of the problem, making a recommendation which is sent along with the validated alarm to the operator.

The ranking of the alarm is also important. It can be done by choosing a parameter such as deferred production, to prioritize the intervention and resources to the wells which generate the biggest losses first.

Pump operating conditions can also be monitored in real-time by using workflows. Production data, completion data and streaming data are combined in the computational engine to graphically plot the ESP operating point, like in Figure 4. Then, a comparison of this point with the most efficient operating range on the pump curve is done and the optimization of the artificial lift system can be tracked.

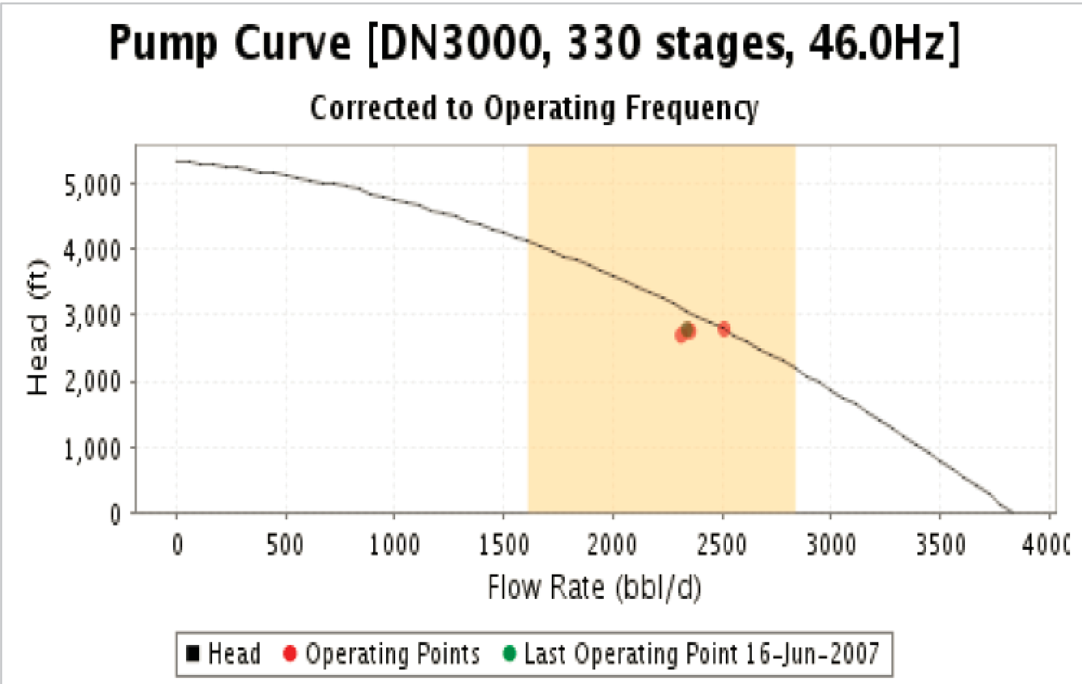

Figure 4: Real-time pump performance feed [4, p. 3]

A small group of experts can analyze reports of well uptime, well events and operating conditions, which are fed into the system automatically. This allows the analysis of multiple wells in a short time.

Diagnostic workflows

With the monitoring workflows conveying efficiency to the whole field, diagnostic workflows bring the next degree of improvement for a single well.

Diagnostic analysis is usually done offline, by modelling the inflow and outflow systems. Then, a recommendation is uploaded into the monitoring system, which is reviewed and actions are taken.

An optimization of both inflow and outflow systems is needed for an improved well production. For the issues in the lifting systems pump diagnostic workflows are used, while for the identification of chances to increase the capability of the reservoir/ completion system to deliver more fluid reservoir diagnostic workflows are used. This allows that an efficient entire production system is achieved.

Pump diagnostics involve timely analysis of measurements in order to check the performance of the lifting system and optimize it. Pump operating parameters for stable conditions are compared to the actual pump test curve to detect and monitor inefficiencies in the system. A trend is made with the problems and their impact on electrical consumption or deferred oil. Recommendations are then made based on economic influence and operators can prioritize interventions.

Pump performance analysis is alarm based, meaning that it is done each time the pump functions in unusual conditions and triggers an alarm. For a pump functioning properly over a long period of time, a regular checking of the system is done to detect chances for optimization.

Reservoir diagnostics involve an analysis of the transient pressure, from the pump intake to the other nodal points, to evaluate the productivity of the reservoir and possible actions to enhance production. Bottomhole transient pressure data can be captured on well start up or shut down and used to determine reservoir performance. On such events like a shutdown, pressure is monitored live to decrease the shut in time and enhance interpretation. Reservoir diagnostics is done for each well when it is not producing as it should and pressure data recommends a well test. It can be helpful in determining both near wellbore and far-field conditions.

People

A team of experts in artificial lift, production and reservoir provides recommendations aimed to speed up the decision making process. Monitoring engineers are in charge of the workflows based on real-time data while diagnostic engineers, production engineers and reservoir engineers help in optimizing the whole production system.

Case studies

The following examples show the benefit of having a standardized infrastructure and a set of workflows.

Case 1. Preventing failure by taking action

A well producing high volumes and having high productivity index (PI) triggered an alarm with warning messages on high pump intake pressure and low average motor current. A screenshot of the monitoring system is shown in Figure 5 below. The thresholds for efficient operation are set by the red horizontal lines.

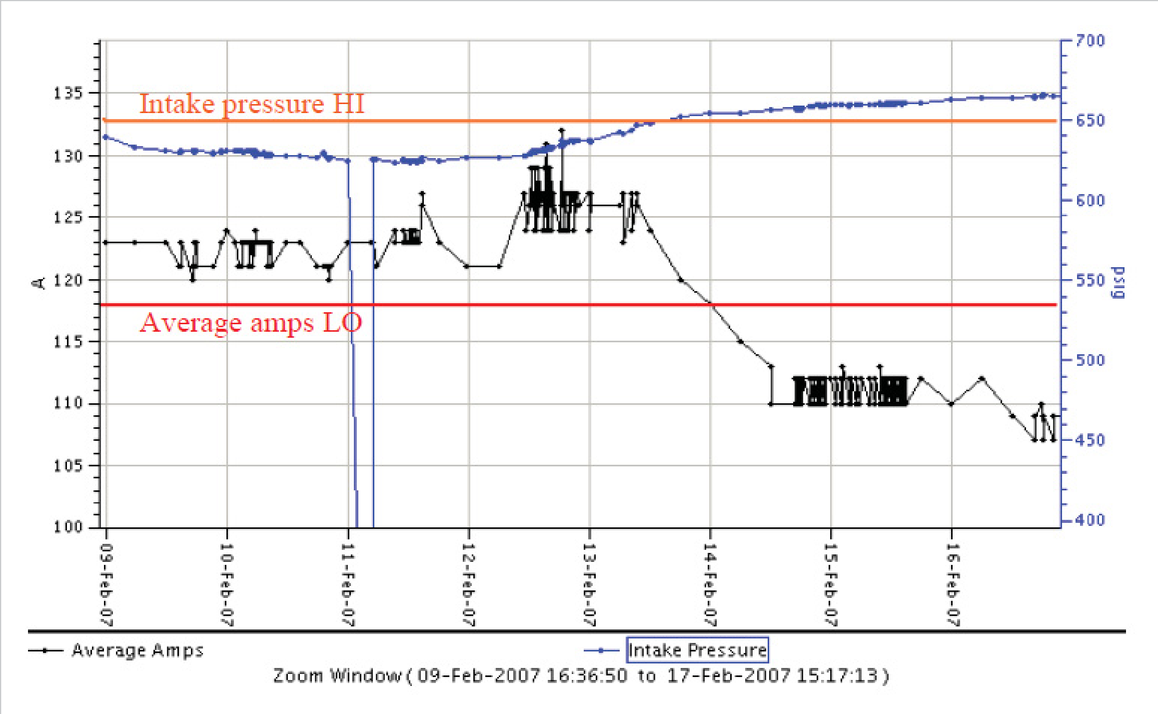

Figure 5: Trend analysis indicating a problem [4, p. 4]

Two possible reasons for the behavior were computed automatically by the virtual advisor implemented in the monitoring system: a tubing leak or a pump failure. A well test was ordered for the particular well, which showed a 20% decrease in production. This, combined with a trend analysis of the involved parameters and the detection of increased system vibrations concluded that the pump is degraded. A pump failure would have happened very soon if it continued operating. The unit was replaced and production was safely restored. A deeper analysis of the broken pump confirmed its bad condition, and that its replacement was a proactive decision allowed by the real-time monitoring of the well.

Case 2. Monitoring and diagnostics effect on increasing equipment run life

Run life of the ESP pumps is a critical driver for success in production operations, as the meantime between failure has the main influence on the economics. The figure below shows the equipment parameter plot for a very low volume producer well, during year 2005. It can be seen that the well was shutting down very often because of the motor heating up excessively. The reason for this behavior was that the volume of gas was too high at the pump intake. The pump was shut down each time a parameter deviated from the safe threshold, in between which the system operated without failure. A 60 days run time between workovers was reported for the well illustrated below, in Figure 6.

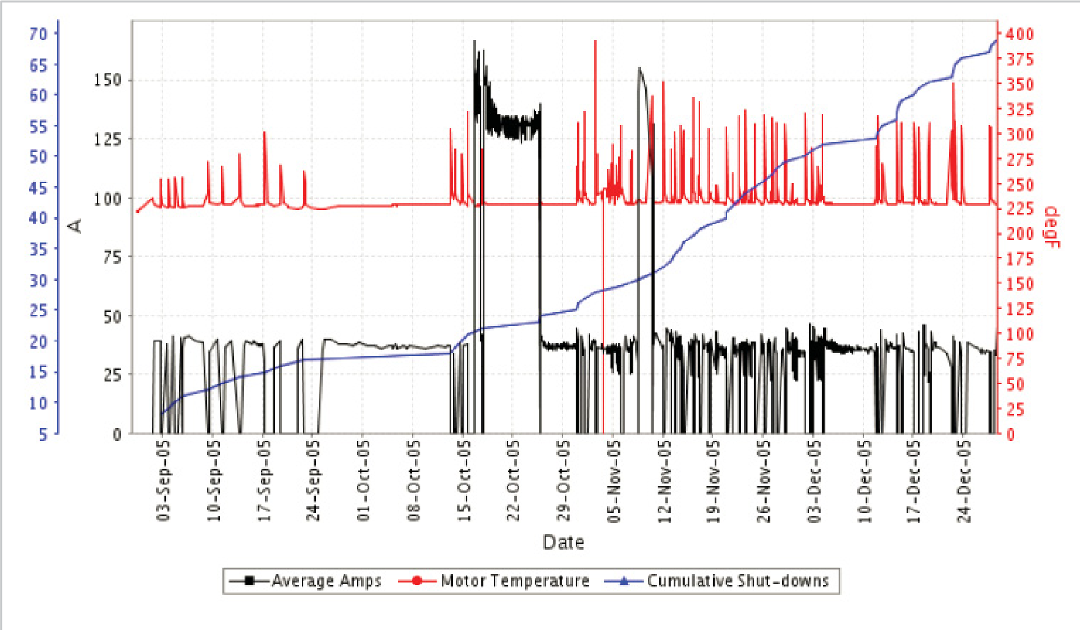

Figure 6: Well parameters plot between August and December 2005 [4, p. 4]

After the analysis of the parameters trend, it was decided to add a set of perforations and set the equipment lower in August 2005, which resulted in an increase of equipment run life from 60 to 122 days.

The next step was an analysis of the production data, which showed that the top perforations generated most of the liquid production. The pump was sitting lower than that, so insufficient liquid was flowing to cool down the motor. With help from the monitoring data, the unit was moved up around 200 ft. on January 2006, above the top perforations. Again, the result was an increase in run life from 122 to 465 days.

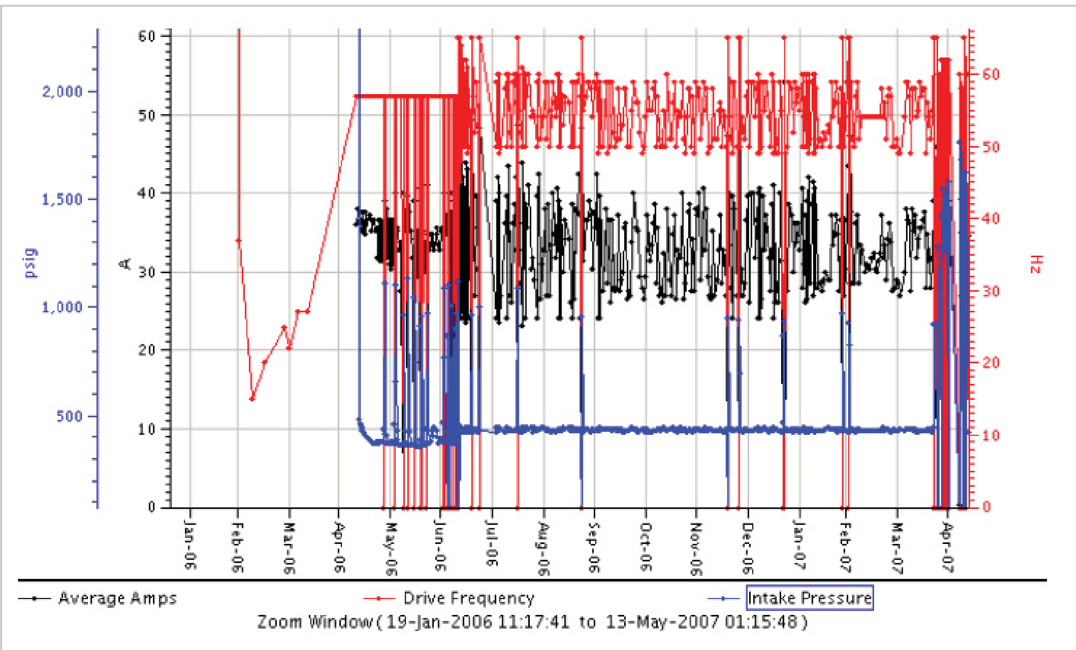

Figure 7: Well parameters plot between January 2006 and May 2007 [4, p. 5]

After continuous monitoring of the parameters, a considerable gas interference level was detected. This can be seen on the plot in Figure 7 as the fluctuations on the motor current (around 15 amps in this case). The built-in advisor of the monitoring system recommended that the drive frequency of the pump is reduced, to lower the effect of gas at pump intake.

The pump was raised around 600 ft and the drive frequency was reduced to below 60 Hz in a workover in May 2007. Visible in Figure 8 is the drop in gas interference ever since.

The quantification of the results of monitoring and analysis for the well mentioned above were a 4 times increase in equipment run life (from 122 to 465 days), a 15% increase in well uptime, an incremental production worth $100000 and equipment savings of $60000 (reference values calculated at the end of the optimization cycle). [4]

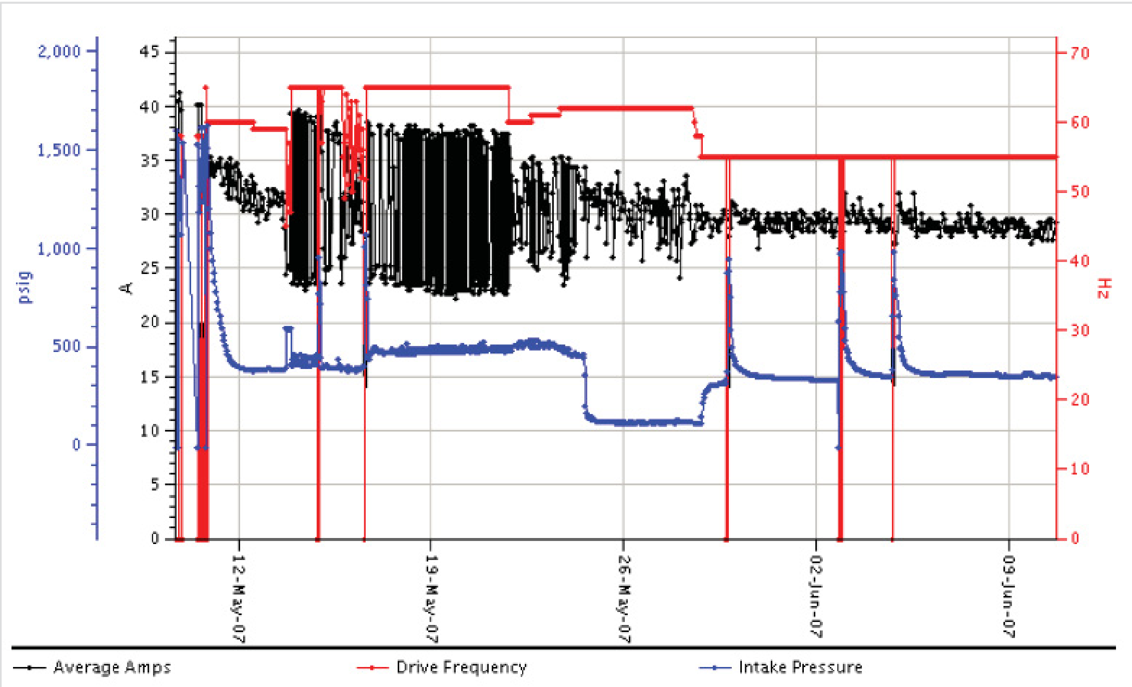

Figure 8: Well parameters plot between May 2007 and June 2007 [4, p. 5]

3.2 Shell

Due to the development in technology, remote monitoring of fields from the office has increased significantly over the last years.

In Shell, over the period 2002 – 2009, a Smart Fields Platform has been implemented, which brought the company paybacks in order of $5 bln. The applications covered both the addition of new technology to older systems and smart design in new ventures. Value is assessed after closing the Value Loops, which comprise of data acquisition, modelling, decision making, and field execution.

Smart Fields incorporate a variety of solutions in Shell’s production and processes. “Smart fields Foundation” is a standard solution that lays the groundwork for live monitoring and optimization of the well, data procurement, production optimization based on a specific model, and prediction. Some examples consist of virtual metering, live well monitoring and optimization, off-line linked to hydrocarbon allocation and *Integrated Production System Modelling (IPSM)*.

A standard architecture is designed to incorporate all systems in the process control domain. The *Data Acquisition and Control Architecture (DACA)* standard delivers the safe connection between office and field. Staff is aided by predefined standard workflows, in order to allow the execution of the right process steps and right-time collaboration, which supports assets in accomplishing full potential.

Adopting smart wells can have an influence on the production of the field. For example, a system with automated downhole valves can be used to regulate well production rate and flow from the reservoir, increasing the efficiency of the recovery. Another example of smart fields is wells that allow commingled production, while assigning a truthful production to each separate reservoir.

Shell has implemented different smart capabilities in its assets, based on the business needs and particular operating conditions. It is much cheaper to design a smart system from the beginning, rather than adapting it after initial construction.

To illustrate the benefits of live monitoring and virtual metering of wells, the example of Salym group of oilfields in Western Syberia can be chosen. The exploitation is a joint venture between Salym Petroleum Development and Shell in operating and developing the Salym field. It consists of 300 wells which function on artificial lift (mostly ESPs). They have been adaped with pump controllers and wellhead equipment that feed into a SCADA system. Shell's Smart Fields Foundation standard has been gradually implemented, including the *Fieldware* software package, which is divided in 4 sub packages:

Production Universe – live virtual metering of fluids and downhole parameters

ESP – live pump efficiency and fluid level monitoring, illustrated in Figure 9 and Figure 10 below:

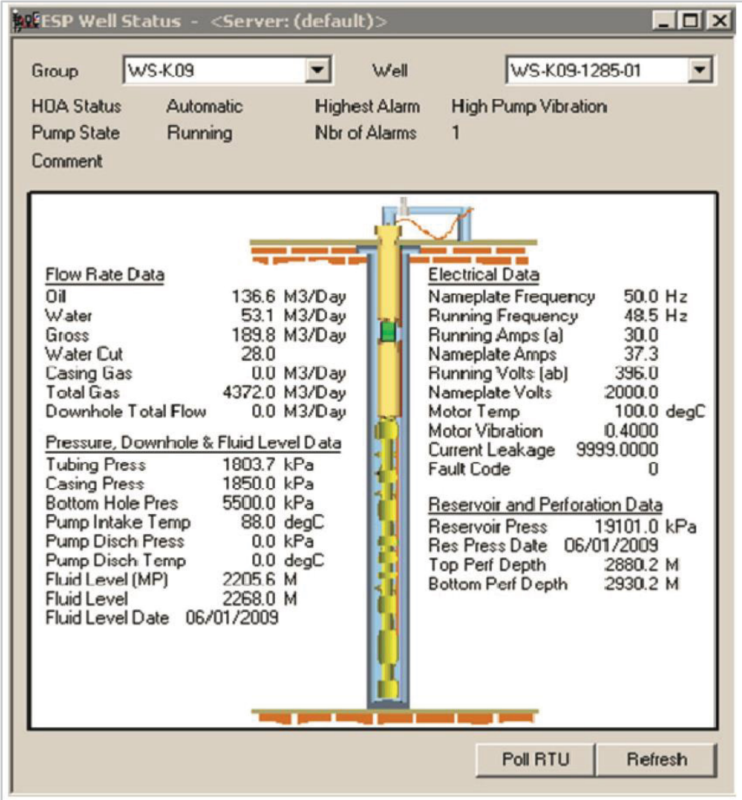

Figure 9: ESP Monitoring with FW ESP [6, p. 4]

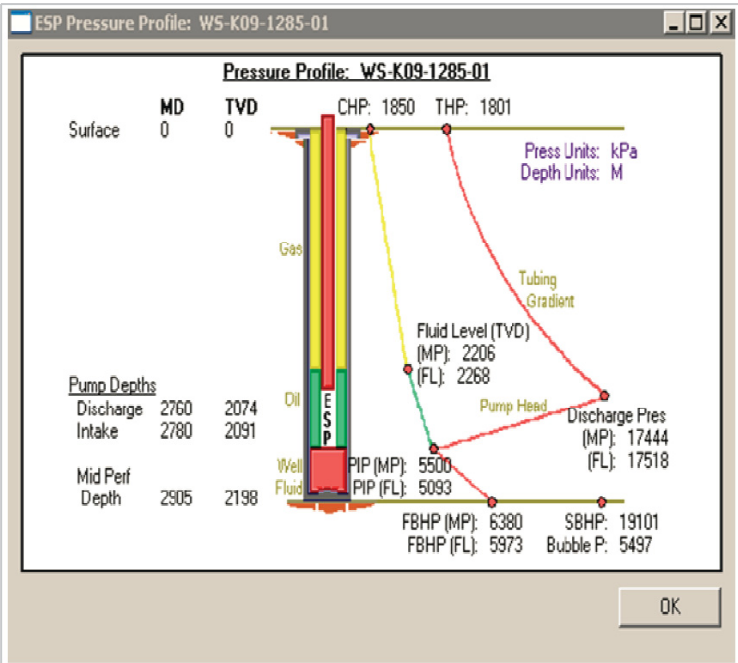

Figure 10: Investigation Screen in FW ESP displaying the fluid level above pump and the pump pressure profile [6, p. 4]

Production Universe EOR – water injection optimization by live monitoring of the pressure in the injection wells and water flow from source to injection

WellTest – providing live testing data which allows the optimization of the well test.

The advantage of using such a system is the optimization of production by earlier identification and remediation of well issues, reduced failure due to early warning, live gas lift distribution optimization, and more reliable production allocation resulting in information essential to reservoir management. Furthermore, HSSE risks are reduced and oil recovery increases. [6]

4 Production losses classification criteria

The petroleum industry has several main concerns and along with safety, reducing production losses is on the top of the list. For most operator companies, reducing the losses even by 5 to 10% would already have a significant impact on profitability.

Losses at well level can be classified by several criteria like loss type, loss anticipation, and root cause, all of which are described below.

4.1 Loss type

In this category there are two types of production losses: deferments and actual losses.

A deferment is the reduction in production availability caused by an activity, breakdown, trip, poor equipment performance, or sub-optimum operations, that results in a reduction in the volume sold or injected, delaying the production or injection until some later time.

Actual Losses are that part of the integrated production system capacity that could have been delivered to customers but is not, due to leaks or theft.

4.2 Loss anticipation

This category has two types of production losses: planned losses and unplanned losses.

Planned losses: These losses usually occur due to predicted maintenance and are caught into the yearly production proposal.

Unplanned losses: These losses occur due to electrical breaks, shutdowns or overestimates and are not predicted in the yearly production proposal.

4.3 Root cause

In this category, production losses are tracked back to their route cause, which could be for multiple reasons like corrosion, fatigue, age-wear, carbonate buildup, sand buildup, load stress, human error, calamities, etc.

5 Production losses in OMV Petrom

This chapter will explain how production losses are recorded, categorized and approved in OMV Petrom.

5.1 PIMMS

A standard procedure is used for the process of recording and reporting the oil and gas production losses for the entire E&P. It is named PIMMS (Production Information Management & Monitoring System). PIMMS is an application implemented to introduce and centralize the oil and gas production data. The objective of the application is to ease the access to information to responsible persons and speed up decision making.

5.1.1 Daily production process

Daily production processes are: input and validation of the daily data, daily allocation of production per well and generation of the daily/weekly/monthly production reports.

A graphical representation of the daily production process is shown in Figure 11:

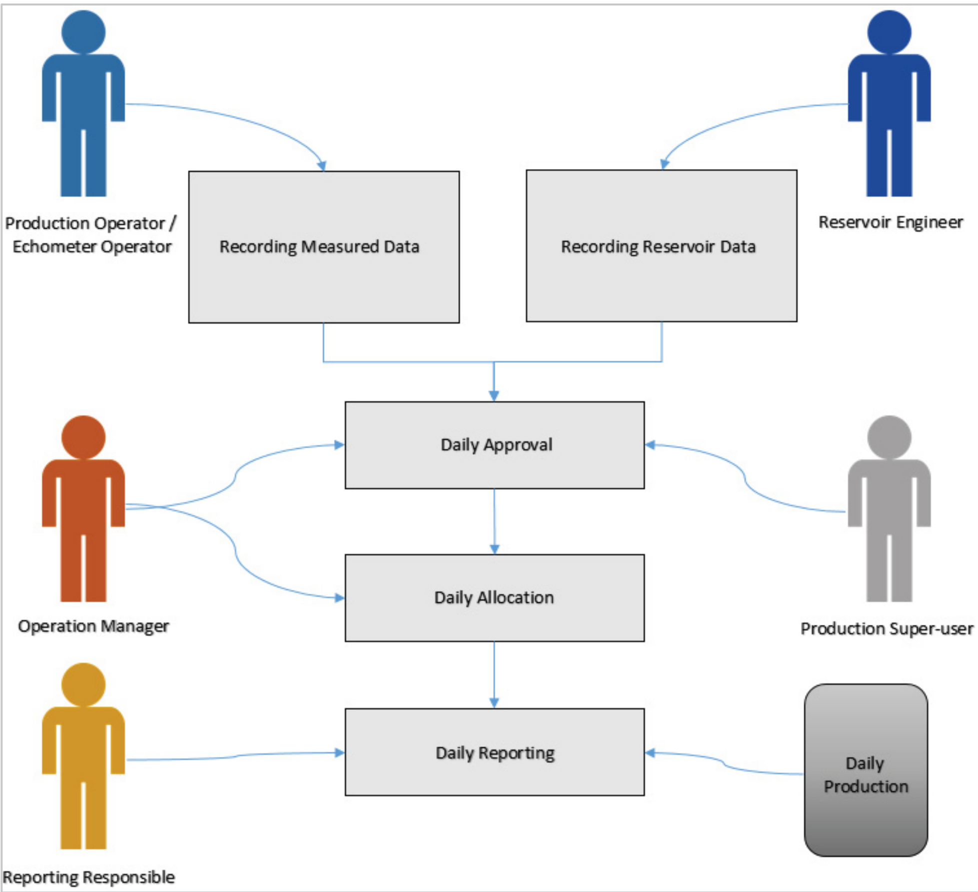

Figure 11: Representation of the daily production process

Production levels

The **Production Potential** is the maximum production which can be provided by a well in normal functioning conditions (geological and technical). It is established based on 3 representative well measurements based on the specific production conditions, or based on empirical calculations taking into consideration well productivity and production conditions. This is a monthly reference for the production analysis and establishes the production capacity of a well in certain conditions.

The **Reference Production** is the 24 hours-per-day production value of the last approved well test.

The **Theoretical Production** is the reference production rate corrected by off deferment time. E.g. 20hours/24 hours.

The **Allocated Production** is the theoretical production corrected by back allocation – official production of a well, which is calculated in accordance with delivery, pumping and existing stocks in oil parks and tank farms or in accordance with gas consumption/losses in the existing facilities.

A **Well Test** is the sampling and measurements of the oil and gas production per well, performed centrally at production parks' separators and/or treatment storages, or individually per well. The well test can be done for a 24 hours interval, or other time intervals and calculated (extrapolated) for 24 hours. If the well test/measurement is done and accepted for the 24 hours interval it is considered a fixed measurement and it is recorded in the system accordingly.

In some cases it is mandatory to avoid modifications of the measured data during well tests by the back-allocation process (e.g. new wells). In these special cases the calibration (well test) is considered fixed if the following conditions are met:

- Well is calibrated for 24 hours
- Well is calibrated from 7:00 AM to 7:00 AM

If there are inconsistencies between the calibration data and the daily updated data in the tank stock and pumping/transfer from tank to truck, than the data resulting from back-allocation process will be inconsistent.

Loss reasons

Losses due to well performance decrease represent, by definition, the difference between well production potential and well reference production (last accepted well test) at a certain point in time.

Losses due to well shut down represent, by definition, the production losses compared to the last accepted production well test. For example: if the well with 3 to/d well test has 8 hours shutdown time, then the losses due to the shutdown are 1 to/d and allocated production is done at a theoretical production of 2 to/d.

The **Allocation difference** represents the difference between the production calculated based on the stock measurements and pumping /deliveries volumes and the sum of theoretical well production, or the difference between the gas deliveries plus the sum of gas losses/consumptions and sum of theoretical gas production.

For an improved understanding, the different production levels along with the reasons for the difference between them are illustrated in Figure 12, below:

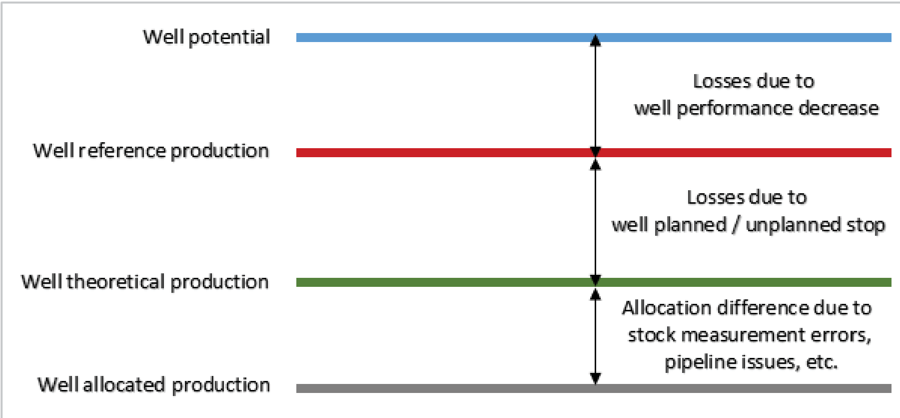

Figure 12: Different well production levels

To calculate the daily production the ‘stock by stock’ equation 1 is used: (PIMMS fundamental equation):

$$Stock_{7:00AM\ yesterday} + Production - Pumping\ or\ delivery = Stock_{7:00AM\ today} \qquad (1)$$

Production losses calculation:

The equation which calculates the production losses based on the potential takes into account the inputs, outputs, and allocated production which is calculated with equation 1 as shown below in equation 2:

$$Production\ Potential + (Inputs - Outputs) in\ or\ from\ production - Production\ Losses = Allocated\ Production \qquad (2)$$

Production Inputs represent everything that is above the reference or allocated production and the potential level (resulting from a well intervention; e.g.: increase of the choke, change of a pumping element, etc.), or wells that don’t have a production potential during the current month but start production in current month (e.g. a new well or a well after workover, a well stopped on a long term, etc.).

Production Outputs represent everything below the potential, in case of the wells which have production potential in the current month but stop producing at a certain moment (well status changes from “well in production” to “well closed on the long term”)

For **Production Losses**, the difference between the well potential / sum of all wells potential and the allocated production is considered.

Production losses of a structure (Well, Separation Park, Sector, Production Zone) or commercial field can be split in:

- Losses due to well performance decrease (Low Deferment)
- Losses due to well shutdown
- Differences due to the allocation process

Detailed information on losses due to well performance decrease (Low Deferment)

Losses due to well performance decrease are not included into the back-allocation process. These are used just for justifying a loss and to allow the intervention where the difference to the well potential is big. To justify a loss it is necessary to evaluate the reason and sub-reason that led to this loss. These losses are mandatory to be uploaded in the system before the back-allocation process is run.

Mandatory rule for each well:

If the reference production (=the 24 hours-per-day production value of the last approved well test) is lower or higher than the well potential, than the reason and sub reason must be stated in the ‘Losses due to well performance decrease’.

Types of losses due to well performance decrease (reason and sub reason) are shown in Table 1:

Table 1: Types of losses due to well performance decrease

No.	Main Reason	Sub-Reason
1	Reservoir management	Choke size change
2	Reservoir management	Pumping unit elements change
3	Performance decrease	Pumping system efficiency decrease
4	Performance decrease	Gas-lift system efficiency decrease
5	Performance decrease	Weak wells*
6	Performance decrease	Watercut increase*
7	Performance decrease	Total flowrate decrease*
8	Performance decrease	Layer blocked (around the wellbore)
9	Performance decrease	Gravel pack/ screen blocked
10	Performance decrease	Workover fluid recovery
11	Performance decrease	Well sanding
12	Performance decrease	Unknown reason
13	Surface works to well facilities	3rd party pipeline maintenance (external Petrom)
14	Surface works to well facilities	Petrom pipeline maintenance
15	Surface works to well facilities	Problems in gas compressors
16	Surface works to well facilities	High pressure in 3rd party system (external Petrom)
17	Other	Other
18	Other	Loss between 0 – 2 %

***Example for an oil well**:

A well which has the following potential:

$$\frac{1\ m^3}{day} *\ 50\%\ watercut = \frac{0.5m^3}{day}$$

Becomes:

A **Weak well** when the well produces, but the reference production is:

$$\frac{0.8m^3}{day} * 60\%\ watercut = \frac{0.32m^3}{day}$$

A **Watercut increase well** when the well produces with same gross volume but higher water-cut percentage, and the reference production is:

$$\frac{1m^3}{day} * 60\%\ watercut = 0.4\frac{m^3}{day}$$

A **total flowrate decrease well** when the well produces with a low flowrate but with the same water-cut percentage, and the reference production is:

$$\frac{0.8m^3}{day} * 50\% watercut = 0.4\frac{m^3}{day}$$

***Example for a gas well**

A well which has the following potential:

$$\frac{1500\ Sm^3}{day}, \frac{10m^3}{day}, choke\ size\ ^{\Phi}10\ mm, WHP = 15bar$$

Becomes:

A **Weak well** when the well produces, but reference production is:

$$\frac{1000\ Sm^3}{day}, \frac{10m^3}{day}, choke\ size\ ^{\Phi}10\ mm, WHP = 10bar$$

A **Watercut increase well** (liquid* flowrate increase) when the well produces with same gross volume but higher water-cut percentage, and the reference production is:

$$\frac{1000\ Sm^3}{day}, \frac{15m^3}{day}, choke\ size\ ^{\Phi}10\ mm, WHP = 10bar$$

A **Total flowrate decrease well** when the well produces with a low flowrate but with the same water-cut percentage, and the reference production is:

$$\frac{1000\ Sm^3}{day}, \frac{8m^3}{day}, choke\ size\ ^{\Phi}10\ mm, WHP = 10bar$$

*Observation: liquid = water and/or condensate

A well can be recorded in PIMMS for of the above categories with an unknown loss reason for a limited time (maximum of one month) during which the well responsible makes all the necessary tests (for example echometer measurements) and establishes the reason for the well parameters change, subsequently recording the well into “Losses due to well performance decrease” to the sub category “Well performance decrease” or “Reservoir management”, depending on the analysis result.

Detailed information on losses due to well shutdown (Well Off Deferment)

“Losses due to well shutdown” are recorded each time the well is stopped.

If a well is waiting intervention or workover, than an approved working program must exist.

Well stop due to technological breaks (intermittent production) is not considered a production loss.

Loss types (reason and sub-reason) included in this category are shown in Table 2:

Table 2: Types of losses due to well shutdown

No.	Main Reason	Sub-Reason
1	Well intervention	Intervention activity type
2	Waiting intervention	Waiting intervention
3	Well Workover	Workover activity type
4	Waiting Workover	Waiting Workover
5	Surface works	Other surface system disruption
6	Surface works	Other surface (planned) maintenance
7	Surface works	Pipeline/manifold frozen
8	Surface works	Broken Petrom pipeline
9	Surface works	3rd part broken pipeline (external Petrom)
10	Surface works	Petrom pipeline maintenance

11	Surface works	3rd party pipeline maintenance (external Petrom)
12	Surface works	Compression problems
13	Surface works	High pressure in 3rd party system (external Petrom)
14	Electrical system	Petrom electrical system breaks
15	Electrical system	3rd party electrical system breaks (external Petrom)
16	Electrical system	Petrom electrical (planned) maintenance
17	Electrical system	3rd party electrical (planned) maintenance (external Petrom)
18	Downhole equipment damaged	Casing damaged
19	Downhole equipment damaged	Object dropped in the well
20	Calamities	Land slides
21	Calamities	Flooding
22	Calamities	Other
23	Other reasons	Land owner problems
24	Other reasons	Waiting to be put into production
25	Other reasons	Waiting IOR/EOR measures to increase oil recovery
26	Other reasons	Stopped due to the economic limit
27	Other reasons	Stopped for in-situ measurements (build-up tests)
28	Other reasons	Other delivery problems

5.1.2 Responsibilities

Production parks operators are the people responsible to record the data into one of the categories “Losses due to well performance decrease” or “Losses due to well shutdown”.

The sector manager in charge of the particular wells/parks is responsible for the daily verification and approval of the production loss category assignment. [7]

5.2 Loss categories definitions

Following is a description of the production loss categories that are recorded In OMV Petrom. Not all of them contain the root cause of the loss, as they are recorded by an operator which might not be aware of the loss reason at the point of the loss detection.

Electrical breaks are losses caused by the stoppage of the electrical power.

Surface works represent surface maintenance & repair carried out by a maintenance crew (not an intervention crew). This is solely related to the well and the flowline from the well to the park (excluding broken pipes) E.g. Maintenance or repair of Christmas tree, pumping head, pumping unit, flowline valves, derricks, electric or thermal motors, heaters.

Calamities refer to natural events causing stoppages in production.

- Blocked access roads (e.g. by landslides, floods)
- Damage caused by weather conditions (e.g. Derrick damaged by wind)

High Pressure losses are caused by anything that prevents gas export. E.g. High pressure in the Transgaz* (*company responsible for the transport of oil and gas) pipeline preventing gas export, customers unable to receive gas, broken Transgaz pipeline or maintenance to Transgaz pipeline.

Broken pipes are damaged Petrom pipelines (not Transgaz). This includes both flowlines and export pipelines.

Frozen pipes are damaged Petrom pipelines (not Transgaz). This again includes both flowlines and export pipelines.

Stopped for tests is a loss category for wells that are stopped for pressure build-up tests, static or isochronal tests.

Stopped for technical & geological solutions - this does not include geological measures such as perforation & re-perforation.

Includes:

- A well that is waiting for the results of geological tests from another well
- Beam pump optimization, e.g.: stopped the well to increase stroke length, pumping speed
- Cyclic steam injection/stimulation

Stopped at economic limit refers to functioning wells that are stopped at the economic limit during the month. At the end of the month, well potential is adjusted to zero, losses do not appear in Outputs.

Problems in the compression plant are compression failures. E.g.: for gas lift wells, gas wells, and wells with associated gas.

Land owner problems are clearly explained by their title.

Steam injection - includes the period after steam injection during which the well is producing below potential.

Others - all other losses, but the exact explanation must be filled in. Could Include:

- Dewaxing without intervention crew (e.g. pumping hot liquid down well)
- Recovery of fluids injected into reservoir (e.g. hot water, oil, other treatments)
- Losses due to the well producing mud
- Lack of tanks or other physical impediments to delivery of oil

Interventions – all types of interventions, as defined in the Interventions Management Tool (PIMMS additional tool)

Waiting interventions - this applies only in situations where there is zero flow from the well, and there is a period of zero flow until the intervention crew arrives.

Weak wells, when production is below potential due to under-performing well equipment (not due to reservoir causes). E.g.: worn out pump, gas in the pump.

- An underperforming well, for which the cause is unknown, is defined as a weak well until the cause is known, whereupon it can be reclassified into another category
- A well waiting for flow after intervention or workover
- A well is still classified as weak once it has been decided to do a workover, but the well can continue to flow.

Watercut increase – when the well produces with same gross volume but higher watercut percentage (this includes watercut due to reservoir decline, as well as watercut that could be rectified by intervention or workover)

Decreased flow, losses due to reservoir decline, when the well is producing with a low flowrate but with the same water-cut percentage.

Workover – includes losses due to major downhole operations excluding all defined as interventions in the Interventions Management Tool (PIMMS additional tool)

Waiting workover - this applies only if there is total failure of the well, resulting in zero flow, so there is a period of zero flow until the workover crew arrives. [8]

5.3 Losses on sector level

Independenta is an OMV Petrom production sector located in Galati county, Romania, whose production started in 1959. It is one of the key brownfields in the company portfolio, covering 7% of whole company domestic production by 2014. A Digital Oilfield Pilot Project was deployed in Independenta, starting with 2010. All the 405 wells in the field have a PCP artificial lift system installed, fitted with well automation and Variable Frequency Drive SAM units. 5 of the wells have corrosion inhibition skids attached and 2 of the wells have an Automatic Fluid Level Monitoring System installed (MURAG 20). All the wells feed the data into XSPOC, which is a well management SCADA used for monitoring and intervention.

An analysis with the top 10 loss categories in Independenta for the years 2014 and 2015 is presented in the next two charts. The loss categories shown are the ones defined earlier, in chapter 5.2.

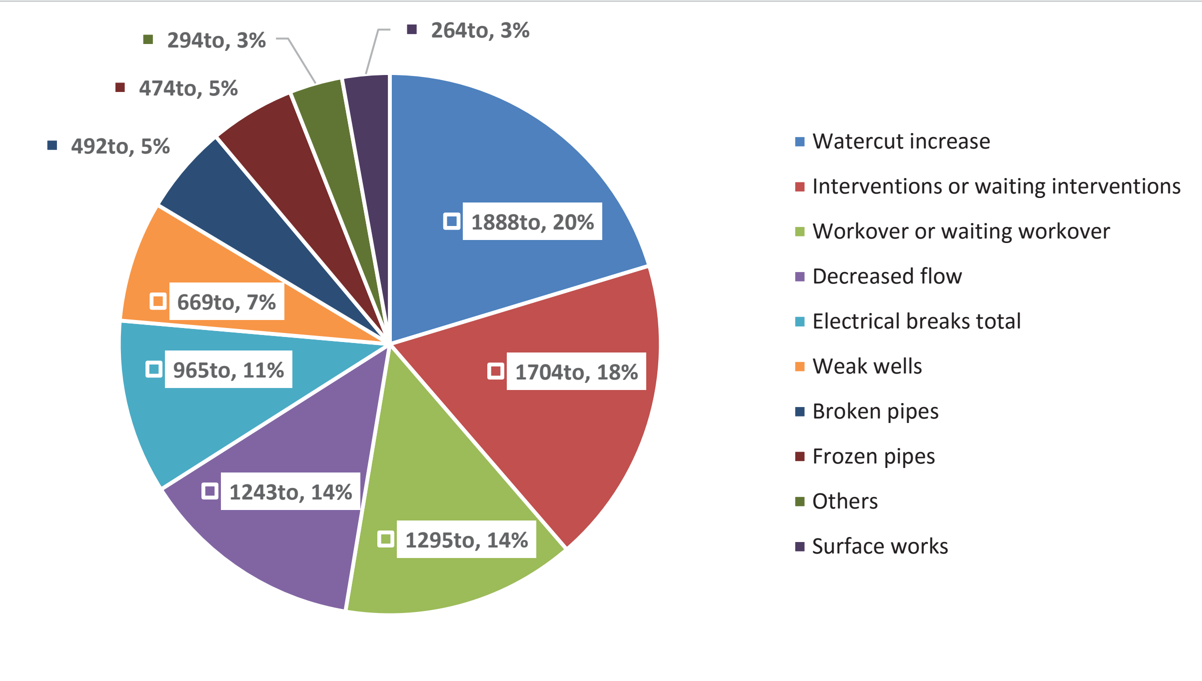

Figure 13: Production losses on sector level (Independenta) for the year 2014

Figure 13 shows that in 2014, the biggest loss category is ‘Watercut increase’, totaling 20% of the losses and 1,888 tons. It is followed closely with 18% and 1,704 tons by wells on ‘Intervention or waiting intervention’ and by wells on ‘Workover or waiting workover’ with 14% and 1,295 tons. The smallest loss category illustrated is ‘Surface works’, accounting for 3% of the losses and 264 tons in volume.

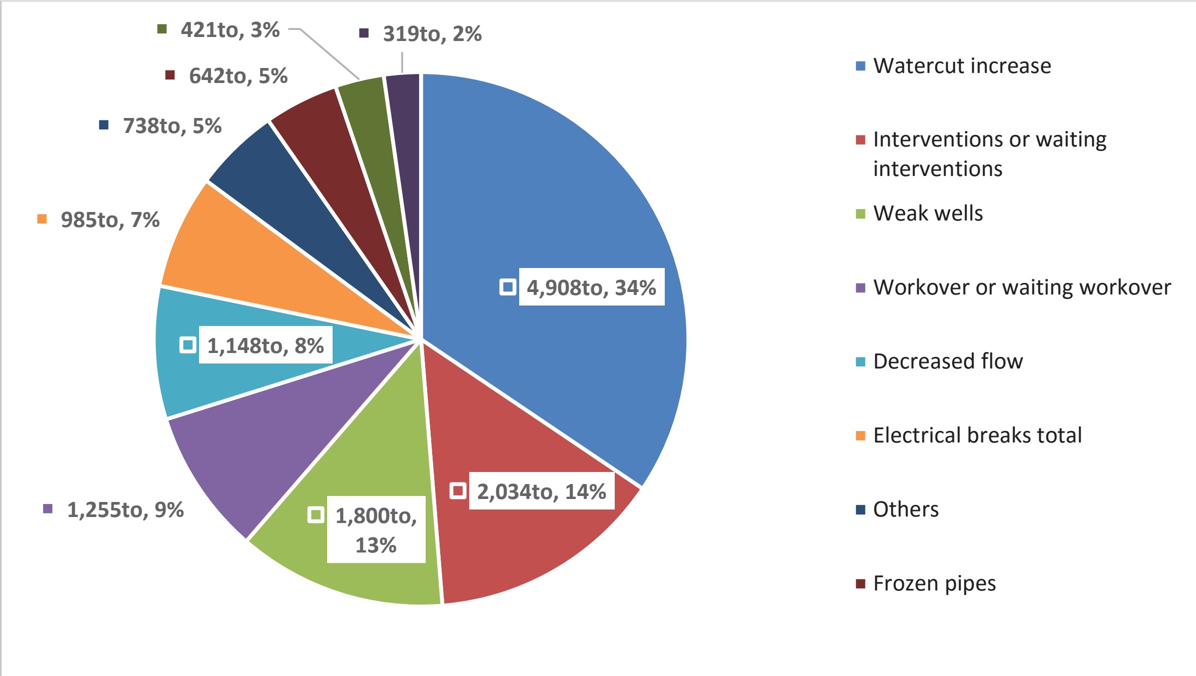

Figure 14: Production losses on sector level (Independenta) for the year 2015

In 2015, as shown in Figure 14, the biggest loss category is 'Watercut increase' with 34% of the losses and 4,908 tons lost. Wells on 'Intervention or waiting intervention' yield a 14% loss and 2,034 tons, while the third biggest category is 'weak wells' with 13% of the total losses and 1,800 tons lost.

The category with the least losses of the analysis is again surface works, with a coverage of 2% of the losses and 319 tons.

5.4 Losses on company level

The domestic producing assets of OMV Petrom Upstream are organized in 8 onshore Assets and 1 offshore Asset, and subdivided into 38 onshore production sectors and 1 offshore production sector. The view on the whole company level is a bit different, encompassing the losses in different proportions.

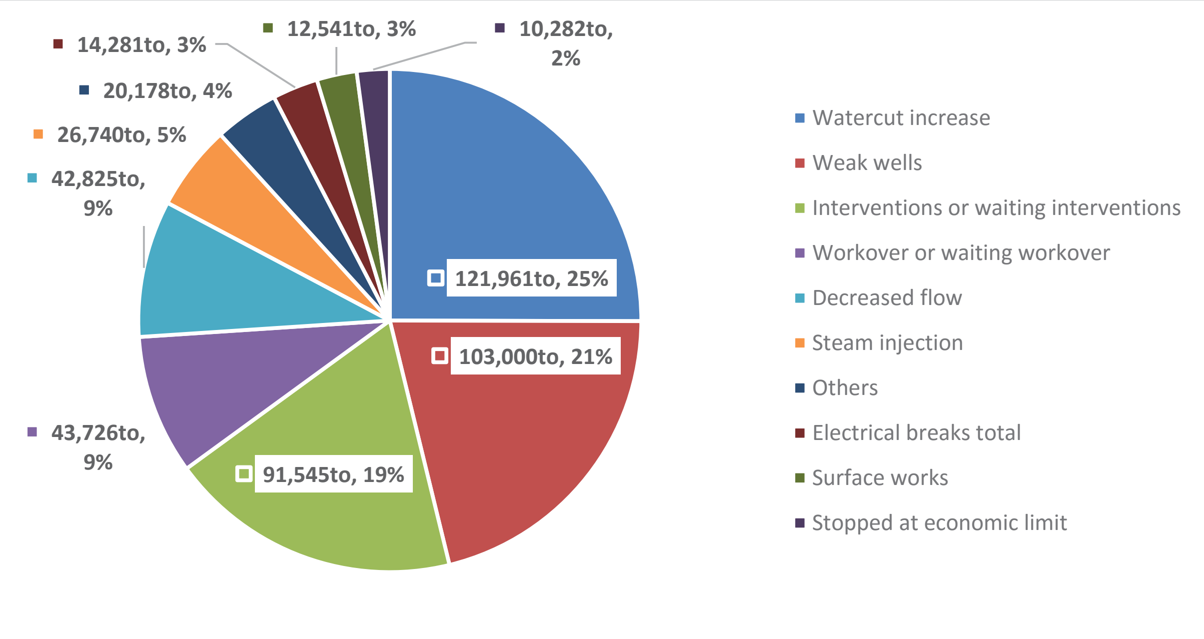

Figure 15: Production losses on company level 2014

Figure 15 shows that in 2014, 'Watercut increase' is leading the loss categories with a 25% share and 121,961 tons lost. 'Weak wells' follows with 21% and 103,000 tons lost. The third biggest loss category is wells on 'Intervention or waiting intervention'. Wells 'stopped at economic limit' account for the least amount of loss, 2%, respectively 11,071 tons.

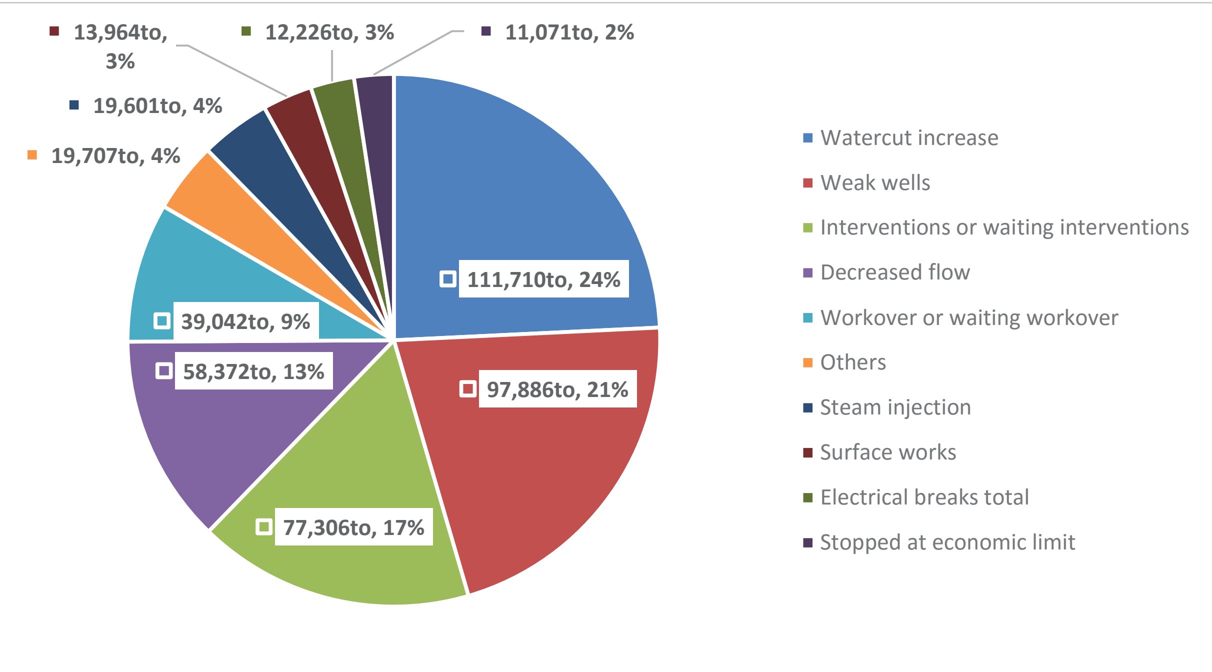

Figure 16: Production losses on company level 2015

In 2015, as can be depicted in Figure 16, 'Watercut increase' generates 24% of the losses and 111,710 tons lost, 'weak wells' 21% and 97,886 tons, while wells on 'Intervention or waiting intervention' cause 17% of the losses and 77,306 tons lost. The smallest loss is generated by wells 'Stopped at economic limit' with 2% of the losses and 11,071 tons lost.

Compared to the view on sector level, on company level 3 new loss categories account for the major losses: 'Steam injection', 'Others' and 'Stopped at economic limit'. They range in loss coverage between 2 and 5%. However, attention should be payed to each category illustrated above, because even reducing 2% of the losses would produce an incremental 10,000 to 11,000 tons of oil per year, which is a significant quantity.

5.5 Impact of unplanned losses

The impact of unplanned losses in wells is the following:

- Lower production level
- Reduced MTBF
- Lower production efficiency
- Higher OPEX / maintenance costs
- Wells reaching economical limit earlier
- Increased HSSE risk

In the end, without corrective measures applied, the KPIs described in chapter 9 are affected negatively.

5.6 Correlation between loss categories

5.6.1 Downhole pump failure – electrical breaks correlation

This analysis has been done on company level, integrating all 8 onshore assets, considering all the wells on artificial lift equipped with sucker rod pumps or progressive cavity pumps. The time interval under investigation is 2014 – 2015, with the results and conclusions for each separate year presented below. For all the pump failures, an investigation was started in the company's pump repair workshops, where the exact failure reason has been labeled to each pump.

5.6.1.1 Downhole pump failures in 2014 within 4 days after electrical breaks

For the year 2014 an incremental, asset by asset view of the number of downhole pump failures happening within 4 days after an electrical break has occurred is presented in Figure 17. There were a total of 299 pump failures within this period. The asset with most reports is asset 1, with 95 failures, while asset 7 reported only 1 failure.

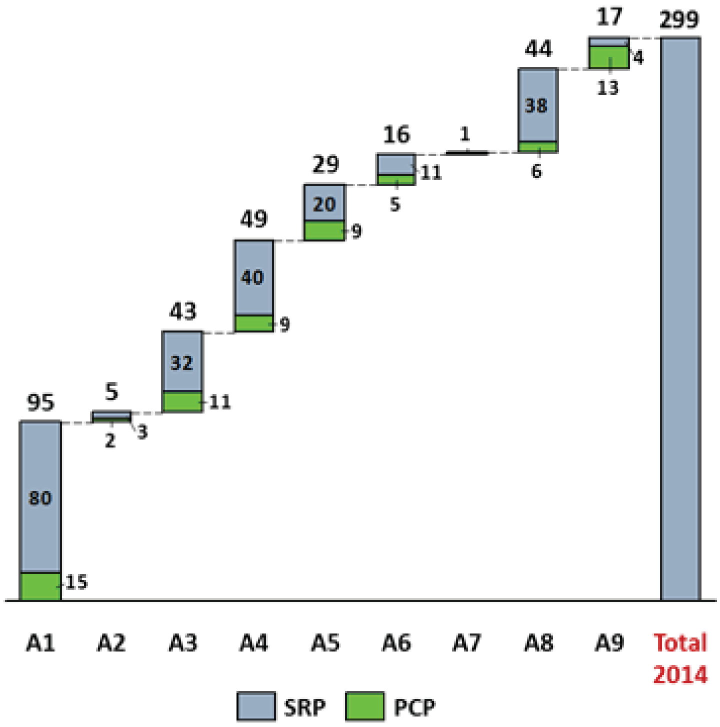

Figure 17: Total number of downhole pump failures for ALL REASONS after the occurrence of electrical breaks in 2014

Figure 18 shows the number of pump failures caused only by sand reasons in 2014, which represents a total of 142 failures counted within the first 4 days after an electrical break.

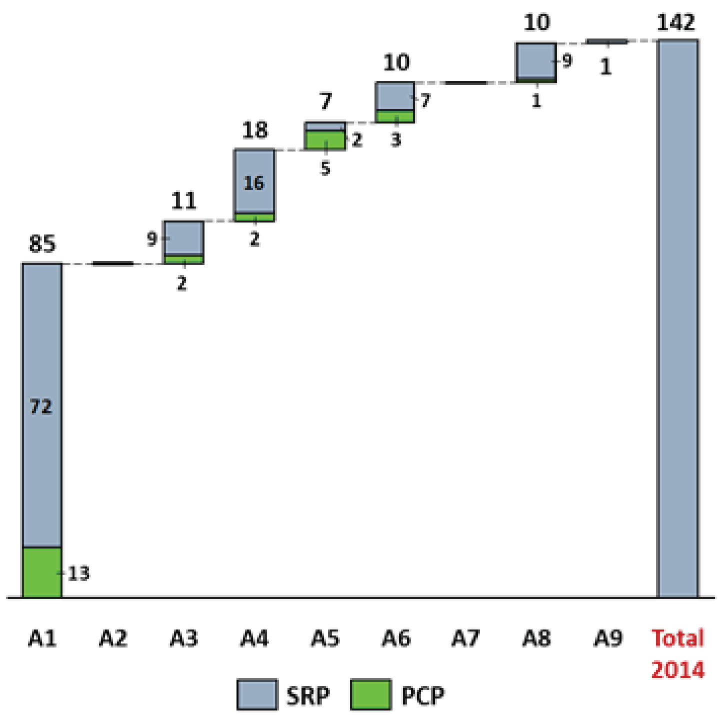

Figure 18: Total number of downhole pump failures for SAND REASONS after the occurrence of electrical breaks in 2014

5.6.1.2 Downhole pump failures in 2015 within 4 days after electrical breaks

In 2015, a decrease in the total number of downhole pump failures is illustrated in Figure 19, which as well refers to the failures that occurred within 4 days after an electrical break. The asset with most reports was asset 5, totaling 39 failures, while asset 1, 3, 4 and 9 reported no failure.

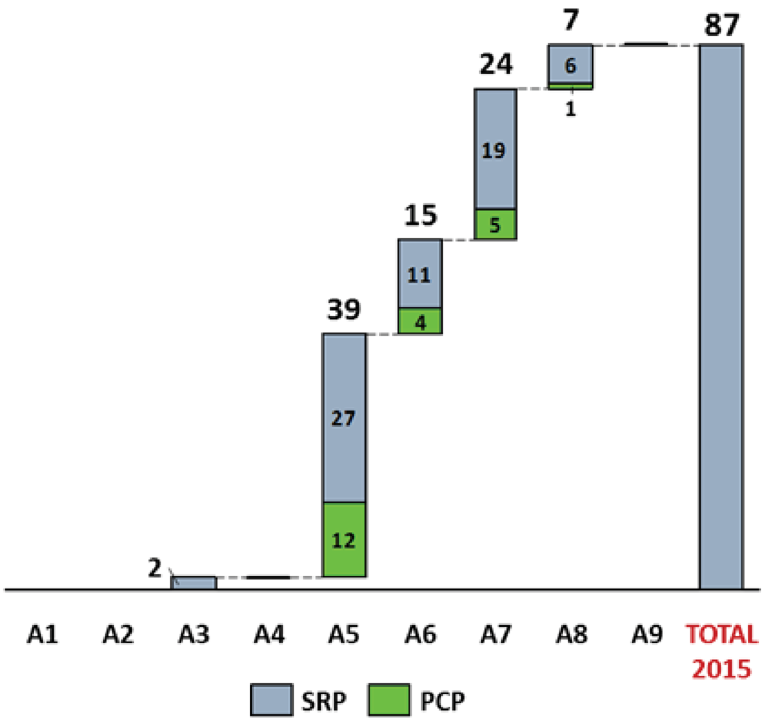

Figure 19: Total number of downhole pump failures for ALL REASONS after the occurrence of electrical breaks in 2015

However, out of the 87 total failures recorded in 2015, 52 of them were caused by sand reasons, as shown in Figure 20.

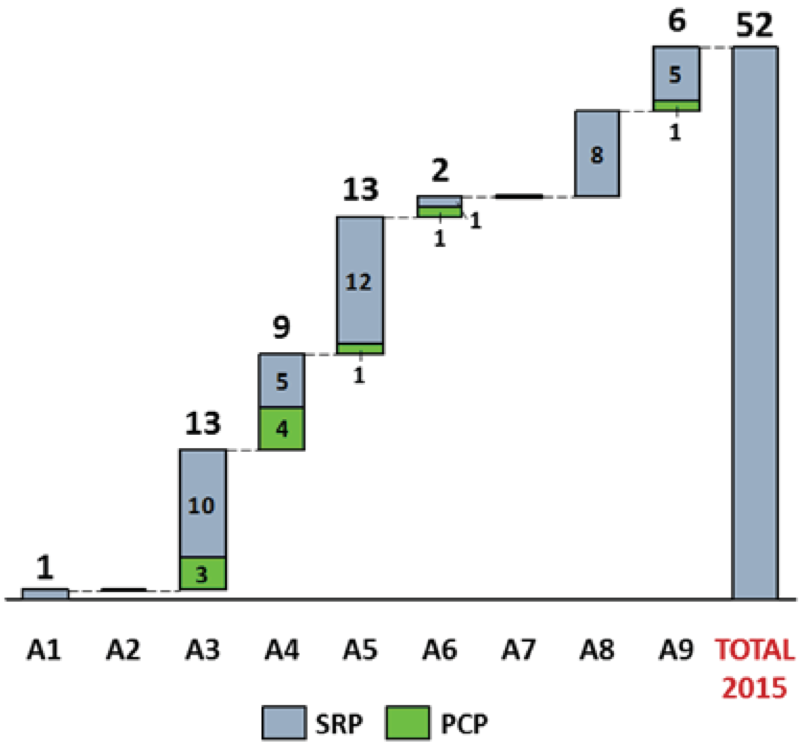

Figure 20: Total number of downhole pump failures for SAND REASONS after the occurrence of electrical breaks in 2015

5.6.1.3 Conclusions

- Most of the pump failures were on sucker rod pumps
- 47.5% of the total downhole pump failures recorded in 2014 within 4 days after an electrical break and 59.8% in 2015 were caused by sand reasons
- The total pump failures in 2015 was 87, which represents a 71% decrease compared to 2014 (299 pump failures)
- Electrical breaks should be avoided/fixed earlier because sand buildup causes an average of 53.7% of the pump failures which occur in the first 4 days for the time interval analyzed (2014-2015).

6 DOF approach to reduce losses

6.1 Assumptions and estimates

6.1.1 Weak wells, decreased flow, and watercut increase wells

The number of automated wells which recorded losses in each category (weak wells, decreased flow, and watercut increase) is derived by multiplying the actual production of all wells in each category for one year with the number of wells on company level, and dividing the result to the actual production of all wells on company level for one year.

The average time between 2 well tests, the average decline from production potential after a well test and the success rate of the corrective action after a well test are assumed by consulting with experts in the company.

6.1.2 Electrical breaks

Well downtime after transient faults and blackouts is an estimate based on the electrical breaks database for 2015. The reduction in production losses by implementing fault current indicators and remote start-up procedure are estimates based on pilot deployments and approximations. The number of fault current indicators used is an extrapolation from the number of indicators used in pilot deployments to the company level.

Losses of wells fitted with well automation is an estimate based on the number of automated wells relative to onshore company wells.

6.2 Remote monitoring with flowmeter to maximize equipment performance in ‘weak wells’

6.2.1 Current situation in the company

In 2015, the losses in OMV Petrom due to ‘weak wells’ totaled 97,886 tons of crude oil, or 21% of the total losses of the same year. Out of these, 39% took place in automated wells, or 38,176 tons. The number of automated wells which recorded losses in this category was 1,402.

The average decline from the production potential recorded during a well test in automated wells under the category ‘weak wells’ is 5%. The result is an average daily loss per well of 0.53 barrels of oil. Only the wells fitted with well automation are focused to loss management by a digital oilfield approach because of the real-time data communication requirement.

The average interval between two well tests in the company is 20 days. During this interval the production behavior of individual wells is not tracked. Once a well test is done and production deferments are reported, an investigation starts in order to bring the well back to its potential, which lasts an average of 3 days. In case of weak wells, in 70% of the cases production is restored back to its potential. Considering a linear cumulative production loss slope, an illustration of the process is presented in Figure 21.

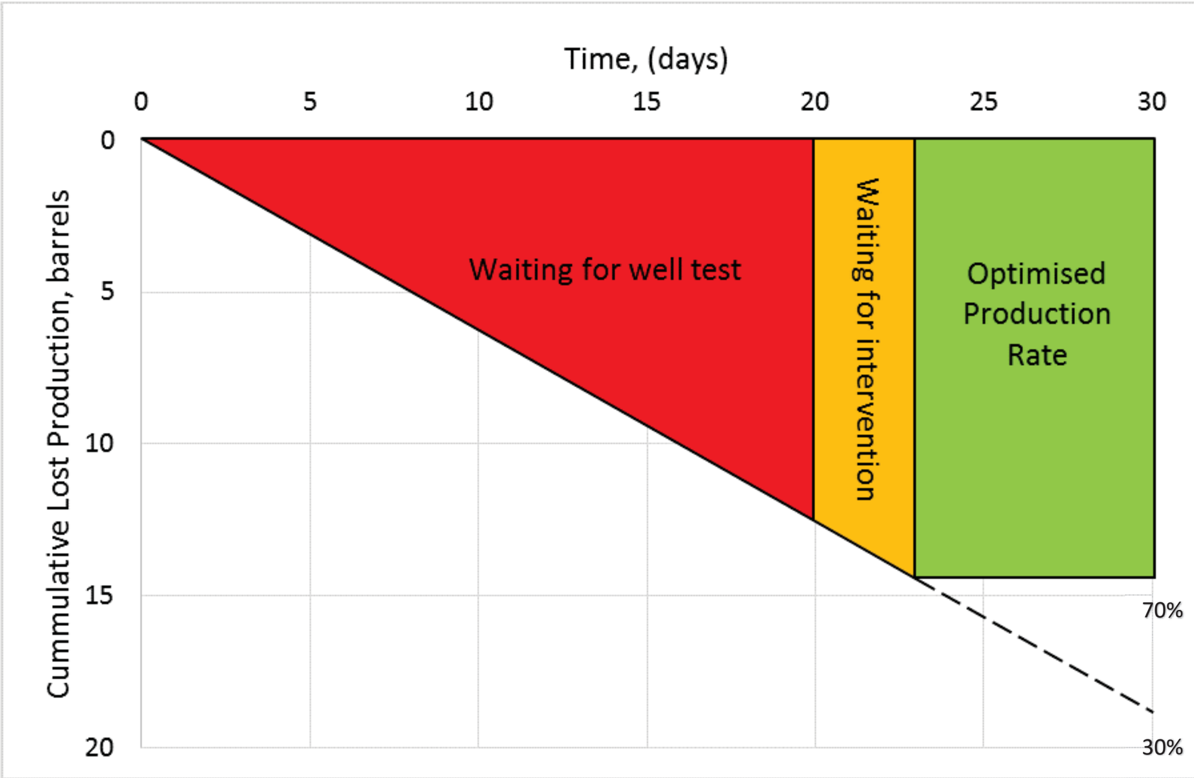

Figure 21: Loss profile of a weak well without flowmeter

In 2015, the average loss from the production potential of an automated well in the category 'weak wells' consists of 0.53 bbls/day, resulting in a loss of 14.49 bbls over 23 days.

Assuming the corrective action after the well test has success for a 'weak well' in 70% of the cases, there are 2 production scenarios: case 1, when the corrective action fails and the losses continue at the same rate for the rest of the month, and case 2, when production rate is optimized for the rest of the month. A weighed average of the 2 cases is presented in Table 3.

Table 3: Monthly losses of a weak well without flowmeter installed

Scenario	Probability of occurrence	Month interval (days) 1-23 losses (bbl)	Month interval (days) 24-30 losses (bbl)	Total monthly losses (bbl)	Total daily losses (bbl)
Case 1	30%	14.49	4.41	18.9	0.63
Case 2	70%	14.49	0	14.49	0.48
Average losses	-	14.49	1.32	15.90	**0.53**

6.2.2 Remote monitoring with flowmeter device

Turbine flowmeter

Turbine flowmeters provide an efficient way to accurately measure liquid and gas streams. The volumetric flow measurement is inferred based on the mechanical properties of the meter and the physical characteristics of the fluid being measured. A combination of a mechanical assembly and electronic components is used to measure flowrate.

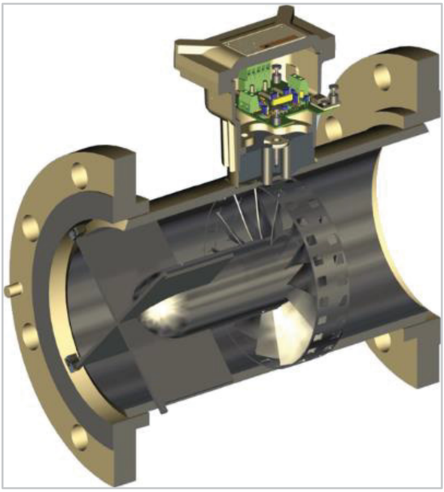

Figure 22: Turbine flowmeter typical design (Courtesy of the Emerson Process Management) [9]

An illustration of a typical turbine flowmeter is shown in Figure 22. The main components are a rotor with numerous blades, a free-running bearing system, a magnetic pickup coil, and the turbine meter housing. The fluid flow is acting on the rotor blades, causing them to move proportional to the fluid speed. As the rotor blade passes the magnetic pickup coil, a voltage pulse is produced, which corresponds to a certain volume of fluid. Because the cross-sectional area of the meter housing is known, the volumetric flowrate can be inferred. [9]

Installing a turbine flowmeter on each of the 1402 automated wells would allow real-time monitoring of the fluid flowrate and enable early action to reduce losses.

The same scenario presented in Figure 21 being applied to the same well which has a flowmeter installed, an illustration of the monthly cumulative production loss is illustrated in Figure 23.

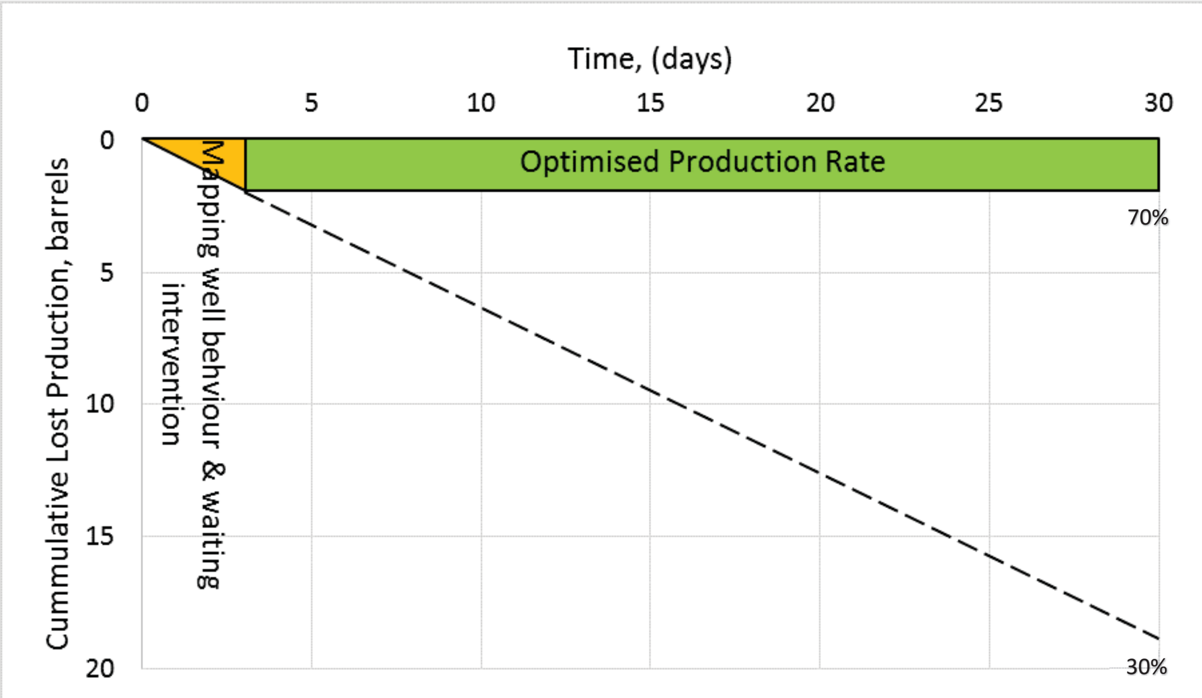

Figure 23: Loss profile of a weak well with flowmeter

Assuming the same success ratio in getting the well flow back to potential as in a weak well without flowmeter installed, there are two production scenarios after the well production behavior has been mapped and corrective action has been taken: case 1, occurring 30% of the times, when the corrective action fails and the losses continue at the same rate for the rest of the month, and case 2, occurring in 70% of the times, when production rate is optimized for the rest of the month. A weighed average of the 2 cases is presented in Table 4.

Table 4: Monthly losses of a weak well with flowmeter installed

Scenario	Probability of occurrence	Month interval (days) 1-3 losses (bbl)	Month interval (days) 4-30 losses (bbl)	Total monthly losses (bbl)	Total daily losses (bbl)
Case 1	30%	1.89	17.01	18.9	0.63
Case 2	70%	1.89	0	1.89	0.06
Average losses	-	1.89	5.1	6.99	**0.23**

6.2.3 Economic analysis

The economic analysis of this project was done for a period of 5 years, starting mid-2016. As a result the revenues due to incremental production and the OPEX for the first year were accounted as half the normal yearly level. The revenues and costs are calculated for a base case oil price of 60$/bbl and a sensitivity analysis has been performed for 3 revenue scenarios: 2015 – base case, +25% incremental production, and -25% incremental production, and for 3 oil price scenarios: 45, 60 and 75$/bbl.

The taxes considered for the analysis were a royalty tax of 4% of the oil production, a production tax of 0.63$/bbl, and a profit income tax of 16%.

Revenues

Having the year 2015 as a reference for production losses, the end result of using real-time monitoring combined with a flow metering device in 'weak wells' is a reduction of average production losses per well from 0.53 bbls to 0.23 bbls per day. This translates into 9 bbls of incremental production/month/well, or 108 bbls/year/well. At a crude oil price/ barrel of $60, the extra income/well/year is $5,137. Multiplied with the number of wells on which the flowmeter is installed, 1,402, the benefits are of $7,202,300 /year or €6,373,717/year.

Costs

The average cost of a turbine flowmeter for the wells under investigation is €7,000, multiplied with the number of wells, 1,402, the cost is €9,814,000. Installing each item costs €160, multiplied with 1,402, that is €224,320. Total CAPEX is presented in Table 5.

Table 5: CAPEX of turbine flowmeters in weak wells

Net Capital Costs	
Turbine flowmeters	€ (9,814,000)
Installation	€ (224,320)
Total Capital	**€ (10,038,320)**

The yearly OPEX of flowmeters for weak wells is presented in Table 6. A maintenance and calibration cost of 25€/month/well and an escalation of costs of 2% per year has been considered for the analysis.

Table 6: OPEX of turbine flowmeters in weak wells

Operating and Maintenance Costs	Year 0	Year 1	Year 2	Year 3	Year 4
Maintenance, calibration	€ (210,300)	€ (420,600)	€ (420,600)	€ (420,600)	€ (420,600)
Escalation of Costs	-	€ 8,412	€ 16,992	€ 25,744	€ 34,671
Total Costs	**€ 210,300**	**€ 429,012**	**€ 437,592**	**€ 446,344**	**€ 455,271**

The business case results of installing flowmeters on all 1,402 automated wells recording losses in the 'weak wells' category are presented in Table 7. The NPV of the cash flow is calculated for a period of 5 years and the discount rate is set at 15%.

Table 7: Business case results of flowmeters in weak wells

NPV of Cash Flow	**€ 9,877,346**
IRR	**75%**
Profitability Index	**2.40**
Discounted Payback (15%)	2 Years 5 Months

The CAPEX, OPEX, and revenue are presented as they develop throughout the years in Figure 24.

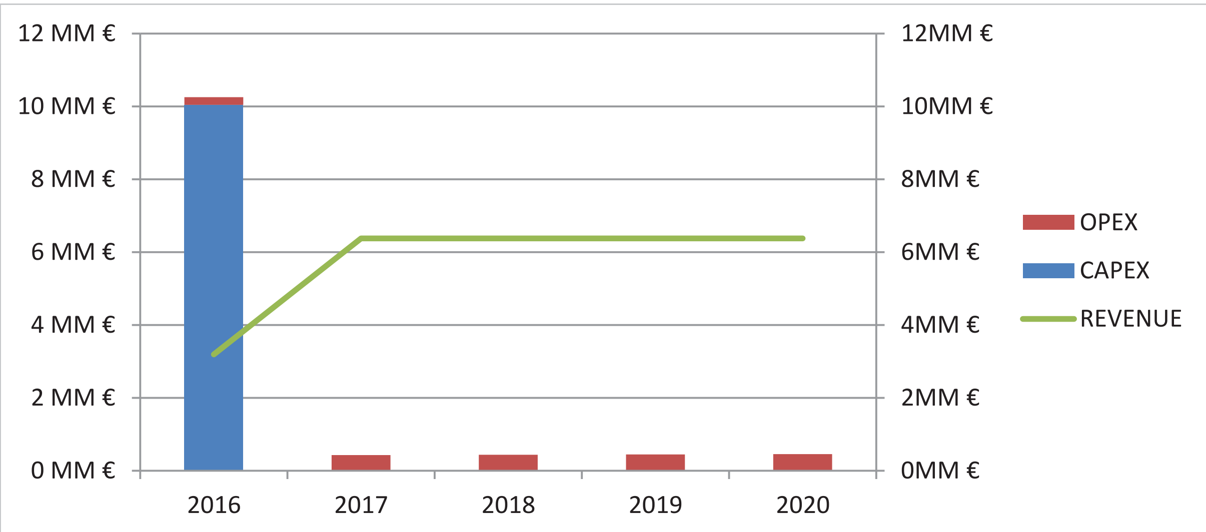

Figure 24: CAPEX, OPEX, and revenue in weak wells base case for 60$/bbl

Sensitivity analysis

The variables with the highest degree of uncertainty of the project are the incremental production which can be gained by the DOF approach and the oil price. In order to account for them a sensitivity analysis has been developed for 3 revenue scenarios: 2015 – base case,

+25% incremental production, and -25% incremental production, and for 3 oil price scenarios: 45, 60 and 75$/bbl.

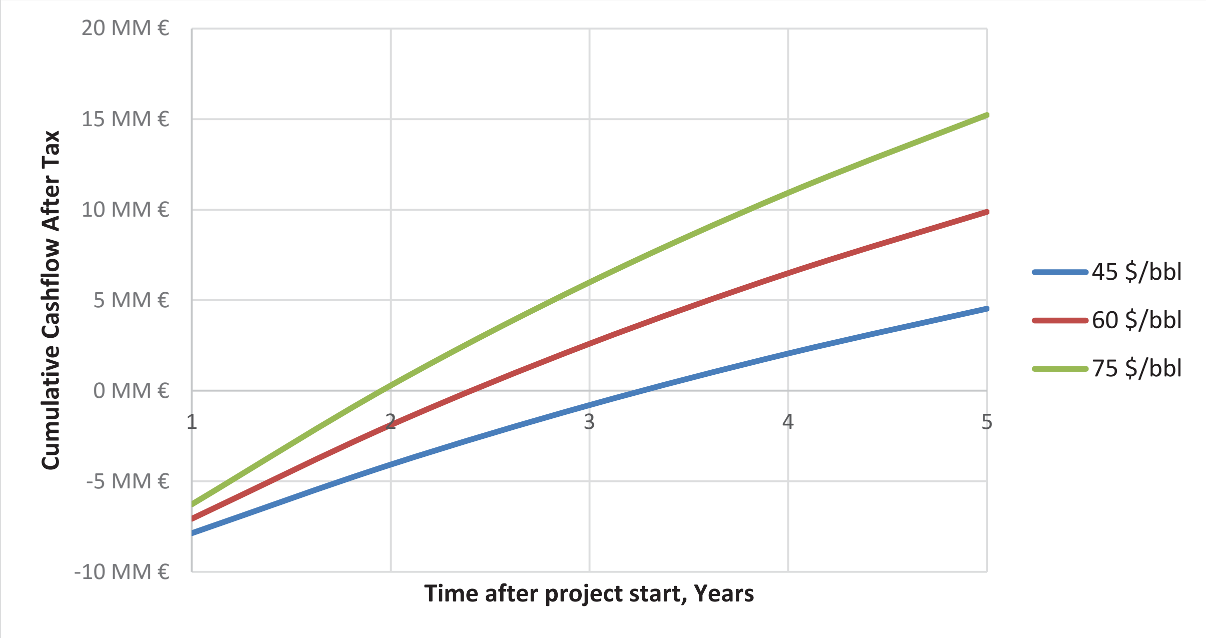

Figure 25: Cumulative cashflow weak wells base incremental production case

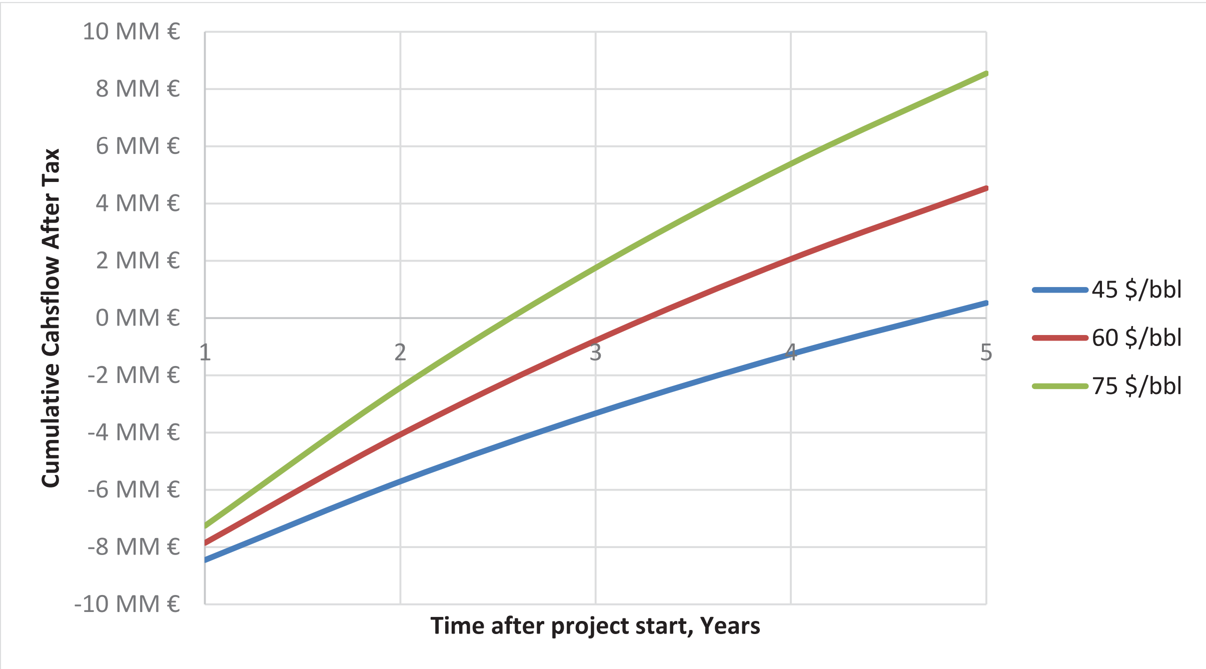

Figure 26: Cumulative cashflow weak wells -25% incremental production case

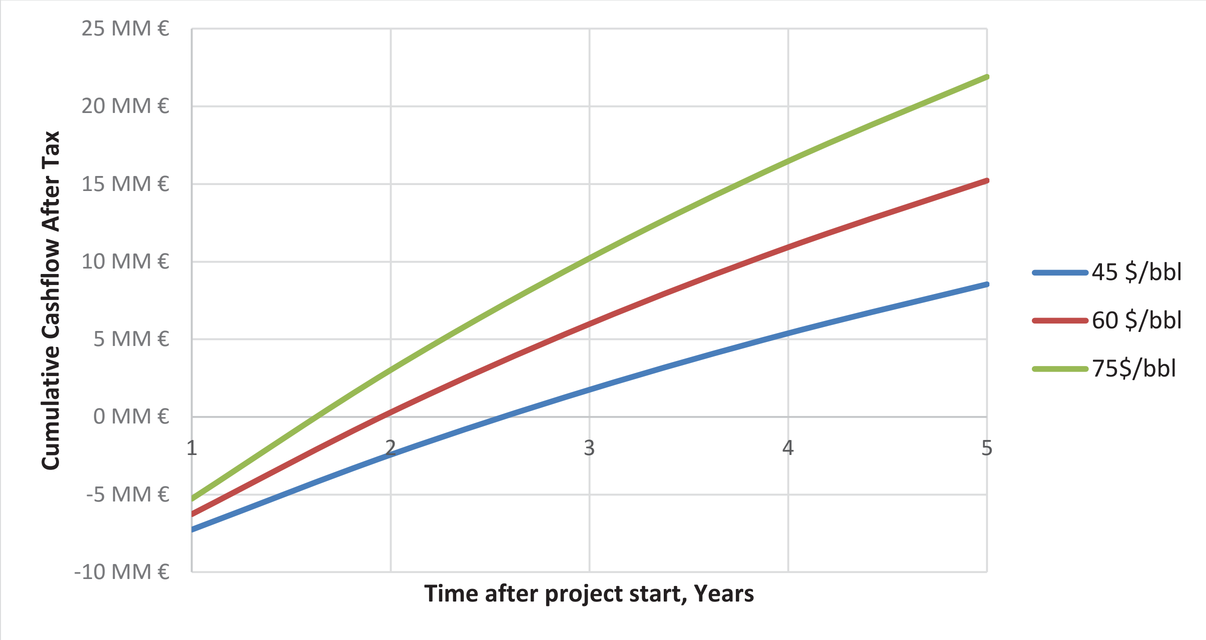

Figure 27: Cumulative cashflow weak wells +25% incremental production case

As presented in Figure 25, Figure 26, and Figure 27, the project is economical in any of the analyzed scenarios.

6.3 Remote monitoring with flowmeter to optimize reservoir management in ‘decreased flow’ wells

6.3.1 Current situation in the company

In 2015, the losses in OMV Petrom due to ‘decreased flow’ totaled 58,372 tons of crude oil, or 13% of the total losses of the same year. Out of these, 34% took place in automated wells, or 19,846 tons. The number of automated wells which recorded losses in this category was 561.

The average decline from the production potential recorded during a well test in automated wells under the category ‘weak wells’ is 7%. The result is an average daily loss per well of 0.69 barrels of oil.

Once a well test is done and production deferments are reported, an investigation starts in order to bring the well back to its potential, which lasts an average of 3 days. In case of ‘decreased flow’ wells, in 40% of the cases production is restored back to its potential. Considering a linear cumulative production loss slope, an illustration of the process is presented in Figure 28.

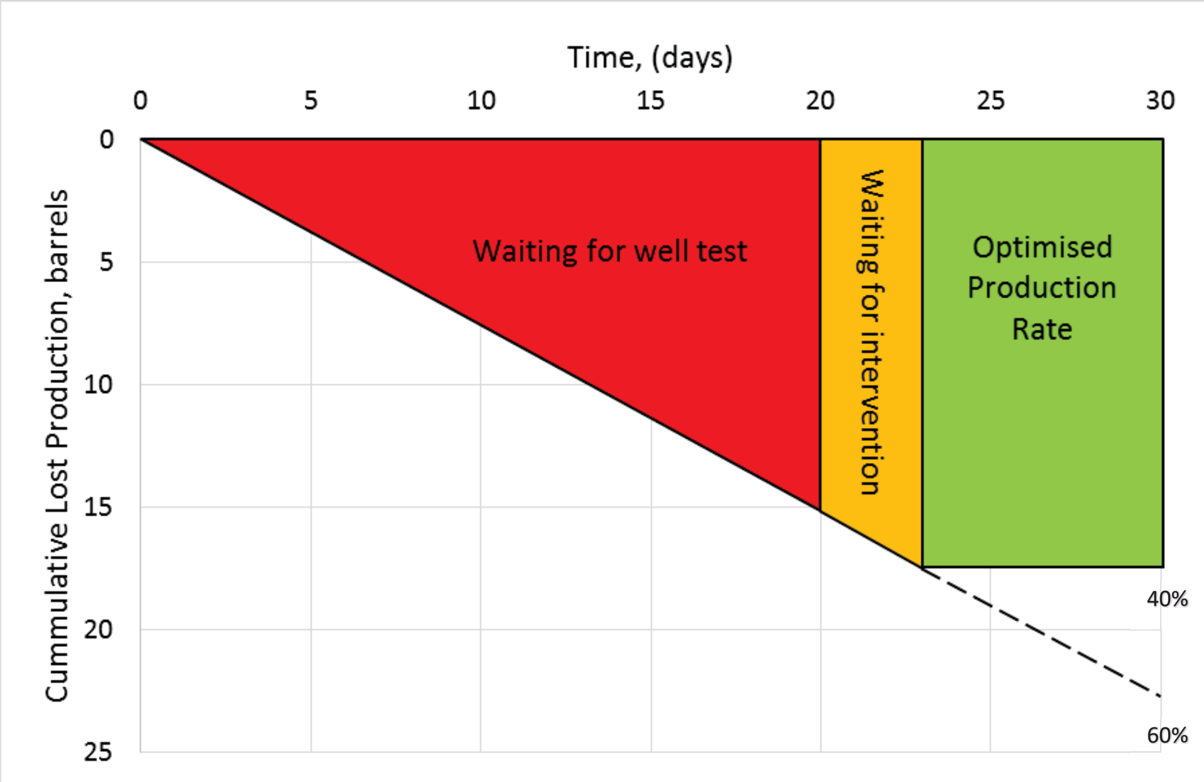

Figure 28: Loss profile of a decreased flow well without flowmeter

In 2015, the average loss from the production potential of an automated well in the category 'decreased flow' consists of 0.69 bbls/day, resulting in a loss of 17.48 bbls over 23 days.

Assuming the corrective action after a well test has success for a 'decreased flow' well in 40% of the cases, there are 2 production scenarios: case 1, when the corrective action fails and the losses continue at the same rate for the rest of the month, and case 2, when production rate is optimized for the rest of the month. A weighed average of the 2 cases is presented in Table 8.

Table 8: Monthly losses of a decreased flow well without flowmeter installed

Scenario	Probability of occurrence	Month interval (days) 1-23 losses (bbl)	Month interval (days) 24-30 losses (bbl)	Total monthly losses (bbl)	Total daily losses (bbl)
Case 1	60%	17.48	5.32	22.8	0.76
Case 2	40%	17.48	0	17.48	0.58
Average losses	-	17.48	3.19	20.70	**0.69**

6.3.2 Remote monitoring with flowmeter device

The same scenario being applied to a ‘decreased flow well’ which has a turbine flowmeter installed at the wellhead, an illustration of the monthly cumulative production loss is illustrated in Figure 29.

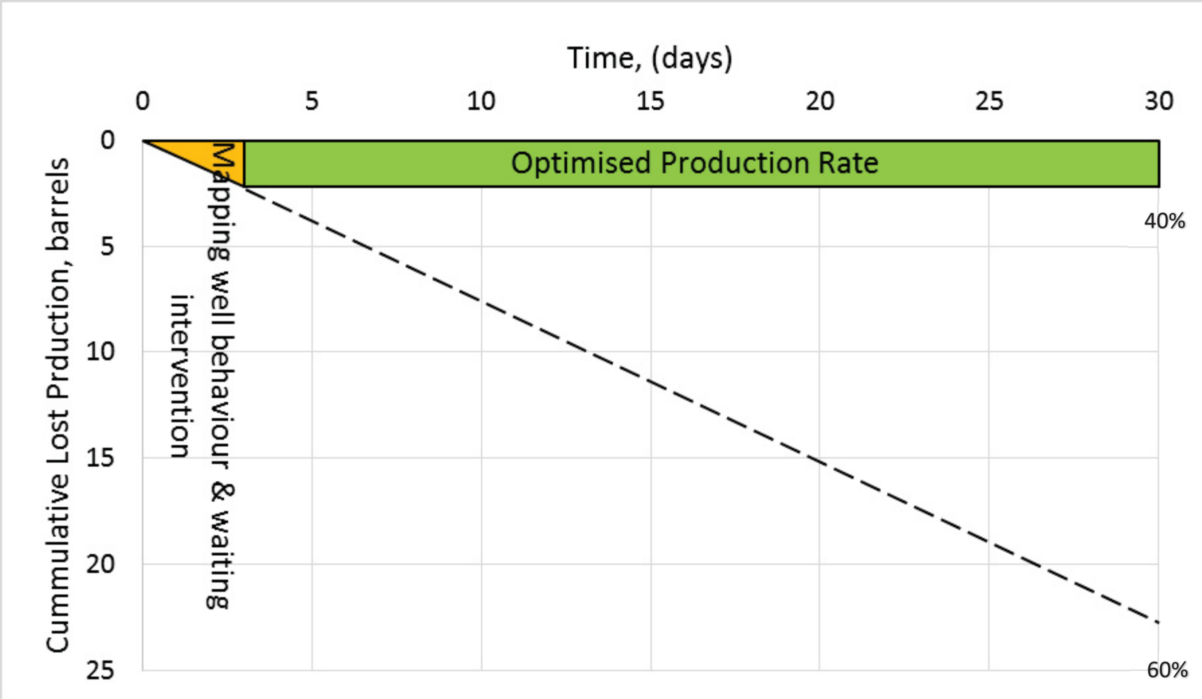

Figure 29: Loss profile of a decreased flow well with flowmeter

Assuming the same success ratio of getting the well flow back to potential as in a decreased flow well without flowmeter installed, there are two production scenarios after the well behavior has been mapped and corrective action has been taken (intervention): case 1, occurring 60% of the times, when the corrective action fails and the losses continue at the same rate for the rest of the month, and case 2, occurring 40% of the times, when production rate is optimized for the rest of the month. A weighed average of the 2 cases is presented in Table 9.

Table 9: Monthly losses of a decreased flow well with flowmeter installed

Scenario	Probability of occurrence	Month interval (days) 1-3 losses (bbl)	Month interval (days) 4-30 losses (bbl)	Total monthly losses (bbl)	Total daily losses (bbl)
Case 1	60%	2.28	20.52	22.8	0.76
Case 2	40%	2.28	0	2.28	0.06
Average losses	-	2.28	12.31	14.59	**0.48**

6.3.3 Economic analysis

The economic analysis of this project was done for a period of 5 years, starting mid-2016. As a result the incremental production and the OPEX for the first year were accounted as half the normal yearly level. The revenues and costs are calculated for a base case oil price of 60$/bbl and a sensitivity analysis has been performed for 3 revenue scenarios: 2015 – base case, +25% incremental production, and -25% incremental production, and for 3 oil price scenarios: 45, 60 and 75$/bbl.

The taxes considered for the analysis were a royalty tax of 4% of the oil production, a production tax of 0.63$/bbl, and a profit income tax of 16%.

Revenues

Having the year 2015 as a reference for production losses, the result of using real-time monitoring combined with a flow metering device in ‘decreased flow wells’ is a reduction of average production losses per well from 0.69 bbls to 0.48 bbls per day. This translates into 6.3 bbls of incremental production/month/well, or 75.6 bbls/year/well. At a crude oil price/ barrel of $60, the extra income/well/year is $3,606. Multiplied with the number of wells on which the flowmeter is installed, 561, the benefits would be of $2,022,719/year or €1,785,277/year.

Costs

The average cost of a turbine flowmeter is €7,000, multiplied with the number of wells under analysis, 561, the cost would be €3,927,000. Installing each item at the wellhead costs €160, multiplied with 561, that is €89,760. Total CAPEX is presented in Table 10.

Table 10: CAPEX of turbine flowmeters in decreased flow wells

Net Capital Costs	
Turbine flowmeters	€ (3,927,000)
Installation	€ (89,760)
Total Capital	**€ (4,016,760)**

The yearly OPEX of flowmeters for decreased flow wells is presented in Table 11. A maintenance and calibration cost of €25/month/well and an escalation of costs of 2% per year have been considered for the analysis.

Table 11: OPEX of turbine flowmeters in decreased flow wells

Operating and Maintenance Costs	Year 0	Year 1	Year 2	Year 3	Year 4
Maintenance, calibration	€ (84,150)	€ (168,300)	€ (168,300)	€ (168,300)	€ (168,300)
Escalation of Costs	-	€ 3,366	€ 6,799	€ 10,301	€ 13,873
Total Costs	**€ 84,150**	**€ 171,666**	**€ 175,099**	**€ 178,601**	**€ 182,173**

The business case results of installing flowmeters on all 561 automated wells recording losses in the 'decreased flow' category are presented in Table 12 . The NPV of the cash flow is calculated for a period of 5 years and the discount rate is set at 15%.

Table 12: Business case results of flowmeters in decreased flow wells

NPV of Cash Flow	**€ 1,385,390**
IRR	**35%**
Profitability Index	**1.43**
Discounted Payback (15%)	3 Years 7 Months

The CAPEX, OPEX, and Revenue are shown as they develop throughout the years in Figure 30.

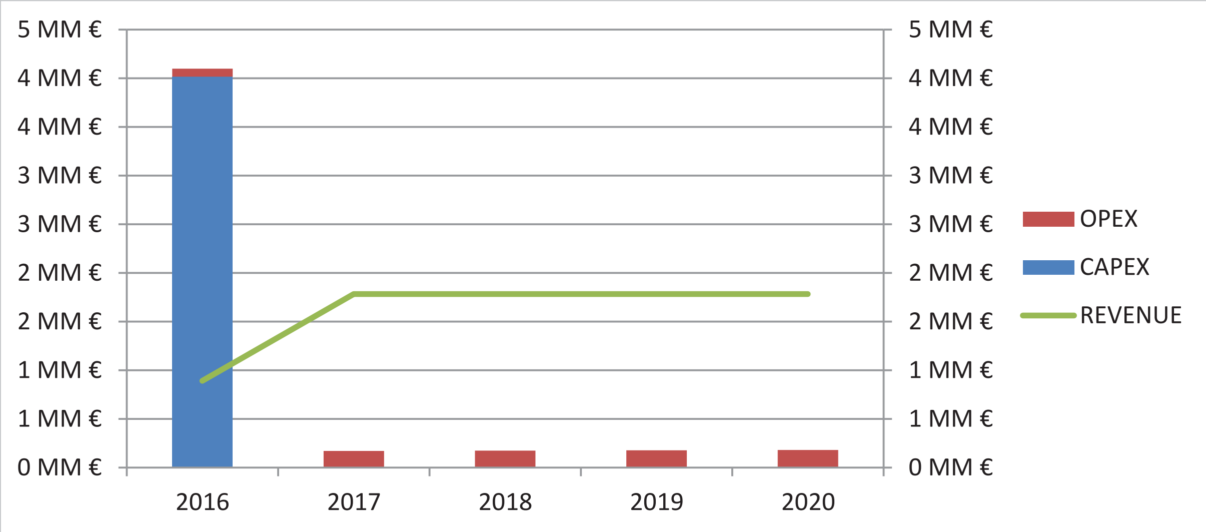

Figure 30: CAPEX, OPEX, and Revenue in decreased flow wells base case 60$/bbl

Sensitivity analysis

Because the incremental production which can be achieved by the DOF approach is a variable that can change from the reference value calculated for 2015 and because the oil price is also uncertain, a sensitivity analysis was developed for the project for 3 revenue scenarios: 2015 – base case, +25% incremental production, and -25% incremental production, and for 3 oil price scenarios: 45, 60 and 75$/bbl.

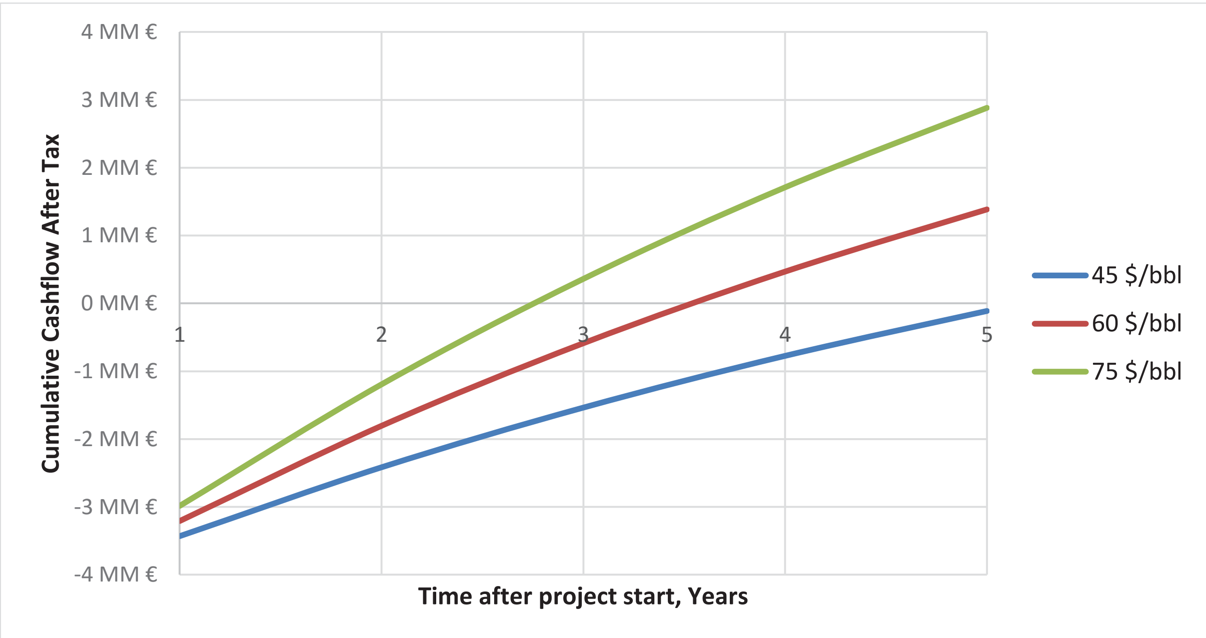

Figure 31: Cumulative cashflow decreased flow wells base incremental production case

As shown in Figure 31 , the project is slightly uneconomic for a payback period limited to 5 years and a 45$/bbl oil price base incremental production case scenario. For the other two oil price scenarios the project hits breakeven in-time.

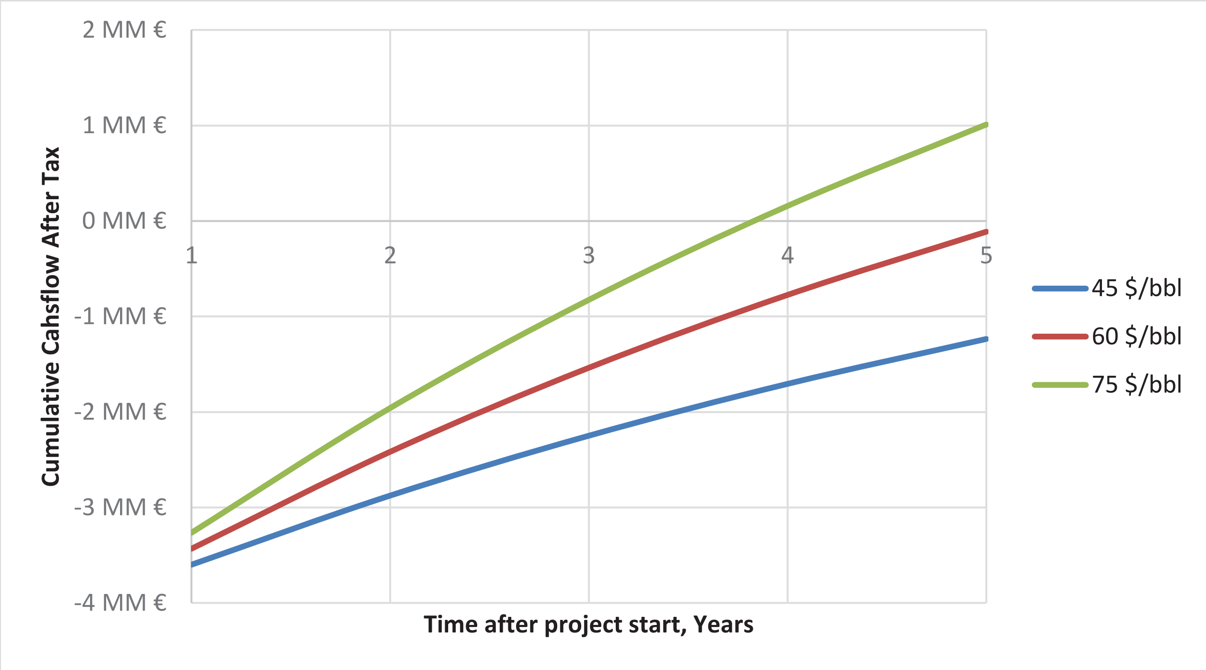

Figure 32: Cumulative cashflow decreased flow wells -25% incremental production case

In case the incremental production in weak wells after DOF approach decreases by 25%, only the 75$/bbl oil price scenario makes the project attractive, as illustrated in Figure 32.

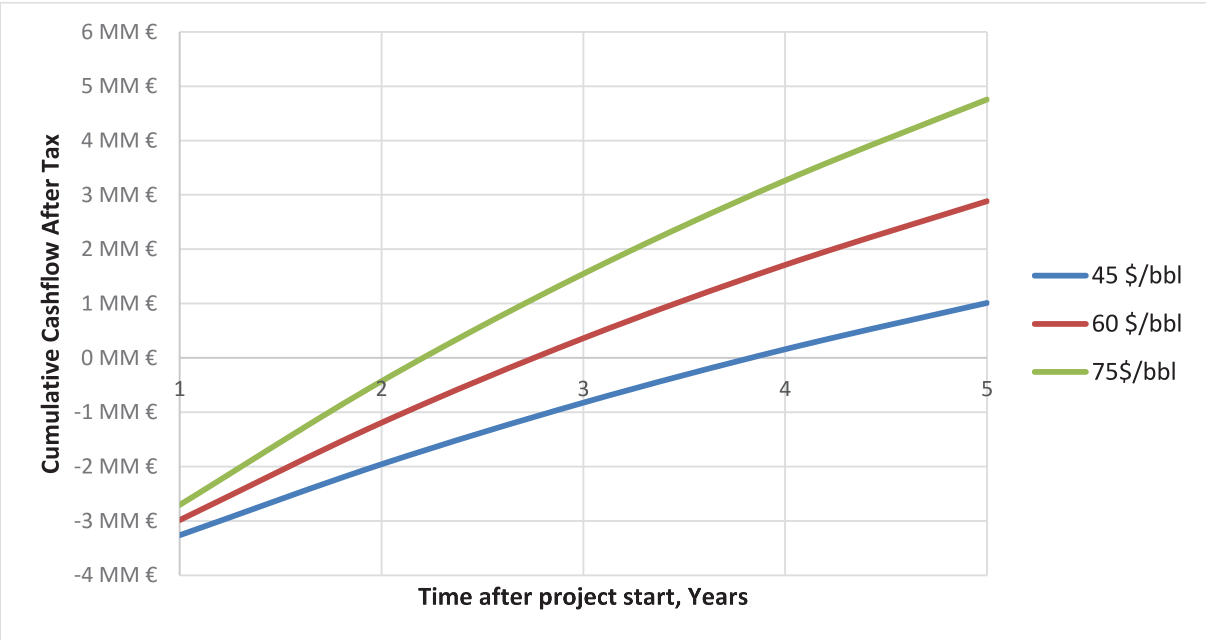

Figure 33: Cumulative cashflow decreased flow wells +25% incremental production case

Figure 33 shows that in case the incremental production increases by 25%, every scenario is economic within the set boundaries.

6.4 Remote monitoring with flowmeter and watercut sensor in ‘watercut increase’ wells

6.4.1 Current situation in the company

In order to be able to reduce the watercut, oilfield operators need to distinguish that there are two separate categories of water production:

- The first category occurs later in the life of a waterflood, when water is co-produced with oil due to the fractional flow characteristics in reservoir porous rock. In this case, to reduce the water production, the oil production must be reduced similarly.

- The second category of water production is in direct competition with the oil and it has a different route of flowing into the wellbore than the hydrocarbons. Such sources could be crossflow, water coning, or high permeability water channels. For this category, a reduction in water production would frequently lead to better pressure drawdowns with consequent rise in oil production rates.

Increasing pumping speed is not the optimum pumping level for achieving maximum oil production and/or following possible oil cycles created by the reservoir dynamics. By surveilling real-time a well’s watercut with a flowmeter and watercut sensor installed at the surface, the well can be optimized automatically by writing an algorithm to search for the maximum oil cut. This can be done in wells fitted with WA by sending a dynamic signal to the prime movers controller and measuring the response.

In 2015, the losses in OMV Petrom due to ‘watercut increase’ totaled 111,710 tons of crude oil, or 24% of the total losses of the same year. Out of these, 45% took place in automated wells, or 50,270 tons. The number of automated wells which recorded losses in this category was 1213.

The average decline from the production potential recorded during a well test in automated wells under the category ‘watercut increase’ is 8%.The result is an average daily loss per well of 0.81 barrels of oil.

After a well test in which a well reports losses due to watercut increase, an average period of 3 days passes until an intervention or corrective action is applied to the well. Considering an average success rate of bringing the production back to its potential of 20% and a linear cumulative production loss slope, an illustration of the process is presented in Figure 34.

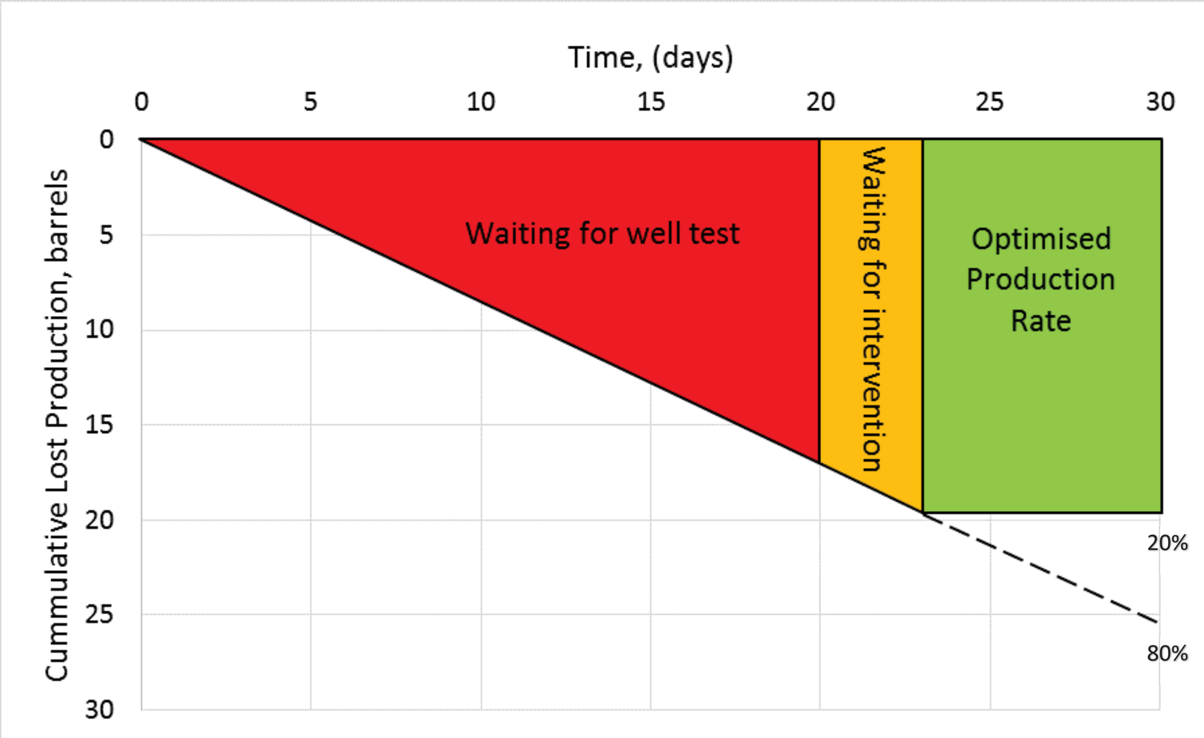

Figure 34: Loss profile of a watercut increase well without flowmeter

In 2015, the average loss from the production potential of an automated well in the category ‘watercut increase’ consists of 0.81 bbls/day, resulting in a loss of 19.55 bbls over 23 days.

Assuming the corrective action or intervention has success for a ‘watercut increase’ well in 20% of the cases, there are 2 production scenarios: case 1, when the corrective action fails and the losses continue at the same rate for the rest of the month, and case 2, when production rate is optimized for the rest of the month. A weighed average of the 2 cases is presented in Table 13.

Table 13: Monthly losses of a watercut increase well without flowmeter installed

Scenario	Probability of occurrence	Month interval (days) 1-23 losses (bbl)	Month interval (days) 24-30 losses (bbl)	Total monthly losses (bbl)	Total daily losses (bbl)
Case 1	80%	19.55	5.95	25.5	0.85
Case 2	20%	19.55	0	19.55	0.65
Average losses	-	19.55	4.76	24.30	**0.81**

6.4.2 Remote monitoring with flowmeter and watercut sensor

A turbine flowmeter can be used in combination with a watercut sensor in order to allow flow rate optimization in the wells. As the flowmeter has already been described in chapter 6.2.2, following is a description of the watercut sensor to be used.

Watercut sensor

A watercut sensor operates based on the near-infrared (NIR) absorption spectroscopy. The functioning principle relies on measuring key wavelengths in the NIR spectrum to distinguish between water, gas, and liquid hydrocarbons in an emulsion. The meter is insensitive to water salinity and can handle free gas.

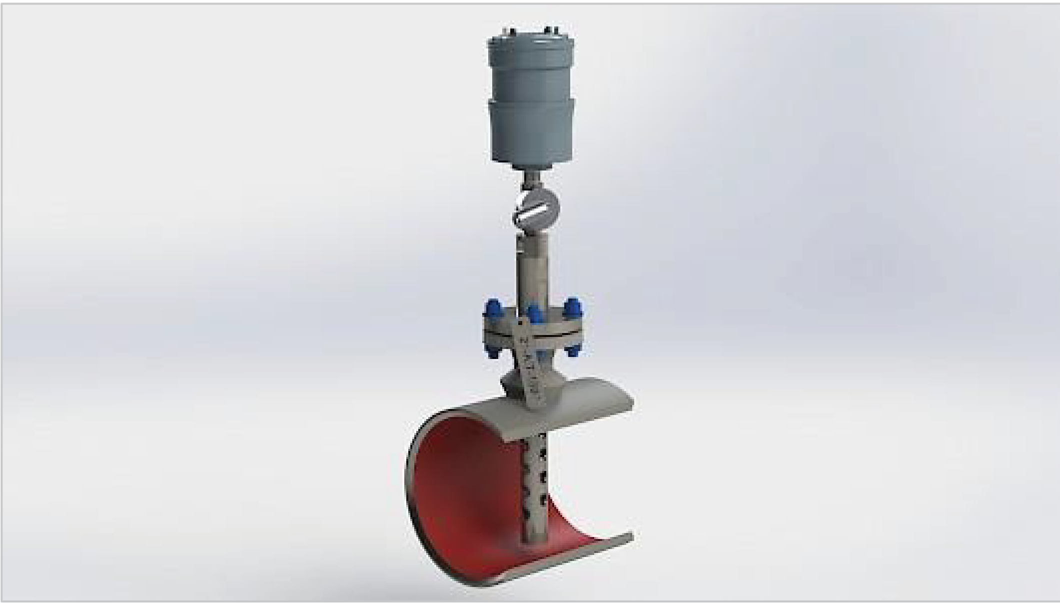

Figure 35: Illustration of a watercut sensor [10]

Installing watercut sensors in combination with turbine flowmeters on all the 1213 automated wells would allow monitoring multiphase flow in wells affected by watercut increase and proactive action to bring the flowrates back to potential.

The same scenario illustrated in Figure 34 being applied to a 'watercut increase' well which has a flowmeter and watercut sensor installed, an illustration of the monthly cumulative production losses is illustrated in Figure 36.

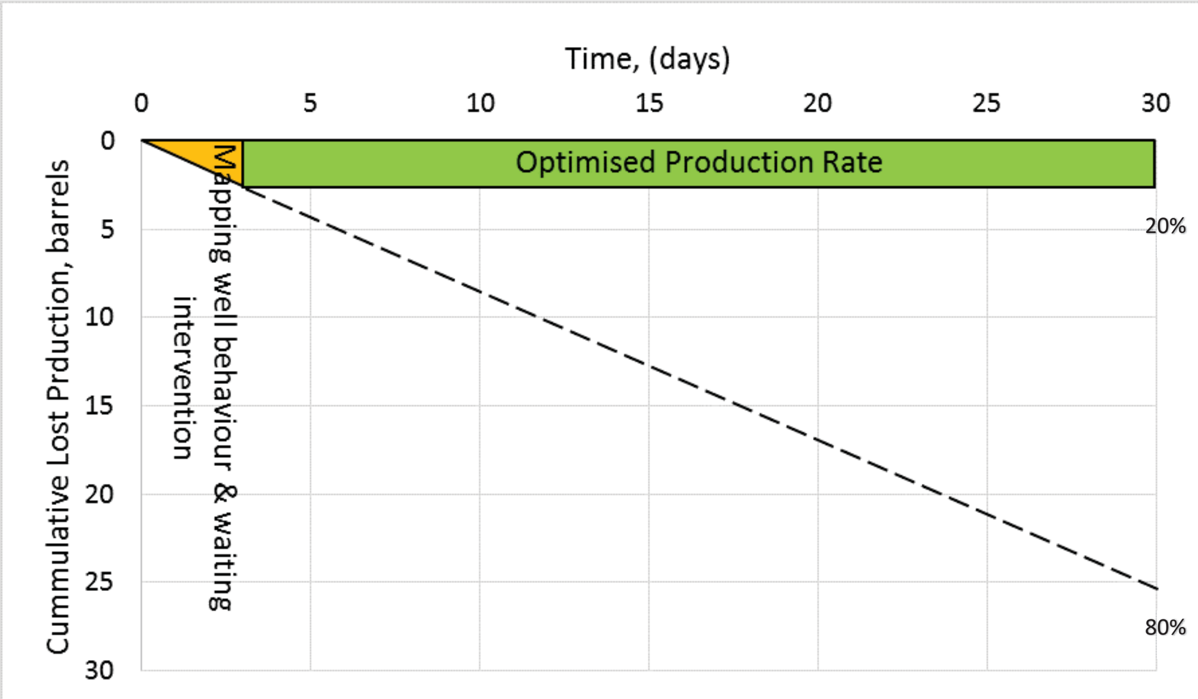

Figure 36: Loss profile of a watercut increase well with flowmeter

Assuming the same success ratio of getting the well flow back to potential as in a watercut increase well without multiphase flow metering installed, there are two production scenarios after the well behavior has been mapped and corrective action has been taken: case 1, occurring 80% of the times, when the corrective action fails and the losses continue at the same rate for the rest of the month, and case 2, occurring 20% of the times, when production rate is optimized for the rest of the month. A weighed average of the 2 cases is presented in Table 14.

Table 14: Monthly losses of a watercut increase well with flowmeter installed

Scenario	Probability of occurrence	Month interval (days) 1-3 losses (bbl)	Month interval (days) 4-30 losses (bbl)	Total monthly losses (bbl)	Total daily losses (bbl)
Case 1	80%	2.55	22.95	25.5	0.85
Case 2	20%	2.55	0	2.55	0.09
Average losses	-	2.55	18.36	20.91	**0.69**

6.4.3 Economic analysis

The economic analysis of this project was done for a period of 5 years, starting mid-2016. As a result the incremental production and the OPEX for the first year were accounted as half the normal yearly level. The revenues and costs are calculated for a base case oil price of 60$/bbl and a sensitivity analysis has been performed for 3 revenue scenarios: 2015 – base case, +25% incremental production, and -25% incremental production, and for 3 oil price scenarios: 45, 60 and 75$/bbl.

The taxes considered for the analysis were a royalty tax of 4% of the oil production, a production tax of 0.63$/bbl, and a profit income tax of 16%.

Revenues

The outcome of using real-time monitoring combined with a flow metering device in 'watercut increase' wells is a reduction of average production losses per well from 0.81 bbls to 0.69 bbls per day. This translates into 3.6 bbls of incremental production/month/well, or 43.2 bbls/year/well. At a crude oil price/bbl of $60, the extra income/well/year is $2,055. Multiplied with the number of wells on which the flowmeter is installed, 1213, the benefits would be of $2,492,551/year or €2,205,797/year having the year 2015 as a reference for production losses.

Costs

The average cost of a turbine flowmeter for the wells under investigation is €7,000, multiplied with the number of wells, 1,213, the cost is €8,491,000. A watercut sensor costs an average of €10,000 and multiplied with 1,213, the cost is €12,130,000. Installing both devices at the wellhead costs €340, multiplied with 1213 that is €291,120. Total CAPEX is presented in Table 15.

Table 15: CAPEX of flowmeters and watercut sensors in watercut increase wells

Net Capital Costs	
Turbine flowmeters	€ (8,491,000)
Installation	€ (194,080)
Watercut sensors	€ (12,130,000)
Installation	€ (97,040)
Total Capital	**€ (20,912,120)**

The yearly operating and maintenance costs of flowmeters and watercut sensors for watercut increase wells is presented in Table 16. A maintenance and calibration cost of €50/month/well and an escalation of costs of 2% per year have been considered for the analysis.

Table 16: OPEX of turbine flowmeters and watercut sensors watercut increase wells

Operating and Maintenance Costs	Year 0	Year 1	Year 2	Year 3	Year 4
Maintenance, calibration	€ (363,900)	€ (727,800)	€ (727,800)	€ (727,800)	€ (727,800)
Escalation of Costs	-	€ (14,556)	€ (29,403)	€ (44,547)	€ (59,994)
Total Costs	**€ (363,900)**	**€ (742,356)**	**€ (757,203)**	**€ (772,347)**	**€ (787,794)**

The business case results of installing flowmeters and watercut sensors on all 1213 automated wells recording losses in the 'watercut increase' wells category are presented in Table 17. The NPV of the cash flow is calculated for a period of 5 years and the discount rate is set at 15%.

Table 17: Business case results of flowmeters and watercut sensors in watercut increase wells

NPV of Cash Flow	**€ -(16,051,954)**
IRR	**-36.5%**
Profitability Index	**0.20**
Discounted Payback (15%)	17 Years

The CAPEX, OPEX, and Revenue of the project for a 60$/bbl oil price and 2015 reference production losses are illustrated in Figure 37.

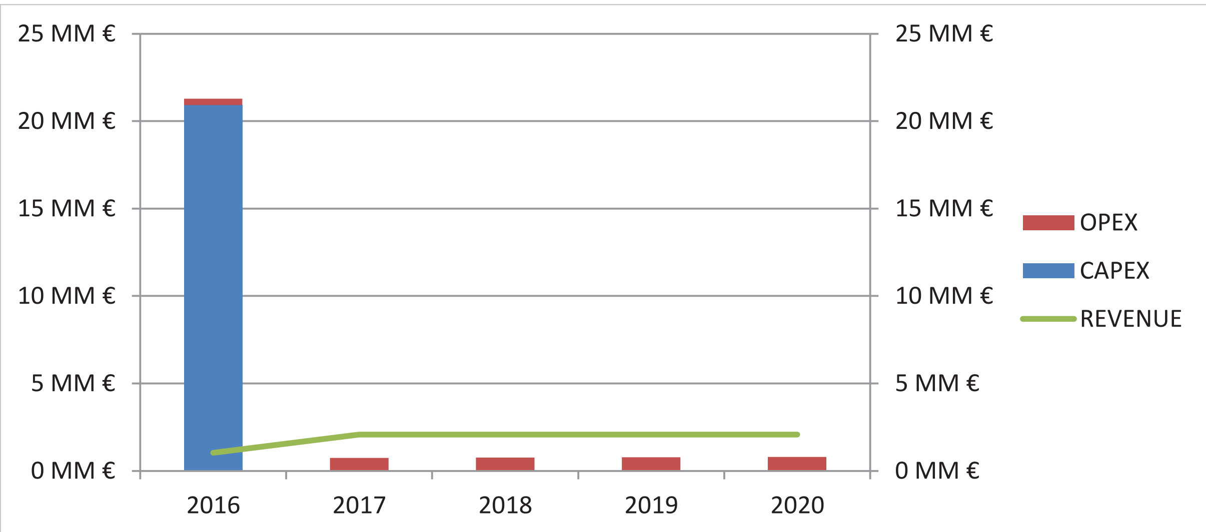

Figure 37: CAPEX, OPEX, and Revenue in watercut increase wells base case 60$/bbl

Sensitivity analysis

Because the incremental production which can be achieved by the DOF approach is a variable that can change from the reference value calculated for 2015 and because the oil price is also uncertain, a sensitivity analysis was developed for the project for 3 revenue scenarios: 2015 – base case, +25% incremental production, and -25% incremental production, and for 3 oil price scenarios: 45, 60 and 75$/bbl.

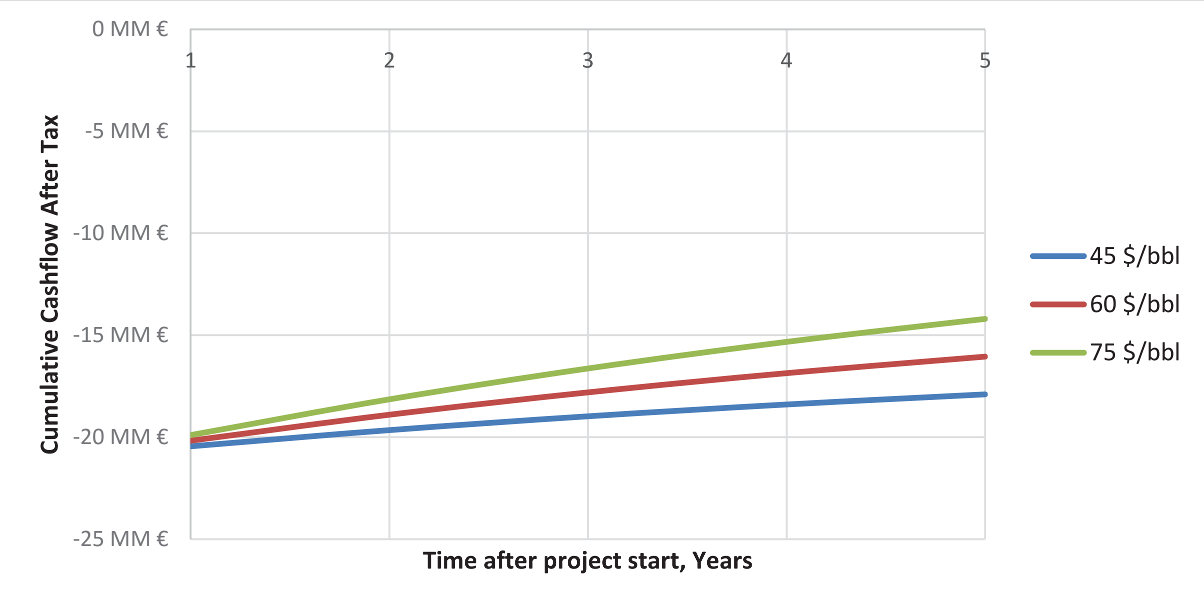

Figure 38: Cumulative cashflow watercut increase wells base incremental production case

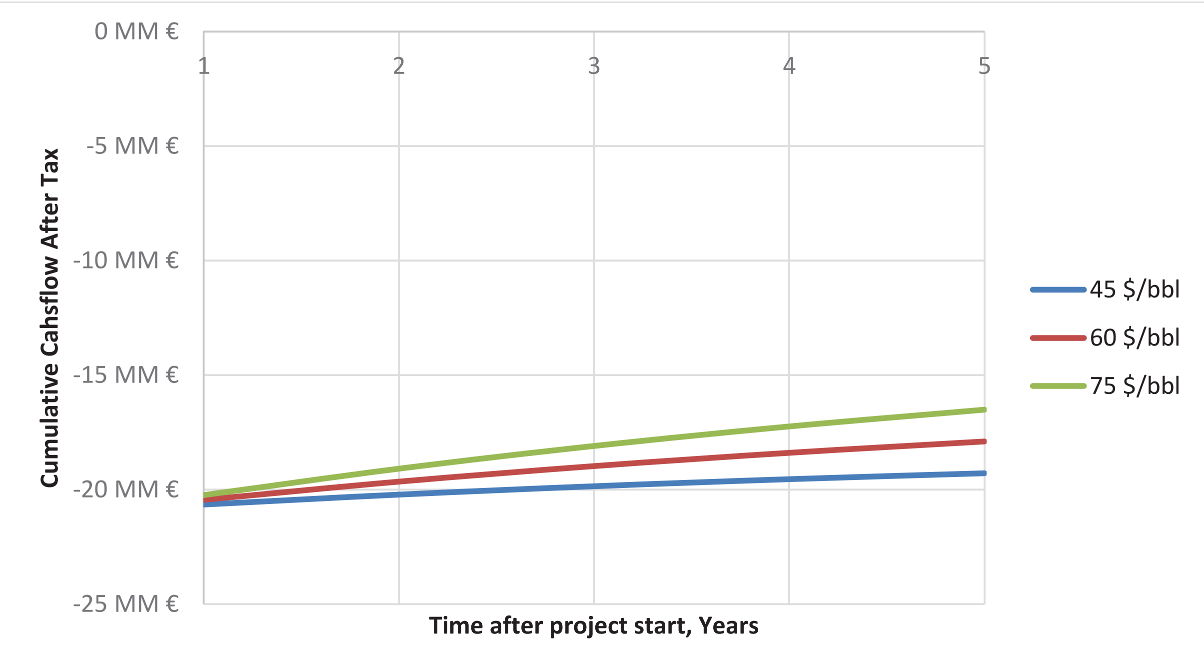

Figure 39: Cumulative cashflow watercut increase wells -25% incremental production case

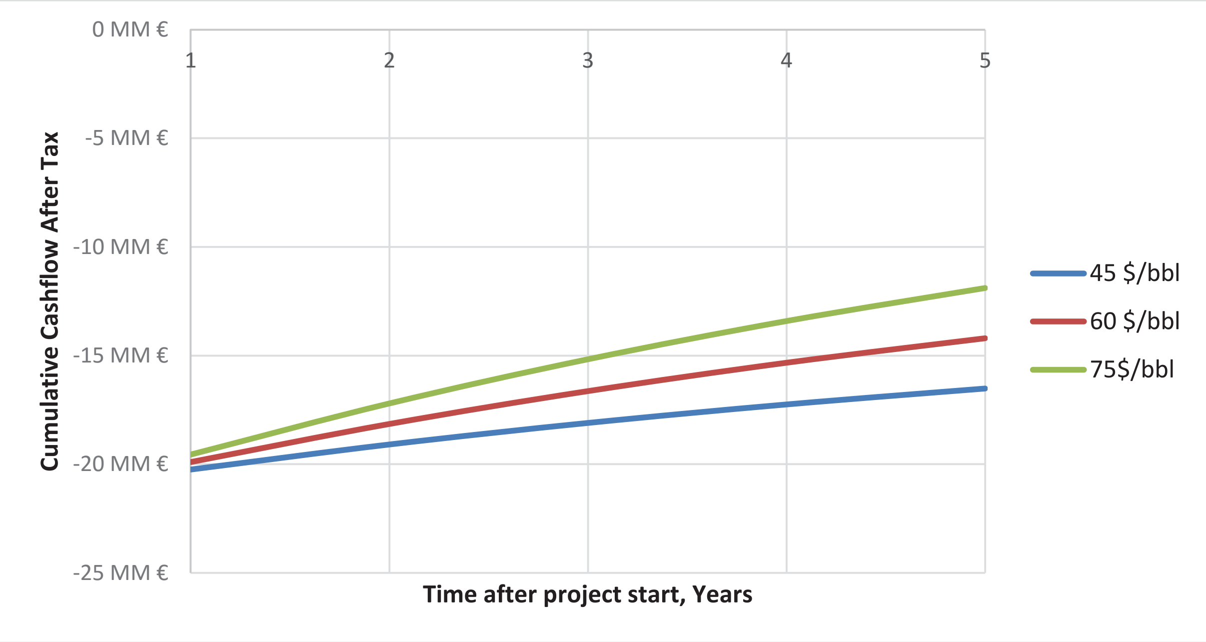

Figure 40: Cumulative cashflow watercut increase wells +25% incremental production case

As shown in Figure 38, Figure 39, and Figure 40, the project is highly uneconomical for any of the analyzed scenarios.

The maximum investment that would be paid-off in 5 years under base case conditions and 60$/bbl oil price would be a total CAPEX of €5,931,570 with a yearly OPEX of €363,900. That is equivalent to a capital expenditure of €4810/well, which makes the installation of any flow monitoring device unfeasible. For the investment to be paid off in 5 years the benefits due to incremental production should be of €6,990,500/year, or 3.2 times higher.

6.5 Electrical breaks

6.5.1 Types of electrical breaks in power lines

Electrical breaks represent a loss of the electrical power to an area, for a short-term or a long-term. Some of the reasons for the breaks can be damage at power stations or at electric transmission lines, or short-circuits.

There are more types of electrical breaks, depending on their duration and effect.

- A *blackout* involves complete loss of power to an area and has the most severe effects of any electrical break
- A *transient fault* involves a drop in voltage in an electrical power supply, and it can cause the pumping equipment to stop or generate an improper operation.

The principle of the two types of electrical breaks is illustrated in Figure 41 and Figure 42 respectively:

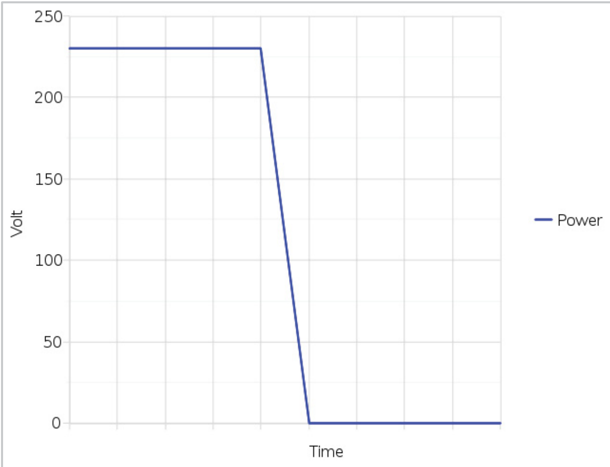

Figure 41: Blackout

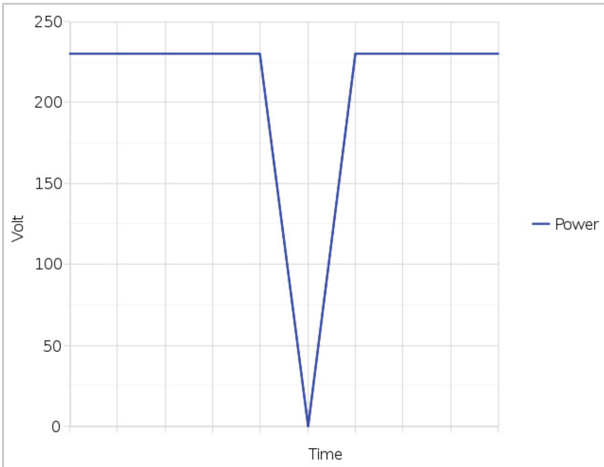

Figure 42: Transient fault

6.5.2 Effect of electrical breaks on different types of artificial lift equipment

PCP

The effects of an electrical break on a PCP can be much undesired. Apart from the production lost, this type of artificial lift system is prone to severe failure and generates a safety risk due to its backspin behavior. If the power supply is interrupted, the pump string gets into a backspin due to the torsional strain stored in the rods. The effect of this behavior can be reduced or even stopped by having a backspin arrester system installed on the pump. In OMV Petrom, all wells with PCPs have such a system installed.

ESP

In an electrical submersible pump, when the power is cut off, the pump normally enters a reverse motion until the fluid falls back to its static level. Damage to the pump could appear if power is applied during this time. By the use of a check/drain tubing valve, the liquids stay in the tubing whenever the pump stops operating. This saves the time needed to pump the fluid back to surface from its static level.

SRP

The stop in power supply to a sucker rod pump stops the alternative up-and-down movement of the string, while the fluids remain in the tubing due to the pump intake valve acting as a check valve.

6.5.3 Well level production losses due to electrical breaks

Case 1: Transient fault

When a transient fault occurs in the electrical distribution grid, wells that are connected downstream of the fault shut down immediately. When the electrical power is restored, the well pump(s) remain shut down until an operator manually switches them on again by visiting the wellsite.

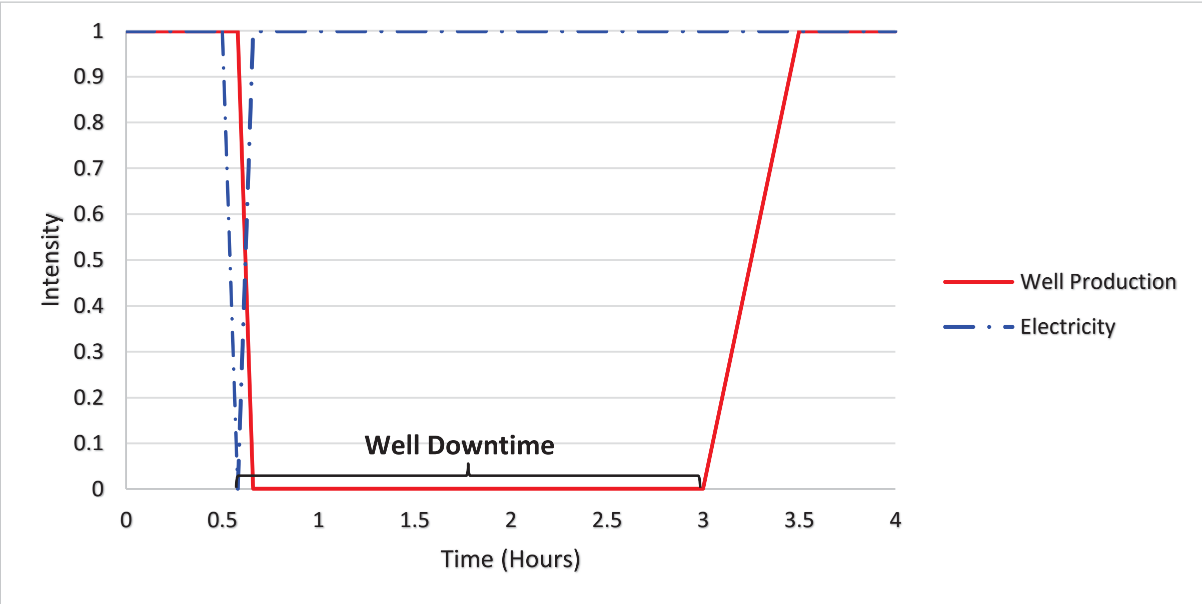

Figure 43: Transient fault well production trend

The average time in OMV Petrom for a well to be put back in production after a transient fault event is two and a half hours, as shown in Figure 43. This well downtime generates deferments and allows in sandy wells for the sand carried with the fluids to settle in the tubing above the pump. This causes problems at pump re-start, which will be discussed in further detail in chapter 6.5.7.

Case 2: Blackout

In the case of a blackout, the time to restore production is higher, because each individual section of the electrical grid (the cable length between any of two pillars) must be tested in order to find the affected zone. The average time for a well that has been affected by a blackout to be put back into production has been plotted in Figure 44 and is eight and a half hours, consisting of an average time of six hours to detect the failure source and two and a half hours to manually start-up the well. For wells prone to sand production, this downtime represents a high concern because it can cause severe problems in pump operation.

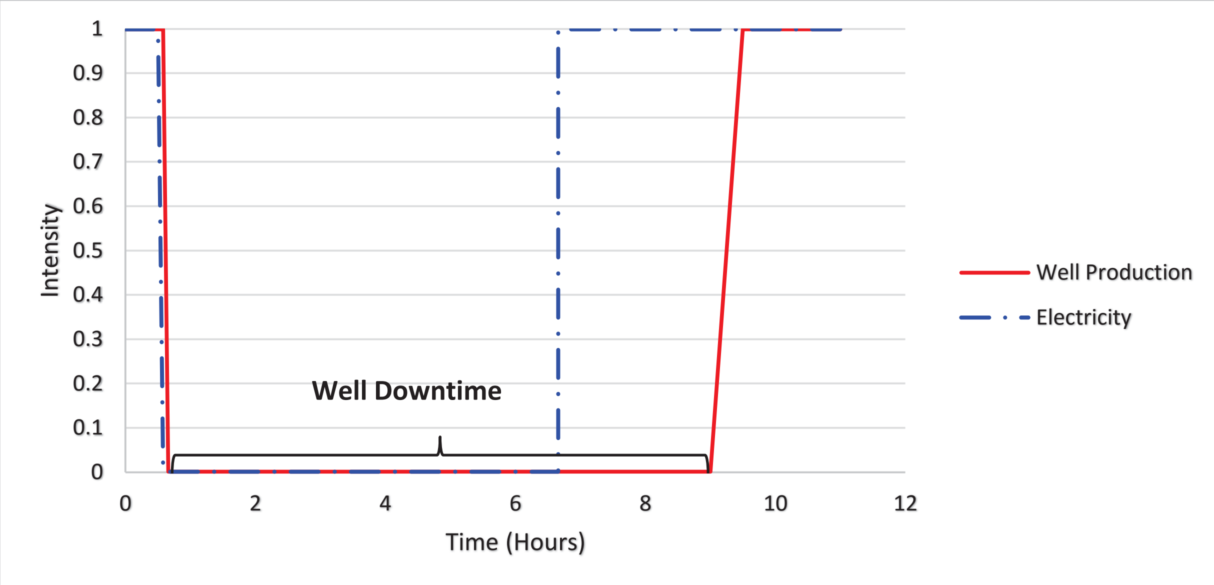

Figure 44: Blackout well production trend

6.5.4 Solutions to reduce production losses

Fault current indicator

A fault current indicator is an intelligent equipment which is mounted on overhead lines and offers a complete solution for failure source detection. The detection model is based on the changes in the magnetic field set up by the fault current.

The device is used to locate short-circuit /Phase To Phase (PTP) - and earth faults/Phase To Earth (PTG) in overhead line distribution networks. It is a 3-phase unit fully covering the different fault configurations that may occur.

The indicators are placed at strategic locations along the line such as after branching points and sectionalisers. They are mounted on the pole, 4-5 meters below the conductors, by means of screws or wrapping-bands. Live line mounting is done safely, easily and rapidly. Power supply to the indicator is done by batteries.

Upon detecting a fault on the line, the indicator gives off an intermittent red or green light-flash (LED). One LED flashing indicating an earth-fault and both LED flashing indicating a short-circuit fault. The colours of the LED will also indicate direction to the fault location for earth-faults. [11]

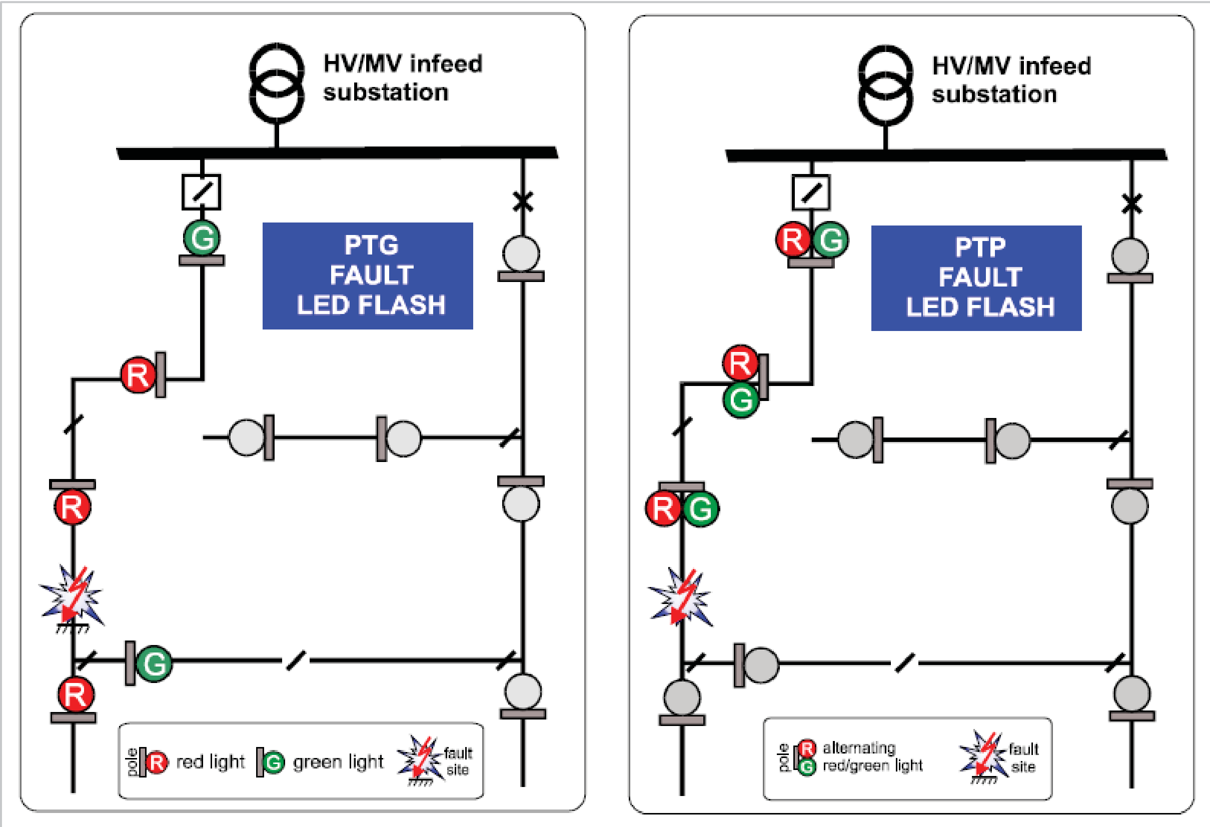

Figure 45: Fault source display using fault indicators [11]

Upon sensing an earthfault (PTG) all indicators installed on the feeder with fault both upstream and downstream will operate. Upon sensing a short circuit fault (PTP) only indicators installed between the feeding transformer and the fault location will operate. The difference between a phase-to-earth and a phase-to phase fault is illustrated in Figure 45.

In connection with remotely controlled outstations, the indicator can be connected to a RTU (Remote Terminal Unit) giving the SCADA operators immediate information of the fault location, as shown below in Figure 46.

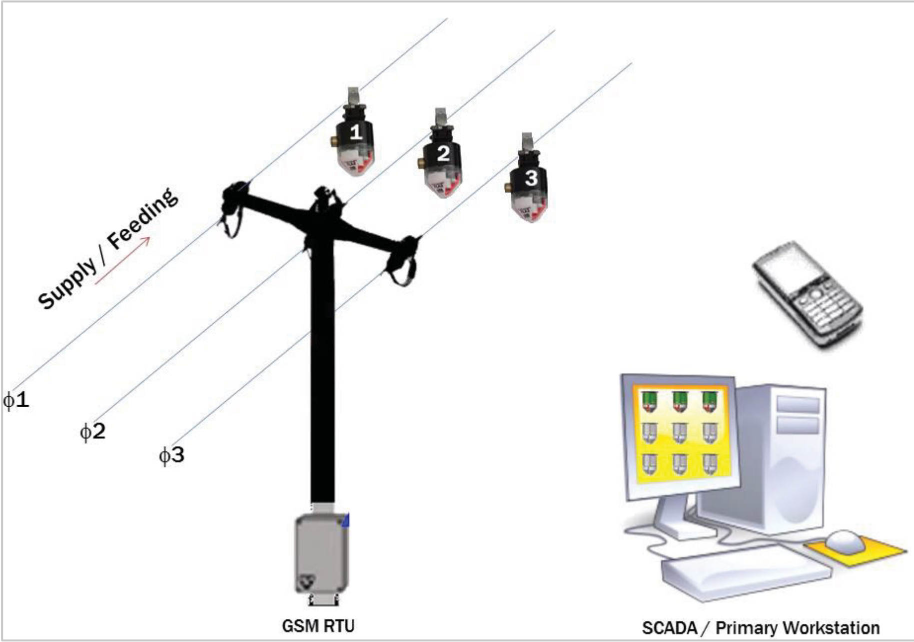

Figure 46: Fault monitoring using a SCADA system

The advantages of using this technology are the following:

- Quick localization of potential failure and reduced electrical downtime;
- Removed attempts for failure detection and for failure isolation done through connecting and disconnecting the power in the line for each two pillars interval
- Reduced production losses
- Reduced maintenance costs
- Reduced HSSE risk of human injury by electric shock
- The device is autonomous, not requiring power transformers or connections to other system

Remote start-up

Currently, in OMV Petrom, 38%, or 3,900 of the wells are automated. For these wells the remote start-up procedure can be adopted very easily by using the capabilities of the real-time monitoring software and setting timers.

There are two impediments which stop the application of this. The first one is that the controllers installed at well level do not have a procedure programmed into them to time the well restart, and the second one is a company procedure requiring a well visit by the operator in order to re-start the pump. The operator checks the pump and makes sure that it is safe to bring it back into production. However, all of this effort could be saved by beginning to trust the measurements made automatically and the information received by a remote system. Reprogramming the controller to allow pump restart should be done by the IT department in the company and the pump visit procedure should be eliminated because having a manual procedure when an automated one is available has no benefit.

6.5.5 Possible reduction in production losses

By using the technology and the process described above, a reduction in production losses can be achieved on the company level.

In case of a blackout, the source can be immediately identified and remediated by using the fault indicators, saving an average of up to five of the six hours lost in the normal case, as several pilot deployments reveal. Manual start-up time is completely eliminated by the remote start-up process. The final impact of an electricity blackout is reduced to a total loss time of one hour, which represents an 88.2% decrease from the initial eight and a half.

For a transient fault, the loss is reduced almost completely, because the only technology influencing the loss is the remote start-up, which is activated instantaneously. In order quantify the loss reduction in a well suffering from a transient failure a 100% improvement is not realistic due to the deceleration of the downhole pump after the power outage and the time it takes to accelerate back to prior full pumping speed. To account for the dynamic losses, a 95% improvement is considered hereafter.

A summary of the changes in well level downtime after implementing the Digital Oilfield Approach is presented in Figure 47.

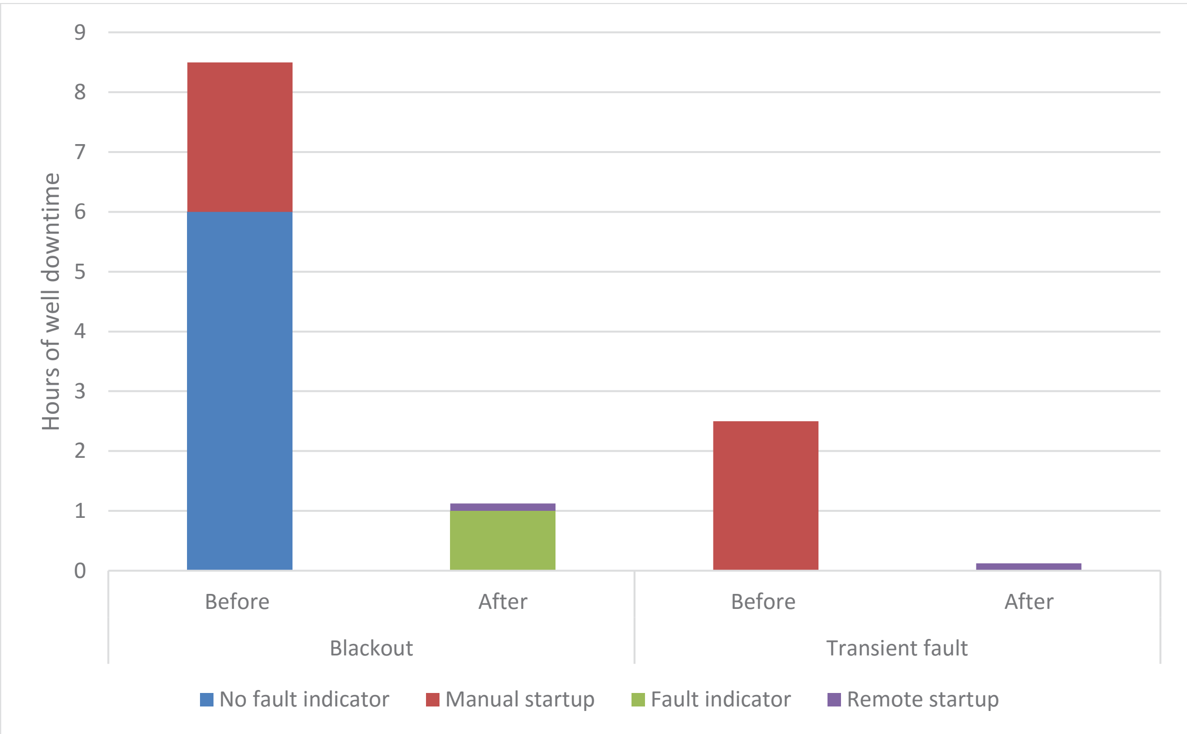

Figure 47: Average well downtime after electrical breaks before and after DOF approach

6.5.6 Economic analysis

The economic analysis of this project was done for a period of 5 years, starting mid-2016. As a result the incremental production and the OPEX for the first year were accounted as half the normal yearly level. The revenues and costs are calculated for a base case oil price of 60$/bbl and a sensitivity analysis has been performed for 3 revenue scenarios: 2015 – base case, +25% incremental production, and -25% incremental production, and for 3 oil price scenarios: 45, 60 and 75$/bbl.

The taxes considered for the analysis were a royalty tax of 4% of the oil production, a production tax of 0.63$/bbl, and a profit income tax of 16%.

Benefits

In 2015, the number of occurrences of blackout events on wells in OMV Petrom represents an average of 10% of the total events, with the other 90% being minor transient events. The total losses on company level due to electrical breaks were of 12,226 tons. The losses caused by transient events were of 6,558 tons and the ones by blackout events were 5,668 tons. The losses after implementing the new technology would be 328 tons for transient failure and 669 tons for blackouts, yielding a total of 997 tons and a reduction of 11,229 tons from the initial 12,226, or 92% less losses.

By taking the petroleum specific gravity of $0.88\ g/cm^3$, which is the average value per well in OMV Petrom, it is known that:

$$1\ barrel = 158.987\ liters$$

So, one barrel weighs:

$$158.987 * 0.88 = 139.908\ kilograms$$

And one metric ton (1,000 kilograms) is:

$$\frac{139.908}{1{,}000} = 7.147\ barrels$$

Thus the saved production losses due implementing the DOF approach are:

$$11{,}229\ to * 7.147 = 80{,}259.3\ barrels$$

At a Brent Crude oil price scenario of $60 per barrel, that results in an yearly extra company income of $3,883,266 or €3,378,441 (at a conversion factor of 0.87€/$) by using the fault current indicator and remote start-up technologies presented above.

The benefits for each approach separately are presented below.

Fault current indicator benefits

By using the fault current indicator only, production losses would be 2,334 tons for the blackout events and 6,558 tons for the transient events, or a total of 8,892 tons. This represents a saving of 3,334 tons from the initial 12,226 tons. The extra company income would be $1,151,770 or €1,002,040.

Remote start up benefits

By using only the remote start up technology, production losses would be 4,000 tons for the blackout events and 328 tons for the transient events, or a total of 4,328 tons. This means a saving of 7,898 tons from the total initial 12,226 tons. The extra income on the company level would be $2,728,457 or €2,373,758.

A comparative view between initial production losses and losses after adopting the DOF approaches can be seen in Figure 48.

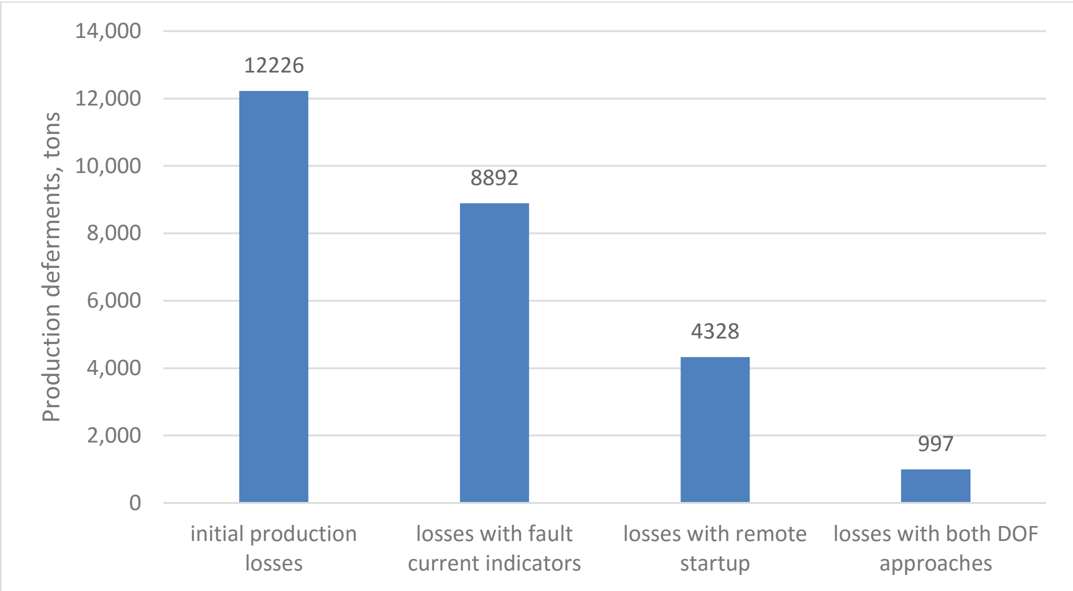

Figure 48: Production losses comparison before and after DOF approach

Fault current indicators costs

The device associated cost are shown in Table 18, and represents €2,501.5 (containing the fault current indicator device cost of €1537.6 and the GSM RTU cost of €942.4). Additional costs include a €48 per year SIM Card Data Transmission Subscription, €4556 for a central GSM Reception Kit at the headquarters, and €4328 for the licensed software kit.

Component	Cost/Item (€)	Multiplication factor
Fault Current Indicator	1537.6	yes
GSM RTU	942.4	yes
SIM Card Data Communication Yearly Subscription	48	yes
GSM Reception Kit	4556	no, 1 at Headquarters
Licenced Software Kit	4328	no, 1 at Headquarters
Device Installation Manpower	21.5	yes

Table 18: Costs associated with the fault current indicator system

Installing the device at the company level would mean integrating the system for more than 8000 onshore wells under the domestic ownership of OMV Petrom. Several pilot deployments of this device have already been made on asset level in the company, with an average of 16 fault indicators mounted per 100 wells. The pilot locations were chosen on structures with medium complexity and ramifications, which comforts an extrapolation to the company level. Such an example is the deployment to the Paduroiu Vata field, illustrated in Figure 49, with 23 indicators guarding for 140 wells. The fault indicators are illustrated by the symbol .

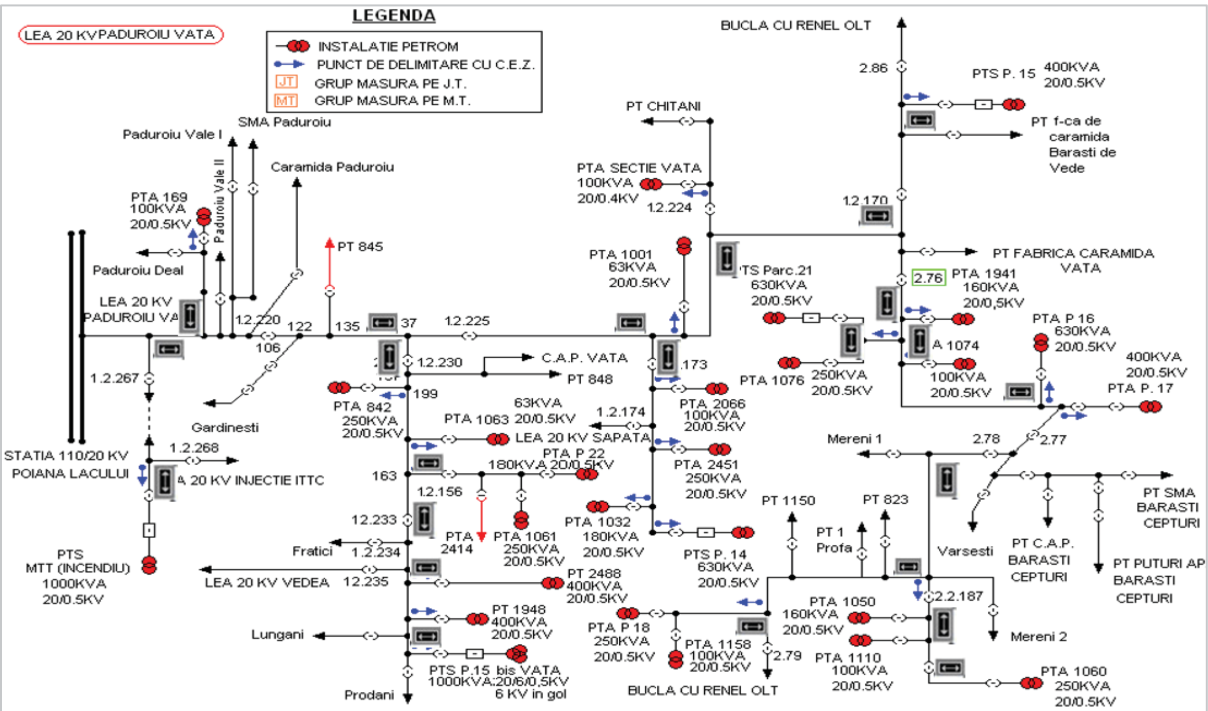

Figure 49: Pilot deployment example, with 23 indicators guarding 140 wells [12]

Based on the OMV Petrom well database, to monitor the electrical grid for the entire 8000 wells would require an average of 1314 fault current indicators. The associated CAPEX is listed in Table 19.

Table 19: CAPEX of fault current indicators in electrical lines

Net Capital Costs	
Fault current indicators	€ (3,267,604)
Installation	€ (28,251)
Total Capital	**€ (3,295,855)**

OPEX for the first 5 years of the project, including data communication yearly subscription of 48€/item and assuming a cost escalation factor of 2% each year, are presented in Table 20:

Operating and Maintenance Costs	Year 0	Year 1	Year 2	Year 3	Year 4
Operation	€ (31,536)	€ (63,072)	€ (63,072)	€ (63,072)	€ (63,072)
Escalation of Costs		€ (1,261)	€ (2,548)	€ (3,861)	€ (5,199)
Total Costs	**€ 63,072**	**€ (64,333)**	**€ (65,620)**	**€ (66,933)**	**€ (68,271)**

Table 20: OPEX of fault current indicators in electrical lines

The business case results of installing fault current indicators are presented in Table 21. The NPV of the cash flow is calculated for a period of 5 years and the discount rate is set at 15%

Table 21: Business case results of fault current indicators in electrical lines

NPV of Cash Flow	**€ (154,172)**
IRR	**€ 0.12**
Profitability Index	**€ 0.95**
Discounted Payback (15%)	5 Years 2 Months

The CAPEX, OPEX, and Revenue are shown as they develop throughout the years in Figure 50.

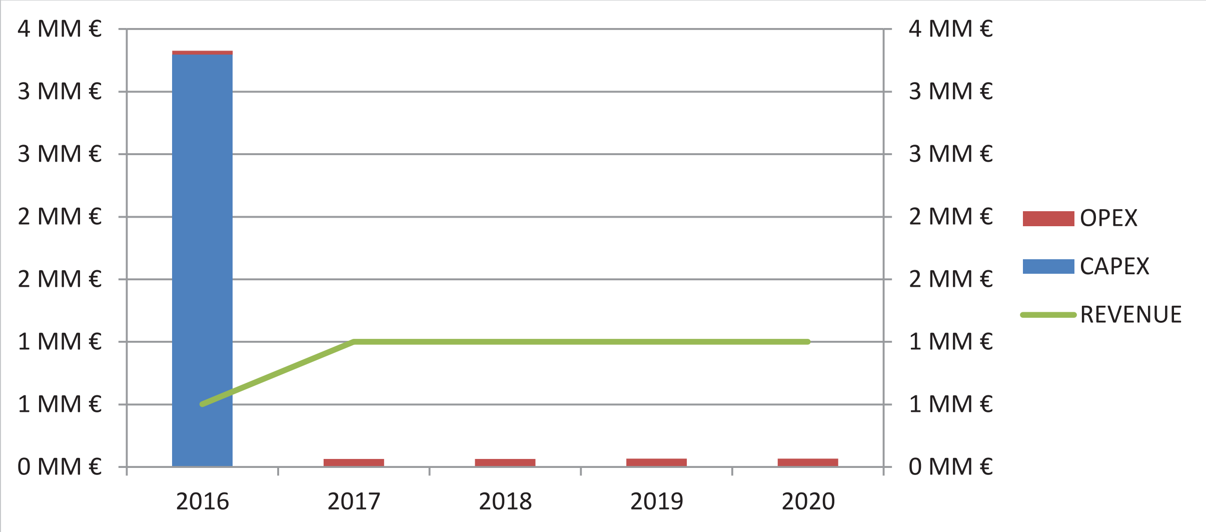

Figure 50: CAPEX, OPEX, and Revenue of fault current indicators in electrical lines base incremental production case 60$/bbl

Sensitivity analysis for fault current indicators

Because the incremental production which can be achieved by the DOF approach is a variable that can change from the reference value calculated for 2015 and because the oil price is also uncertain, a sensitivity analysis was developed for the project for 3 revenue scenarios: 2015 – base case, +25% incremental production, and -25% incremental production, and for 3 oil price scenarios: 45, 60 and 75$/bbl.

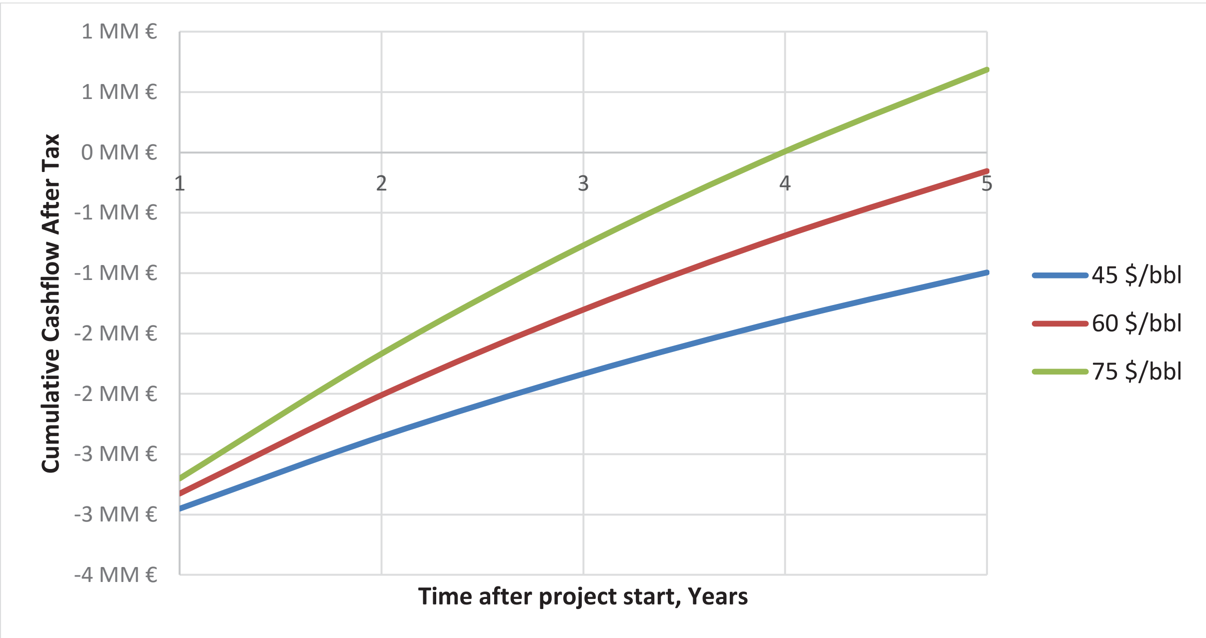

Figure 51: Cumulative cashflow fault indicators base incremental production case

For the base case, illustrated in Figure 51, the project hits the breakeven point after 4 years for a 75$/bbl oil price, but fails to pay out in the first 5 years for an oil price of 45 or 60$/bbl.

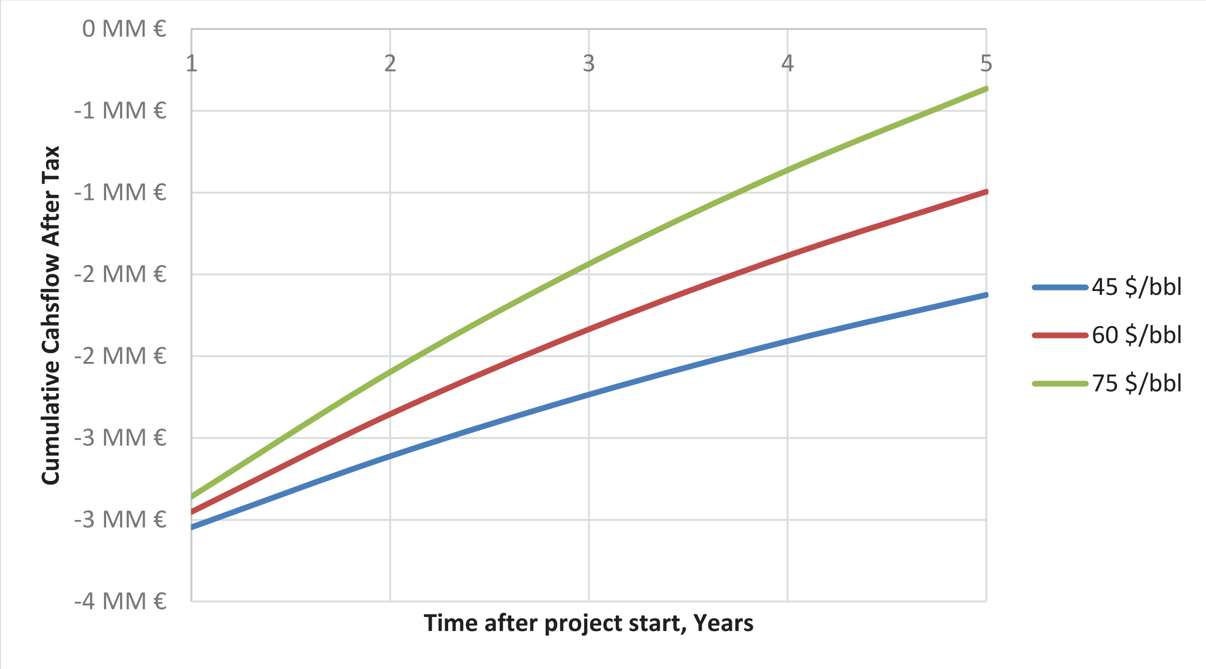

Figure 52: Cumulative cashflow fault indicators -25% incremental production case

If the incremental production decreases by 25%, than the project is unfeasible for any of the 3 oil price scenarios, as shown in Figure 52.

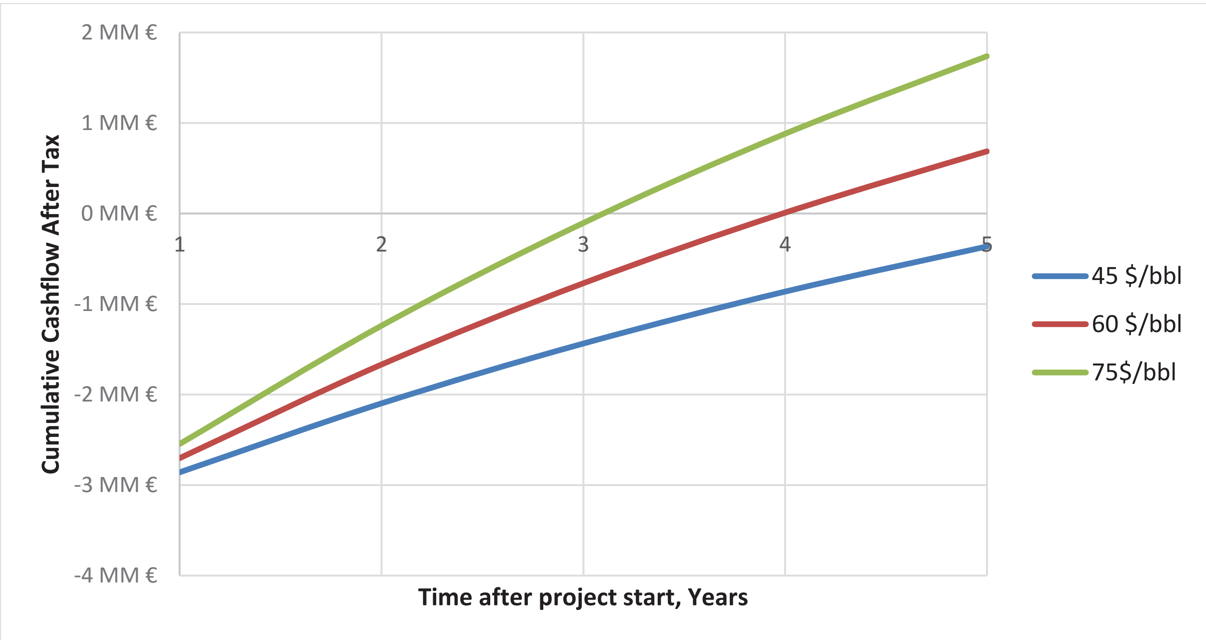

Figure 53: Cumulative cashflow fault indicators +25% incremental production case

In case the incremental production due to using fault current indicators would increase by 25%, only the 60$/bbl and the 75$/bbl scenarios would hit the breakeven point in the first 5 years, as shown in Figure 53.

Remote start-up costs

The cost of having a remote start-up for the wells with an automation system fitted consists of the cost of re-programming the existing controllers to allow pump restart after electrical breaks. This is a maintenance work which can be done by the IT with no extra cost, provided that the equipment has been properly calibrated and the information received can be trusted.

Out of the 7,898 tons of production which could be saved in the year 2015 by implementing a remote start-up procedure for all the onshore wells in the company, in wells fitted with WA a production of 3,159 tons can be saved. Installing well automation on the remaining wells is a subject of great cost and complexity and requires a deeper analysis which is not in the scope of this thesis.

The revenue of enabling the remote start-up procedure for automated wells in 2015 would be $2,819,586 or €2,509,432.

6.5.7 Extra benefits of reduced downtime after electrical breaks

Sand settling

In sandy wells, when an electrical break occurs and the well pump stops, the sand carried with the fluids in the tubing begins to settle on top of the pump. It has been proven with a correlation in chapter 5.6 that in 2014, on the company level, 47.5% of the total downhole pump failures within 4 days after an electrical break are due to sand, and in 2015 59.8% are due to sand. By reducing the downtime after electrical breaks there is less time for the sand carried with the fluid to settle, which can reduce the number of pump failures.

Case study company level

The terminal velocity at which sand particles set is derived from Stokes Law equation, as follows:

$$V_t = \frac{gd^2(\rho_p - \rho_m)}{18\mu}$$

where:

$V_t = terminal\ velocity$

$g = acceleration\ of\ gravity$

$d = particle\ diameter$

$\rho_p = particle\ density$

$\rho_m = density\ of\ medium$

$\mu = viscosity\ of\ medium$

Taking the average values extracted from the company database, the following were considered: an acceleration of gravity $g = 9.8\ \frac{m}{s^2}$, a sand particle diameter $d = 0.25\ millimeters$, a density of the sand particle of $\rho_p = 2200\frac{kg}{m^3}$, a density of the oil of $\rho_o = 880\frac{kg}{m^3}$, and a viscosity of the medium $\rho_p = 2\ cP$, and the following was derived:

$$V_t = \frac{9.8 * (0.25 * 10^3)^2(2200 * 10^3 - 880 * 10^3)}{18 * 2}$$

$$V_t = \frac{0.022 meters}{second}$$

$$V_t = \frac{82.687 meters}{hour}$$

$$V_t = \frac{1,984,499 meters}{day}$$

This means that it takes approximately 1 day for the sand carried with the hydrocarbons in a 2,000 m borehole to completely settle, when the well is shut down.

The average depth of wells in OMV Petrom is 1,500m, and considering the parameters used in the Stokes formula it takes approximately 18 hours for a well of average depth to have all the sand on top of the pump, so the critical downtime is between 0 and 18 hours.

Case study Independenta sector

The average depth of the wells in the Independenta production sector is 765 meters, and considering the information found in the company database the following were considered: an acceleration of gravity $g = 9.8\ \frac{m}{s^2}$, average sand particle diameter $d = 0.25\ millimeters$, a density of the sand particle of $\rho_p = 2300\frac{kg}{m^3}$, the average density of the oil of $\rho_o = 930\frac{kg}{m^3}$, and a viscosity of the medium $\rho_p = 3\ cP$, and the following was derived:

$$V_t = \frac{9.8 * (0.25 * 10^3)^2(2,300 * 10^3 - 930 * 10^3)}{18 * 3}$$

$$V_t = \frac{0.0155 meters}{second}$$

$$V_t = \frac{55.941 meters}{hour}$$

$$V_t = \frac{1{,}342.599\ meters}{day}$$

The time it takes for the sand settle to the average depth of the wells in Independenta is 13.7 hours, so the critical downtime is between 0 and 13.7 hours.

In Figure 54 below, the year 2015 was taken as a reference for a correlation encompassing all the onshore wells in OMV Petrom. As can be seen, the percentage of pump failures due to sand out of total pump failures increases with increased downtime after electrical breaks.

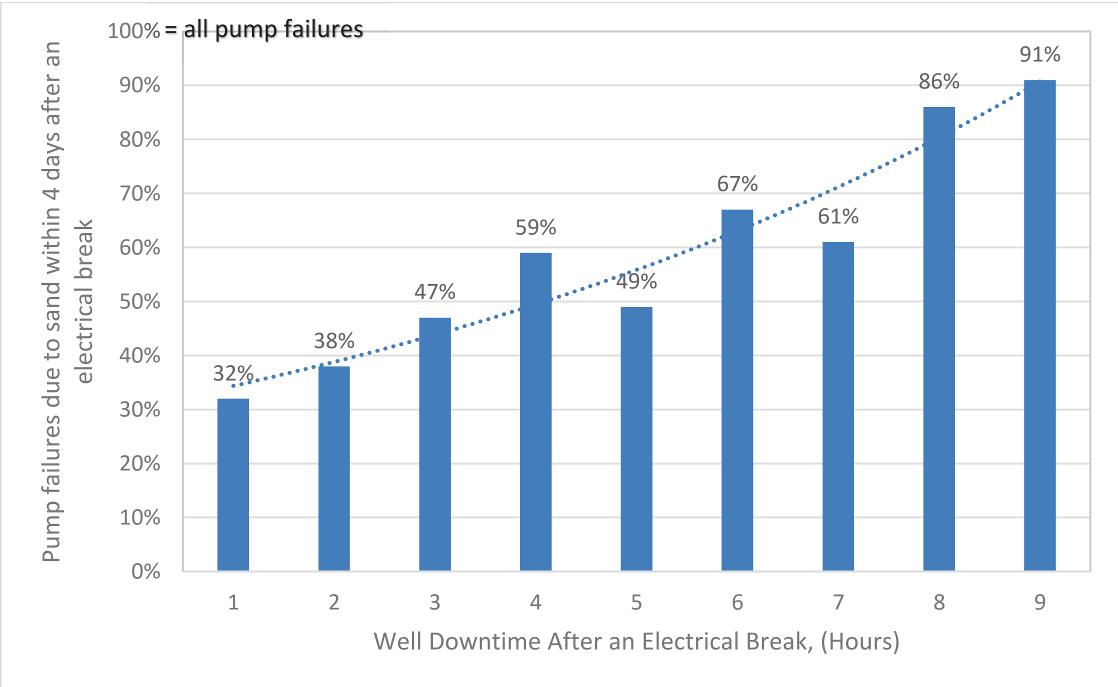

Figure 54: Correlation between well downtime after electrical breaks and the percentage of pump failures due to sand within 4 days after the electrical break

In 2015, an average of 59.8% of the pump failures which occur within 4 days after electrical breaks are caused by sand. If average well downtime after electrical breaks could be reduced to 1 hour, then a 32% of pump failures due to sand could be achieved. This means that out of the 87 pump failures only 28 would be for sand reason. Comparing with the current number, 52, that results in 24 prevented pump failures.

At an average pump repair cost of €4000 and a well intervention cost of €8000 per well, the yearly saving on the company level would be €288,000.

7 Loss management

7.1 A view on loss management

The oil industry is increasingly confronted with challenges: drop in oil prices, increased costs for processing sour gas or oil, modernisation, greater regulation and new energy strategies. It is more costly and riskier to access and exploit reserves, as production moves to deeper water and HPHT reservoirs. Many strategies are implemented in the industry in order to stay competent and cost-effective. One of the core ones is Operational Efficiency. It allows companies to sustain greater productivity by implementing the operational strategy carefully.

It is vital to successfully manage production losses for reaching high operational or production efficiency. Operators can increase reserves recovery, enhance production, and decrease environmental damages and risk by embracing effective production loss management strategies. In the following pages, the best production loss management techniques are presented.

7.1.1 Overview on Efficiency & Production Loss Management

Production efficiency is an asset's production performance and a key performance indicator for operators. The formula for calculating it is the volume of oil and gas produced divided by the maximum production potential.

$$Production\ Efficiency = \frac{(Total\ Export + Total\ Fuel + Total\ Flare + Shrinkage)}{Maximum\ Production\ Potential}$$

Operational efficiency is similar to production efficiency but it includes the losses planned in the annual production plan, plant shutdown and the decrease in production volumes due to 3rd parties (government limitations). The formula below makes understanding easier:

$$Operational\ Efficiency = Production\ Efficiency + \frac{Total\ Planned\ Losses + 3^{rd} party\ unplanned\ losses}{Maximum\ Production\ Potential}$$

Production loss management relies on the following values:

- Clear definition of the maximum production potential of wells to allow production loss monitoring and administration
- All losses must be noted for gas, condensate, crude oil, etc.
- $\text{Production Loss for a particular time period} = \text{Maximum Production Potential} - \text{Gross Volume Produced}$
- The same procedure as for production allocation should be used for losses (recording, classification and allocation to well); unaccounted losses should not exceed 5-6% of total losses
- No loss or gain is to be accounted with respect to any commercial swap arrangements
- Pressure, temperature and phase change should be considered when counting losses

It is essential to have a precise maximum production potential, in order to have a point of reference against which to monitor production, capture and quantify loss events. Several nodes are integrated in the production system: reservoir, wells, network, surface facilities and export. The production potential of the whole system is derived by calculating the production potential of each node and taking the lowest one as the constraint for the system. Any production level below this potential level is considered a loss and requires management.

7.1.2 Loss Management Process

An optimized loss management process should have the next stages:

- Loss event capture
- Event validation, quantification, and classification
- Loss event investigation
- Evaluation and Action

Loss event capture

Any such event should be noted in terms of start and end time and initial activities such as volumes approximations, loss classification and high level root cause analysis should be started. The duty to capture and pass the precise data to the production engineer lies with the production supervisor.

Event validation, quantification and classification

A comparison should be done between the production potential and the actual production allocation at well level for the end of the day. The production potential is calculated as stated previously. At that point, the loss events, volumes and loss category sent by the shift supervisor should be looked over. The responsibility of loss validation lies with the production engineer.

All loss categories must be recorded by the company asset, as well as all the circumstances in which losses could occur. A few categories could be:

- Planned losses: These losses usually occur due to predicted maintenance and are caught into the yearly production proposal
- Unplanned losses: These losses occur due to electrical breaks, shutdowns or overestimates and are not predicted in the yearly production proposal
- Potential losses: Such losses occur in wells suffering low production, when the smaller production from the well is compensated by growing production in another well
- Losses allocated to motives like: corrosion, fatigue, age-wear, carbonate buildup, sand buildup, load stress, etc.

A team led by the asset manager must evaluate the losses. A system in which loss accountability is divided between loss owners can be created. Examples of such owners could be the head of departments of subsurface, offshore operations, onshore operations, or pipeline operations. A review of losses should be scheduled at an interval suitable for the company and corrective actions should follow.

In order to have a systematic action plan, an assessment should be done of how specific losses affect HSSE, economics, commerciality, the produced volume, and workover/maintenance cost.

Loss event investigation

Root cause analysis should not be carried for every loss event. Depending on the impact they have on the production volumes, loss events should be prioritized and criteria must be defined where a root cause analysis is needed. Such conditions are:

- Repeated or frequent failure of equipment caused by the same reason
- Failure caused by asset integrity issues (high corrosion, loss containment, emergency shutdown)
- Loss greater than 5% of maximum production potential

The loss owner is responsible for making sure root cause analysis is performed in time and corrective actions are applied to reduce loss and prevent its future appearance.

Loss Managing Team

It is essential to identify every single person responsible for handling losses in the asset. The team includes the field level shift supervisor, the one who reports a loss event, the production engineer who validates and confirms the loss, and a loss investigation team nominated by the asset manager, who is the loss owner that implements the corrective changes.

Loss managing meetings

Losses and loss root cause analysis action points have to be checked in detail in a loss review meeting every week, every 2 weeks, or every month. The meeting discusses how the loss will be managed, taking into consideration the next points:

- The loss is allocated to the loss owner, which is, depending on the loss, the head of a specific department. For instance, if a gas compressor failure generated the loss, the responsible person should be the onshore operations head
- A fixed end time should be defined for each action plan point
- The loss can be reassigned to the well potential because it is not produced
- The opportunities for loss recovery should be evaluated, along with an economic calculation, and confirmed into the integrated production system restraints.

Loss Management Reports

The assets should deliver the next loss reports:

- Daily loss report: daily loss events, time of occurrence, loss category and explanation
- Weekly loss status report (contains a graphical representation of daily month to date production versus potential production)
- Weekly loss KPI report – year to date, real loss versus planned loss and maximum production potential, year to date loss, top loss causes, maximum production potential versus actual production on well level, and so on.

It is highly important to preserve or increase production levels throughout the life of a field. Reducing production losses can generate added payback on the capital investment. The main goal of loss management is to detect the loss, count the volumes lost, classify the loss and examine its root cause in order to apply corrective and preventive action. Regular meetings of the staff should help to define responsibility, monitor and act on losses. The process helps to increase asset production efficiency and monitor key performance indicators. [13]

7.2 Loss management in OMV Petrom

7.2.1 Current situation

Over the last few years, OMV Petrom has deployed several loss management strategies throughout its assets, as part of its Automation Excellence program.

Many of the component capabilities of a fully integrated digital oilfield are already underway:

- 38% of the wells (3900) and 19 % of the compressor stations are automated
- More than 300 monitoring systems for water injectors are available
- 15% of the gathering stations have been replaced by measuring point skids
- Real-time optimization/diagnosis & alarm triggered events
- Production data is collected via several tools: PIMMS, XSPOC, Openwells

The next steps in loss management are:

- Data & Workflow automation
- Integrated working with vendors (Expert hub)
- Pump workshop optimization for under-utilized locations transferring expertise into one location
- Identification of bad actors and support of best practice transfer between Assets
- Data repositories cleanup / Full use of XSPOC
- New operations role/responsibility models
- Collaborative Environments (Control Hub)

To effectively manage the production losses in a digital oilfield environment, a fully integrated system is required, involving people, processes and technology. The OMV Petrom mother company's vision, OMV, is about 'Seamless integration of people, processes, information and technology while protecting people, our environment and assets to achieve shared business goals'. A description of the current system status in OMV Petrom is explained in the following paragraphs, considering the foundations of an integrated digital oilfield: Technology, people, and processes.

7.2.1.1 Technology

Up to date, most of the focus in OMV Petrom was in deploying the technology in the field.

The journey of well automation started with a pilot in 2007, at short time after Petrom was acquired by OMV. Prior to that, the only degree of automation present at well level was a tele-mecanization and timer system. Every system counted, more than 4500 wells have a form of automation installed. An overview of the automation system history on well level is presented in Figure 55. The types of automation illustrated are the ones described in greater detailed in the sub-chapter **Types of automation systems on well level in Petrom**.

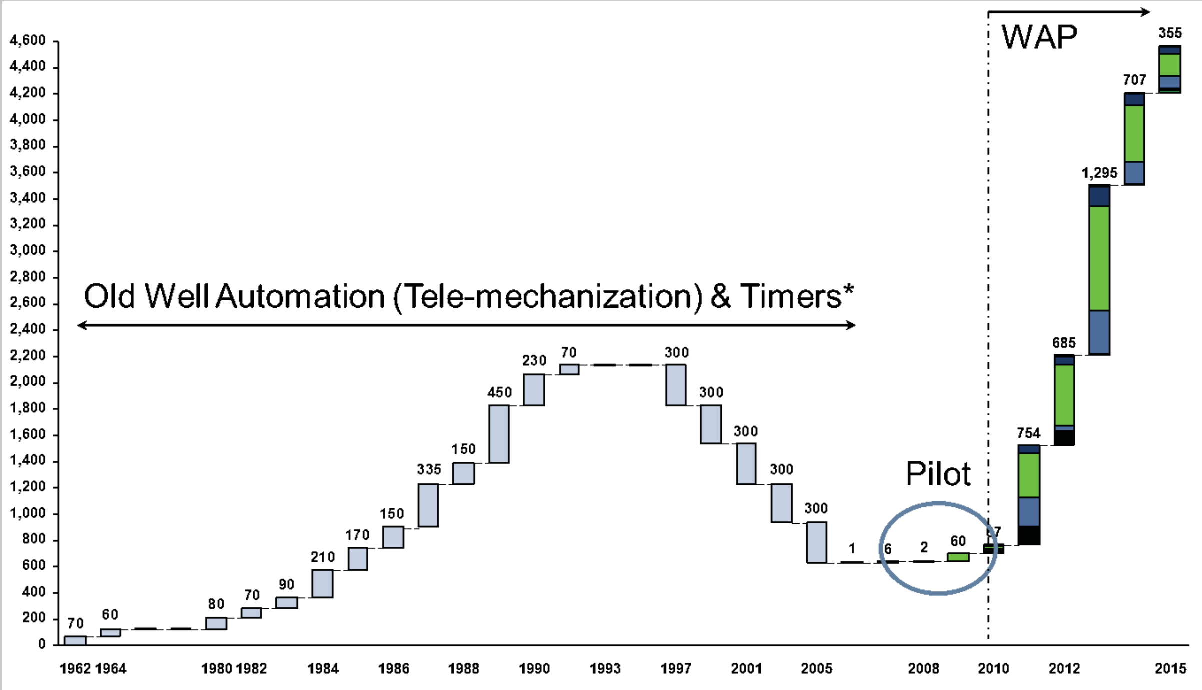

Figure 55: Well automation overview in OMV Petrom between 1962 and 2015 [14, p. 3]

*not in XSPOC, hence not included in well automation project (WAP)

Well automation objectives include:

- HSSE
  - Alarm based surveillance and shut-down
  - Less windshield time (time lost driving between point A and point B)
- Real time access to current operating conditions & optimization
- Increase pumping system efficiency
- Increase MTBF (Mean Time Between Failure)
- Decrease OPEX
- Minimize production losses
- Increase system uptime
- Reduce electrical consumption and equipment repair costs

Types of automation systems on well level in Petrom

Rod Pump Controller (RPC) Automation – SRP, 2565 installations

- Automatic adjustment of pump speed to increase pump efficiency, reduce wear and energy consumption
- Remote monitoring and analysis of well performance in real-time from office

PCP Automation – PCP, 855 installations

- PCP controller is used to optimize well production avoiding pump-off or torque issues.
- Control is achieved by monitoring flow rate and adjusting speed

Linear Rod Pumping Unit – LRP, 400 installations

- automatic pumping speed adjustment;
- measure and display of power consumption;
- calculate an instantaneous well fluid rate;
- recommended for shallow wells and heavy oil reservoir

ESP – 60 installations (on/off-shore)

- measured data:
    - Average amps and voltage
    - Discharge/intake pressure and temperature(offshore)
    - Vibration (3-axis)
    - Motor temperature at windings
    - Drive frequency

Gas well guard and surveillance – 18 installations

- Automatic emergency shut down well
- Data and alarms transmission system
- Pressure, temperature, gas and liquid flow rates measurement

Tele-mechanization – 670 installation live + 565 installations dormant

- Remote monitoring of well pumping parameters, measured by installed devices, in a central control room
- Manual intervention required to adjust well parameters

MURAG 20 – 20 installations

- The device uses electronically generated signal patterns
- Fluid level identification by signal pattern analysis (including frequency analysis)
- Relative accuracy of measurement +/- 3m (at 1 minute intervals)
- Very effective in combination with Variable Speed Drives

Well automation results

Between 2009 and 2015 approximately 3900 automation systems were installed on wells. The result is the reduction in the average number of interventions/well/year from 4 to 2.5. Moreover, the equipment repair and maintenance costs were reduced by 18%. A comparative view of the average run-time of wells in each asset before and after well automation is shown in Figure 56.

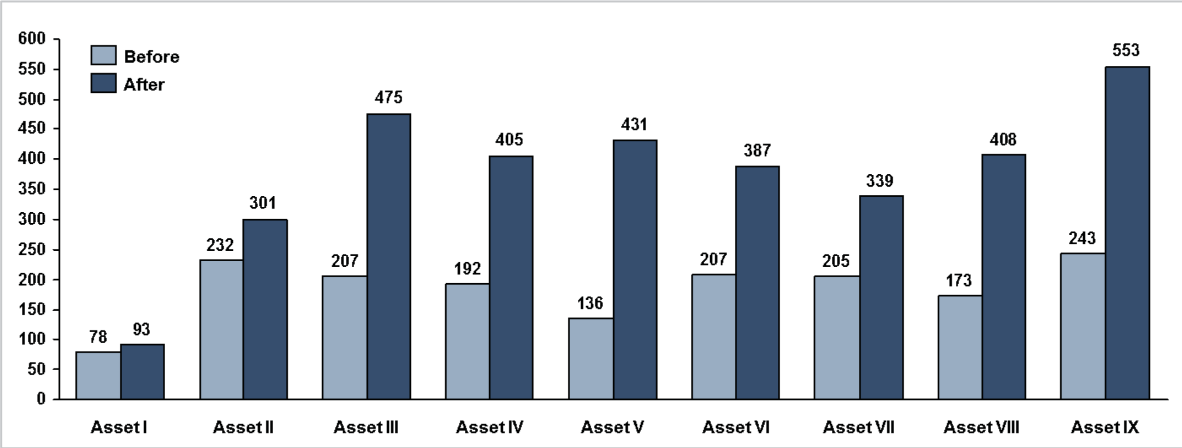

Figure 56: Average run-time of wells per asset before and after automation (days)

However, there are some lowlights too:

- 25% of wells with WA on manual, thereby bypassing WA system
- More than 1000 wells with communication problems
- High amount of wells with pump efficiency less than 55% despite WA in place
- PIMMS – XSPOC data difference
- WA installed on wells with long shut-in status
- Erroneous alarms from XSPOC
- Well visits/MWA identified faulty sensor/controllers/ cables and inadequate set points
- Remote trouble shooting not used requiring field visits

7.2.1.2 People

Companies implement technology to increase productivity, decrease the costs and to make business operations more efficient. However, if the technology is set in the field and the people do not adopt it then the whole system does not work and the investment has no profit. OMV Petrom is aware of this vision and has provided numerous trainings by internal / external automation experts for the employees in each asset.

7.2.1.3 Processes

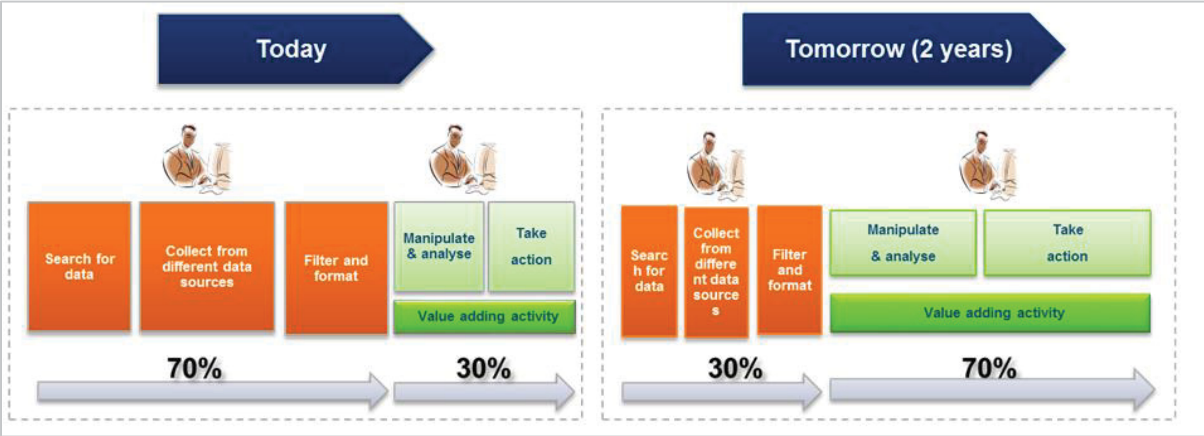

Figure 57: Turning data into valuable information in OMV Petrom [15]

Up to date, there are multiple production data collection formats which need to be integrated on the company level. Assets implemented different solutions so, when data is centralized to the headquarters a lot of time is spent to search for the right information, combine different sources and apply a common format to all of them. Due to this, a lot of engineering time is lost and not enough resources are spent on value adding activities like data manipulation, analysis and action taking. The process of data management is illustrated in Figure 57, along with a vision for the next two years.

A pump optimization process depends on whether the well is automated or not. Almost half of the wells in OMV Petrom are automated and monitored in XSPOC. The advantage is that they can be optimized faster and any change in the operating parameters can be seen in real-time. This can reduce losses and improve recovery. However, additional problems are currently encountered in OMV Petrom due to faulty sensors which reduce the accuracy of data and generate erroneous alarms in XSPOC. The workflow of a well optimization process for an automated and non-automated well is presented in Figure 58.

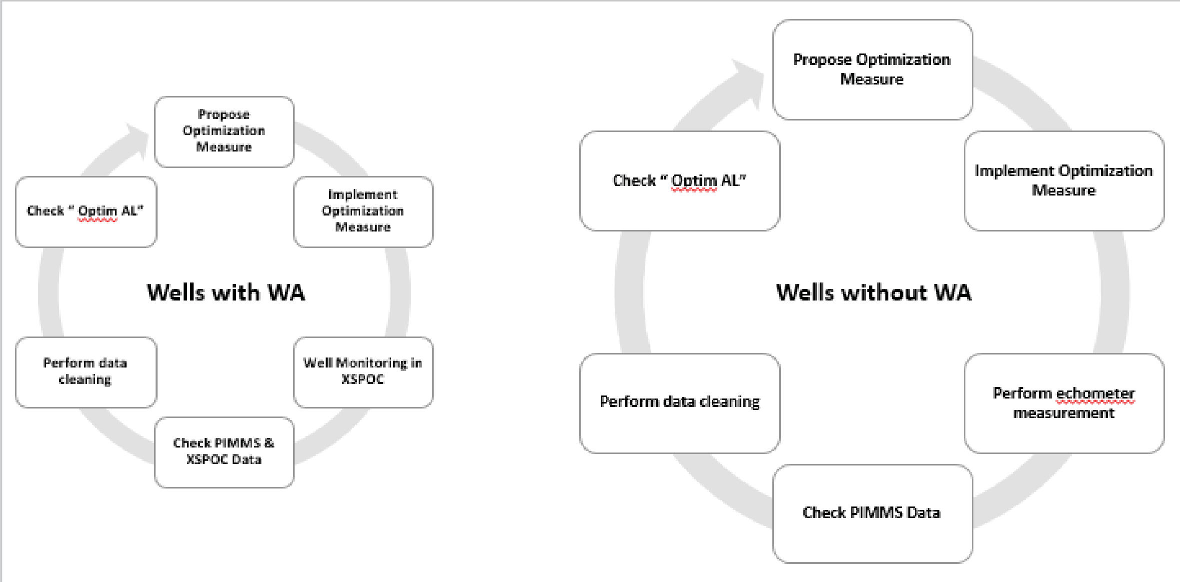

Figure 58: Examples of a pump optimization process

7.3 Loss management ideas and initiatives in OMV Petrom

A systematic approach has been adopted in OMV Petrom in order to reduce the losses by making the automation system work as it should. The steps in this process are:

- Assuring the connectivity is guaranteed with a sufficient bandwidth able to cover 24 hour communication needs from controllers towards server and vice versa to assure access to data from wells in real time
- Improving input data quality by assuring it is accurate, to enable proper data analysis, monitoring and troubleshooting
- Checking the validity of the output data, which is based on the input data aggregated e.g.: production calculation, pump efficiency, equipment loading
- Assuring controller functionality after maintenance operations, to increase the life time of the equipment
- Implement a continuous improvement culture

7.3.1 Connectivity

In 2014, more than 1000 wells on average per month reported communication failure due to Vodafone* (*data communication provider) coverage issues. The situation has improved for 2015, with an average of only 300 wells per month reporting failure. This represents a 70% decrease, attributed to a network expansion done by Vodafone on request by OMV Petrom, in areas where coverage was poor/ inexistent. This generated added OPEX for the company, which would be paid back due to the benefits of real-time monitoring.

Other connectivity options include a different mobile communication supplier, or fiber optic installation with Communication Box on a Master Well and nearby wells connected to it (cost proportional to distance), but they are less desired than the current option considering the actual low oil price environment.

7.3.2 Input data quality: Data Cleaning

PIMMS is a system used in the company for production reporting, and in this system the well characteristics are also input by the users.

XSPOC is an application used for production monitoring, and well characteristics are here also input by the users.

The input data in PIMMS should be a reference for the input data in XSPOC, and they should match 100%. The fact that the input data is not accurate generates obvious issues in using the remote monitoring system and trusting the output data displayed which is calculated and displayed in XSPOC. The level of input data match accuracy has improved over the timeframe of year 2015 as illustrated in Figure 59 and in 2016, it has reached levels of close to 100%.

Data matching PIMMS vs XSPOC	Jan 2015	Aug 2015	Sep 2015
Run Time, h*	56 %	58%	85%
Plunger size, in*	87 %	93%	96%
Pump Type	86 %	93%	97%
Barrel Length, ft	28 %	69%	97%
Pump depth, m*	58 %	58%	92%
Tubing (size, depth), m	40 %	78%	97%
Sucker Rod (size,depth), m	42 %	75%	96%
Motor, Kw	62 %	71%	96%
Stroke length, m*	87 %	87%	94%
SPM*	72 %	72%	92%
Perforation, m	36 %	42%	54%

Figure 59: Data matching PIMMS versus XSPOC

*important parameters for pump efficiency calculation

The next steps for input data cleaning should be:

- to define a process for the data cleaning pilot
- finalize all automatic matching reports
- define leading systems or all automatic matching reports
- perform data cleaning in all Assets with IT support
- integrate PIMMS – XSPOC

7.3.3 Validity of output data

Based on input data aggregated, calculation results are exposed towards XSPOC (e.g. production calculation, pump efficiency, equipment loading). The output data can only be valid if the input data is.

7.3.4 Controller functionality

An assessment on asset level concluded that 13 out of 47 wells had broken cables, misaligned or missing sensors. The responsibility with the controller maintenance and functionality lies with the well intervention crew. Before any intervention the controller system must be removed and reinstalled after the intervention is over.

As improvement measure, the maintenance process was revised, and a check list for the well automation components and right place of installation was added. The next step was a re-training of the intervention crew, where they were taught how to integrate WA into their work.

7.3.5 Continuous improvement culture

The reason why the production recorded in XSPOC doesn't match the one in PIMMS is not only input data quality but also faulty sensors or wrong calibration of the sensors. As part of the data cleaning process faulty sensors are replaced and a calibration procedure is developed together with the automation system providers (Lufkin, Weatherford). A calibration manual will be developed and distributed to all OMV Petrom assets.

Figure 60 shows for each asset in the company how many of the total number of SRP wells have a theoretical production (which is calculated using the sensors installed at well level and the well input data available) that matches the actual production results of the well tests within a range of +/- 10%. Figure 61 shows the same percentage of SRP wells on company level that have a theoretical production (which is calculated using the sensors installed at well level and the well input data available) that matches the actual production results of the well tests within a range of +/- 10%.

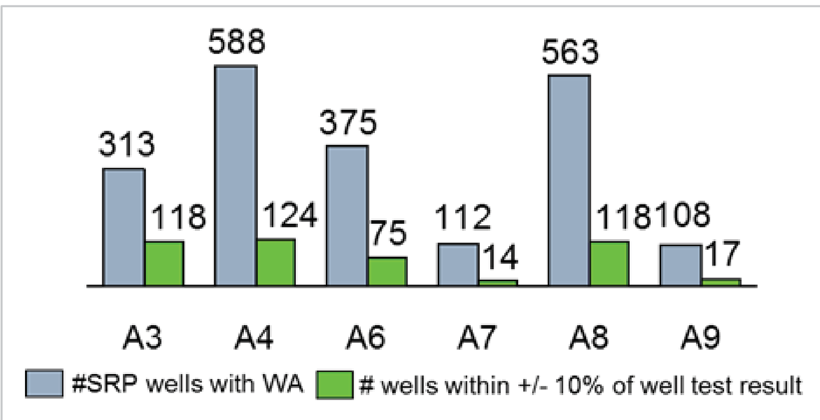

Figure 60: Match between theoretical (calculated) production and well test production results in SRP wells – all assets view

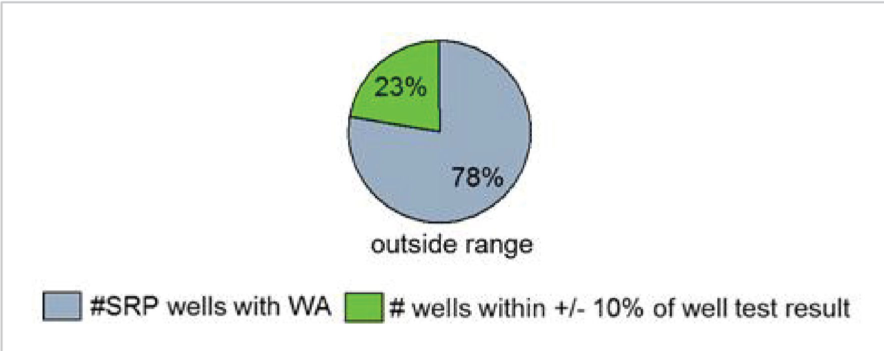

Figure 61: Match between theoretical (calculated) production and well test production results in SRP wells – company view

8 Control hub proposal for real-time monitoring

A control hub is deployed within a Digital Oilfield project for asset production surveillance and optimization. It provides a collaborative work environment between asset teams, the operational staff in the field, experts in the company and other external experts. The entire control hub team is located in the same environment, where it has access to audio-video rooms that share data, connecting the staff located in the field, at sectors, experts from the headquarters, service companies and other key stakeholders.

By implementing a control hub, people, processes, technology and organization are united to materialize the benefits of a digital oilfield approach.

The benefits of control hubs seen in other oil and gas companies are:

- 2-6% production efficiency improvement
- OPEX reduction of 15-25% (or more)
- Improved HSSE

Current situation in the company

OMV Petrom is divided in 8 onshore assets, which in turn have several production sectors. Most of the wells in the company are small producing wells, and they feed into production parks (some automated, some with control rooms). In the offices located at Sector level the staff executes the commands sent from the Asset, where the coordination and optimization of sectors is done. Whenever needed, the staff working at asset level can get expert support from the headquarters. The process is illustrated in Figure 62.

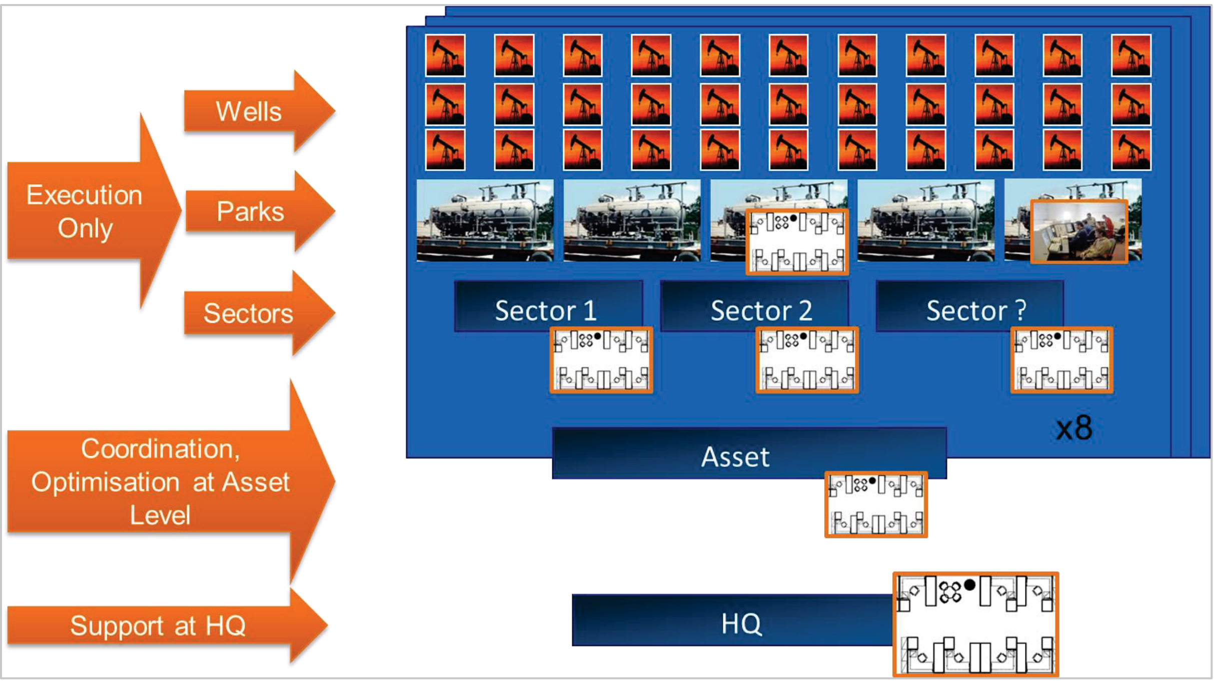

Figure 62: Current organization in the company

Control hub vision

One way of implementing control hubs in the company would be to install one operational hub per each asset, with an expert hub and monitoring room at headquarters level. The assets would monitor real-time production data and collaborate to take best decisions.

The responsibilities of the operational hub would be the following:

- Alarm handling & response for automated equipment including:
  - Wells
  - Well injection
  - Manifolds
  - Measuring Point Skids (for well tests)
  - Flowrate measuring systems
  - Fire/gas/leak detection
- Production trends monitoring
- Electrical system integrity monitoring
- Logistics monitoring
- Staff monitoring

The responsibilities of the expert hub would be the following:

- Condition monitoring
- Pipeline integrity monitoring
- Value chain integration

Setting the control hub at asset location is favorable to setting it at headquarters because the staff is more familiar with the asset configuration and specific facilities. This closeness to operations creates better response times and allows for the creation of expertise at asset level and an easier integration of additional automated facilities in the future.

Real-time remote monitoring rooms would be available at the headquarters, with most skilled staff working in the expert hub and prioritizing intervention on those events that have the most significant impact on production loss. The process of adopting a control hub in OMV Petrom is illustrated in Figure 63.

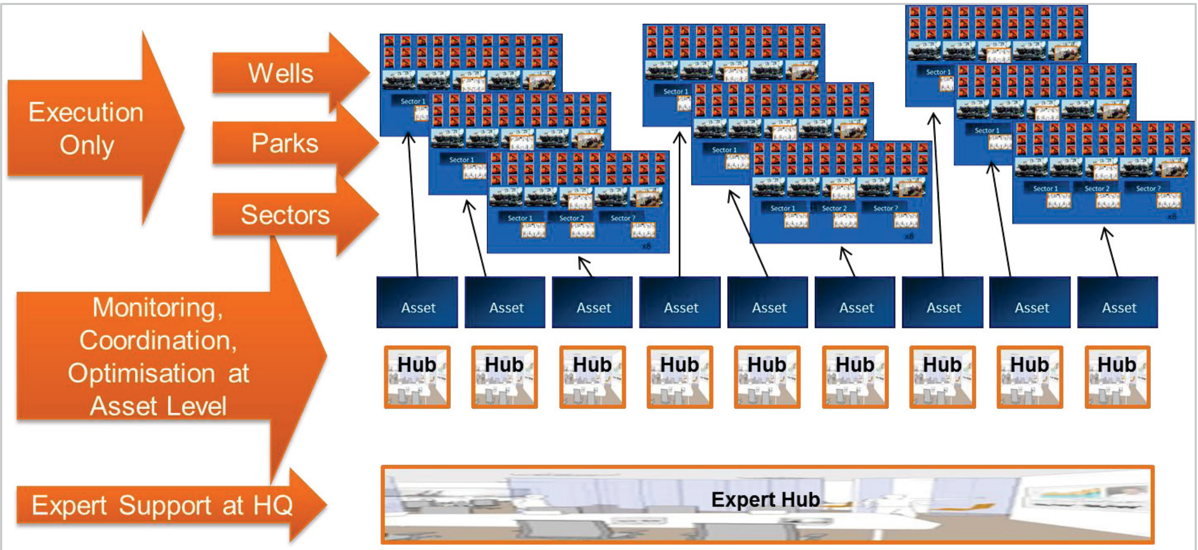

Figure 63: Control hub vision

Because in the current organizational structure of the company the process of data flow is slow and most of the staff is working only the first shift (morning shift) or for 8 hours, some changes need to be made in order to make use of the real-time data for the rest of the hours in a day. As such, for the 2nd and 3rd shifts, a single control room could operate at the headquarters and monitor those important events in each of the 8 company assets that would necessitate an emergency intervention. The expert hub could be available 24/7 at the headquarters or on-call for emergency consulting. The process of the control room for the 2nd and 3rd shifts is illustrated in Figure 64.

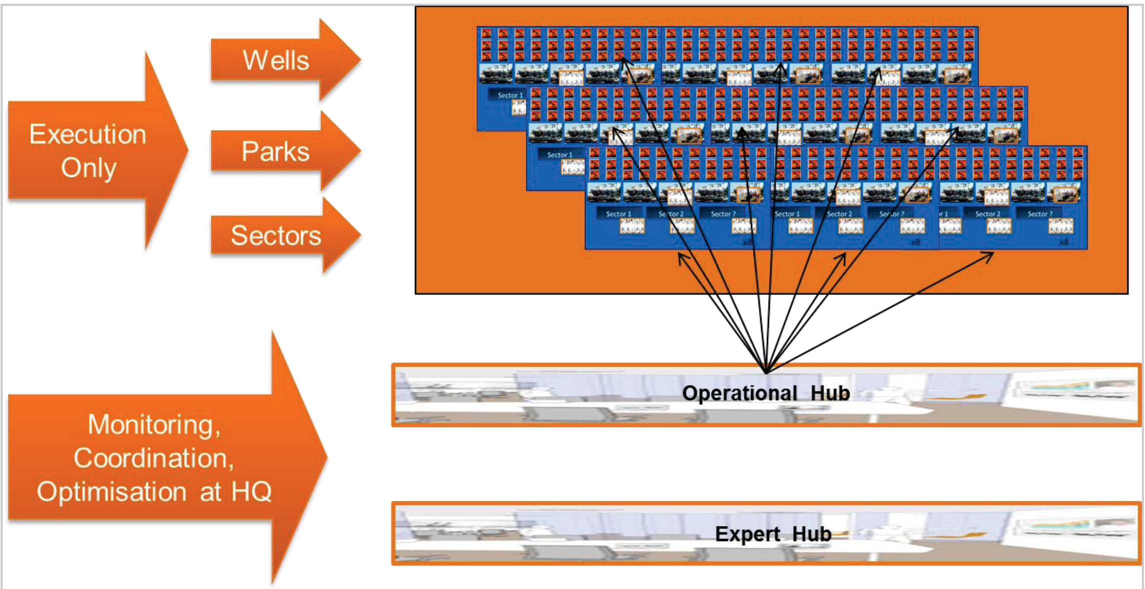

Figure 64: Control room vision for the 2nd and 3rd shifts

The drivers of installing control hubs in the company now are to align the organization to make the most of the new technology already installed, to re-prioritize work for the management based on monitoring results and to maintain competency despite aging workforce.

The features of control hubs that yield benefits are the following:

- Visualization available at all levels that need to collaborate
- Visits to facilities by exception, not routines
- Communication network to allow real-time re-routing of staff based on changing priorities
- Consistent approach across Operations and Maintenance
- High reliability of unmanned facilities

Recommendations

- Pilot Control Hubs should be deployed in those Assets with the highest levels of automation then a roll-out should be made to the rest of the assets as automation develops
- Expert Hub should be deployed for a selected process first then replicated for others

People

- Ensure engagement at all levels around Digital Oilfield concepts
- Ensure people understand what is different between the real-time way of working (reacting to events over minutes/hours) that the automated data acquisition enables versus the current planned way (reacting over days/weeks)
- The key to the success of Operational and Expert Hubs is the building of trust between the hub teams and the field operations teams.
- The Hubs must have the empowerment to make decisions within an agreed boundary without escalation to management
- Operational hubs should be staffed with people from Operations who know the local equipment and the people best

Processes

- The processes must be modified to be collaborative (i.e. real-time, multi-location, multi-discipline) in order to get the most from the technology spend
- A process of Alarm Management and Response will need to be developed with the levels of escalation set quite high to allow decisions to be made quickly
- Processes should be developed with learnings from actual events
- The first step is to have the Operational Hubs focusing on primarily Alarm Handling and Response, however greater value can be obtained through making the use of real-time data to make production optimization and maintenance prioritization decisions faster in a hub environment rather than through the traditional line management route. This will require production and facility engineers sitting alongside the monitoring staff and moving to management-by-exception.

Technology

- The current level of technology allows for the start of a Control Hub, integrating more automated facilities can be done with time
- Real-time business KPIs visualization should be a primary focus
- Simplify and standardize existing data capture/communication to allow the Hub to function across yet-to-be-automated equipment (e.g. only send exception results (by radio/text) and not full reports)
- Adding a control capability to the automation will greatly improve the ability to eliminate unnecessary operations work and associated human errors

Organization

- The company has a complex organization managing a large number of facilities across a geographic area with limited infrastructure
- Moving as much non-execution work up from the Production Sector level up to Asset Level will reduce the ‘office’ work at sector level allowing more time to be hands-on
- There are areas where work can be eliminated to allow reprioritization of work driven by the real-time data monitored (e.g. less routine visits, less status reporting)
- If 3 shifts are needed for the Control Hub, an assessment should be made whether the OPEX saving will outweigh the production loss events that can be resolved during the night shift

9 KPI monitoring to show value added by DOF approach

The following benefit categories and their source KPIs are to be monitored in order to demonstrate the benefits brought by a digital oilfield approach and remote monitoring. Following is a list of benefit categories and their source:

- **Production Increase** due to
  - overall optimisation of the well process
  - reduced unscheduled deferment
  - faster well start-up
  - faster corrective response to low and off deferment
  - lower incident response time and elimination of travel delays
- **CAPEX Saving** due to
  - eliminating unnecessary facilities and process simplifications (e.g. separators for well tests, less personnel amenities at remote sites)
  - less severe safety system requirements at remote, unmanned facilities
  - advanced data analytics used to proactively detect equipment failures by more effectively planning maintenance
- **OPEX Decrease** due to
  - manpower savings
  - less travel and less logistics such as food, catering and cleaning at remote sites
  - reduction in field work force due to remote start-up, shut down and adjustment of wells and process parameters
- **Production Efficiency Increase** due to
  - continuous surveillance and optimization by expert staff
  - faster response to changes in product demand due to fluctuating market empowered by the ability to optimize asset performance from reservoir to commercial market – not possible previously using the old manual mode of operation
  - operators and engineers seeing the same data on the same screens in the same format and in the same context enabling more efficient discussion and improved problem understanding and consequently better decision making
  - isolated, local analysis and decision making (field, sector, asset) replaced by centralized control with a comprehensive overview of the entire production process and the ability to respond faster and more effectively to arising process events, abnormal operations and changing market demands
  - dispersed data changed by centralized information giving the ability to better integrate, retain and distribute knowledge or experience
- **HSSE Risk Decrease** due to
  - reducing staff contact to travel hazards (e.g. driving)
  - reducing staff contact to process hazards at the well site (opening/closing valves on high pressure pipes and exposure to toxic chemical e.g., H_2S)
- **Staff Productivity Improvement** due to

- less time spent travelling
- less time spend on data searching, data collection, filtering and formatting resulting in more engineering time

- **Enhanced energy efficiency** due to
  - GHG (greenhouse gases) emissions reduction due to less travel and enhanced process efficiency
  - Electricity consumption decrease in wells

A list of the source KPIs attributed to their benefit category and connected the unit of measurement is presented in Table 22. Some of the KPIs can be integrated into multiple benefit categories (e.g. electricity consumption can be seen as a KPI in both the Production Efficiency and Energy Efficiency).

Table 22: Benefit categories of DOF approach, KPIs to be monitored, and their unit of measurement

Benefit Category	Key Performance Indicator (KPI) to be monitored	Unit of measurement
Production increase	Production Level	bbls/day
Production Increase	Unscheduled Deferments	bbls/day
Production Increase	Time to Well Start-up	hours
Production Increase	Corrective Response Time to Well Low and Off Deferment	hours
Production Increase	Incident Response Time	hours
Production Increase	Deferment Time due to Wellsite Travel	hours
CAPEX Saving	Facilities CAPEX per process	€ / process
CAPEX Saving	Broken equipment replacement CAPEX	€
OPEX Decrease	Manpower savings	cumulative worked hours/day
OPEX Decrease	Cumulative Staff Travel Distance	km/day
OPEX Decrease	Logistics Cost	€/day

Production Efficiency Increase	Time from Problem Start to Detection	hours
Production Efficiency Increase	Time from Problem Detection to Corrective Action being applied	hours
Production Efficiency Increase	Electricity Consumption	W / bbl
Production Efficiency Increase	Pumping Efficiency	%
Production Efficiency Increase	Production Offset from Market Demand	bbls/day
Production Efficiency Increase	Control Hubs Average Time to Decision	hours
Production Efficiency Increase	Control Hub Decision Success Rate	%
Production Efficiency Increase	Control Hub Decision Transparency	% of stakeholders
HSSE Risk Decrease	Staff Travel Incidents	# / year
HSSE Risk Decrease	Well Site Incidents	# / year
Staff Productivity Improvement	Value adding decisions (V.A.D.)	# of V.A.D./month
Enhanced Energy Efficiency	GHG emissions due to travel	kg CO2/day
Enhanced Energy Efficiency	Electricity consumption	W / bbl

10 Conclusions and Recommendations

The onshore producing wells in OMV Petrom are part of brownfields and have generally low production levels. In order to manage production losses optimally, the concepts of a digital oilfield approach must be integrated and applied on the company level. Although adopting this step-change requires additional investments, they are demonstrated to be paid-off by the incremental production generated on well level and the other benefits of a digital oilfield described in this thesis.

Infrastructure is a key concern throughout company's domestic assets, and additional technology must be retrofitted to existing systems. The reliability of the infrastructure is also causing production losses (e.g. electrical breaks). My recommendation is that part of the focus should also go into consolidating the existing systems, to better lay the groundwork for future upgrades.

People in the company need to understand the value added by an integrated approach and adapt to the change, and new processes must be developed to integrate the new technology.

Remote monitoring should be implemented in a centralized way, with control hubs that integrate people, processes, technology, and information and enable a smarter way of producing hydrocarbons.

By adopting a digital oilfield approach, the production losses recorded in categories like 'weak' wells, 'decreased flow' wells and 'watercut increase' wells can be reduced. These loss categories have been correlated with other production loss categories like 'pump failure' and 'well downtime' so it has been demonstrated that beneficial consequences also occur in other areas than production increase (reduced maintenance, OPEX decrease, production efficiency increase, HSSE risk, and enhanced energy efficiency).

Progress has been made in adopting the new way of thinking and doing business in the company, and part of technology is deployed and ready to be used. Several DOF Pilots are underway and expecting to see results, while new processes are being developed to include the new technology, and people are trained to develop understanding and expertise.

The current times of low oil price should not be considered as a reason to downsize investment into digital oilfield projects, but as an ideal time to optimise operations in an increasingly tough environment.

My final recommendations for managing production losses in OMV Petrom are to consider the implementation of real-time flow metering in 'weak' wells and 'decreased flow' wells, and a selective implementation of flow metering with watercut sensors in those 'watercut increase' wells which currently have a production loss from potential high enough to outweigh the initial investment.

As for installing fault current indicators on electrical lines to reduce well downtime and consequently production losses, the project would be economic only at oil prices higher than

60$/bbl. However, as some of the electrical lines are state-owned, I recommend the company should start negotiating with the state in order to acquire a discount on the initial investment, which might make the project economical even at lower oil prices. The reasoning behind a discount is that such an investment would not only benefit the company, but the other users of the electrical power grid too (e.g. locals, institutions).

Remote start-up of the automated wells after the occurrence of electrical breaks is the last production loss management approach I recommend, and potentially the one with the highest benefit to cost ratio. A reprogramming of the automation systems available on wells, done by the maintenance and IT staff, should include a procedure where the wells restart on a pre-set time interval after the electrical power breaks are over. The fact that the intervention is done with existing staff and no extra capital investment involved should lower total costs considerably, while the benefits have been quantified.

The applicability and success of the above recommendations is yet to be tested, and I hope the continuous improvement culture that the company follows will allow the achievement of an optimised and responsible production level.

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