Master Thesis

THE ECONOMIC VALUE OF TECHNOLOGY FOR LIFTING HYDROCARBON FLUIDS IN MATURE FIELD OPERATION

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Leoben, 11.06.2013

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Kurzfassung

Wirtschaftlicher Erfolg ist eines der wichtigsten Themen im heutigen Öl- und Gasgeschäft (nach HSE). Wirtschaftliches Arbeiten wird immer schwieriger in dieser Branche, unabhängig von der Unternehmensgröße. Die Ära der Großen Öl- und Gas-Funde ist vorbei. Auch die Herausforderungen für Feldes Entwicklungen steigen aus geologischen, politischen und finanziellen Gründen. Diese Herausforderungen können zu einem gewissen Maß von der steigenden Preisentwicklung abgefangen werden. Deswegen sind die Unternehmen gezwungen ihr Handeln ständig zu verbessern. Generell gibt es 3 Möglichkeiten um den wirtschaftlichen Erfolg zu garantieren und den Fortbestand des Unternehmens zu sichern:

- Exploration neuer Felder
- Steigerung der Produktion
- Reduktion der Ausgaben

Die Entwicklung alternder Lagerstätten ist eine attraktive Möglichkeit um wirtschaftlichen Erfolg zu steigern. Ungefähr 40 % der heutigen Öl- und Gasproduktion wird aus solchen Lagerstätten generiert. Große internationale Ölgesellschaften geben alternde Felder vielfach an kleinere Ölgesellschaften ab, da die großen Gesellschaften nur noch eine marginale Wirtschaftlichkeit sehen, wo hingegen die kleineren noch eine lange wirtschaftliche Förderperiode erreichen können.

Alternde Lagerstätten bieten eine großartige Möglichkeit für kleine Unternehmen, wenn Knowhow und Technology vorhanden sind. Erfolge können durch richtigen Einsatz von neuer Technologie relative schnell erzielt werden. Eine neue angepasste Technologie reduziert effektiv die Anzahl der Fehler in einem Bohrloch. Dies erfolgt durch den Schutz von vorhandenen Equipment und Installation von verbesserten Materialien. Außerdem resultiert der Einsatz von neuer Technologie in Steigerung der Produktionsraten von Öl und Gas, Zufluss Verbesserung und Steigerung der Sonden Laufzeiten. Mit neuer Technologie können zwei der vorhererwähnten Punkte erfüllt werden (Reduktion der Ausgaben und Steigerung der Produktion).

Die Anwendung neuer Technologien ist immer mit Investitionen verbunden. Bei intelligenter und richtiger Integration und angepassten Einsatzplan können die Investmentbeträge aus dem vorgeschriebenen Budget generiert werden, ohne zusätzliche finanzielle Mittel in Anspruch zu nehmen.

In dieser Arbeit wird der Einsatz verschiedener Technologien anhand eines realen Feldes der Firma RAG technisch und wirtschaftlich bewertet. Es handelt sich hierbei um die Felder in Zistersdorf. Der wirtschaftliche Erfolg des Einsatzes der verschiedenen Technologien wird mithilfe von Einnahmen und Ausgaben Analyse, Analyse der „Workover“, Analyse des Equipments und Analyse der Verfügbarkeit der einzelnen Sonden durchgeführt.

Abstract

Economic success is the most important issue (after HSE) in today´s oil and gas industry (exploration and production business). This issue is becoming more significant for all sizes of companies working in this industry. The era of major exploration success with the discovery of huge fields is over. Additionally challenges to field developments are increasing rapidly, due to geology, politics and finance. These challenges can be cushioned somewhat by price development; nevertheless companies are forced to improve their operations and business development strategies. There are three possibilities to improve economic success and guarantee continuation of business:

- Exploration for new fields
- Expenditure reduction
- Production increase

The development of mature reservoirs is a possibility to increase the economic success. International oil companies often sell mature fields to smaller independent national companies. Whereas the international companies usually generate marginal profits, the smaller companies foresee a longer economic production period.

Application and investment in new technologies provides a great opportunity to improve economic success, especially in mature field operations. Today approximately 40 % of world hydrocarbon production is generated from mature fields. These mature fields are very sensitive to poor decisions, because most of them are already managed close to their economic limit. Younger fields are much easier to produce and margins are much higher, but massive investment is required. Furthermore the risk associated with exploration is much higher.

If knowhow and proven new technology are available, mature fields provide great opportunities for small companies. With the correct implementation of proven new technologies several positive impacts on overall mature field operation can be achieved. In the first instance failures of downhole systems can be reduced, through protection of given equipment and selection of more suitable materials and equipment. The result is a reduction of expenditure related to workover operations and replacement of failed equipment. A further outcome of new technology implementation is an increase in oil and gas production through improvements in inflow performance and increase in run time of wells. Thus two of three possibilities mentioned above can be achieved by the consequent implementation of new and proven technology (expenditure reduction and production increase).

Implementation of new technology is associated with investment. The amount of investment required can be generated out of a given budget, without the need for any additional funding.

Furthermore after a certain period of time the expenditure level can be reduced and additional cash flow for the company is generated. This is only possible with a well thought out plan for the implementation and monitoring of the application of new and proven technology in the field.

This thesis presents technologies used at RAG E&P Company to operate their mature fields and proves the economic value and success with detailed analysis of workover operations, equipment failures, availability of producing wells, marginal cost, production decline, expenditure and income.

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Abbreviations

A	Area
AC	Alternating Current
ALS	Artificial Lift System
API	American Petroleum Institute
bbl	Barrel
B_g	Gas Formation Volume Factor SCF/CF
BHP	Brake Horsepower
B_o	Oil Formation Volume Factor RB/STB
BTU	British Thermal Unit
CAPEX	Capital Expenditure
cf	Cubic Feet
CF	Cash Flow
CNG	Compressed Natural Gas
Cr	Chrome
CSS	Ceramic Sand Screen
cum.	Cumulative
deg	Degree
DROI	Discounted Return on Investment
E	Recovery Factor, Fraction
E&P	Exploration and Production
ECRR	Electronic Controlled Rod Rotator
EMF	Electromotive Force Series
EOO	Economics of Operation
EOR	Enhanced Oil Recovery
ESP	Electrical Submersible Pump
FBZ	Förderbetrieb Zistersdorf
ft	feet
GOR	Gas Oil Ratio
GRR	Growth Rate of Return
h	Thickness
HSF	High Surface Finish
i	Interest, discount rate
ID	Inside Diameter
IOR	Improved Oil Recovery
IPR	Inflow Performance Relationship
IRR	Internal Rate of Return
m^3	Cubic Meters
Mo	Molybdenum
MTBF	Mean Time Between Failure
N	Nitrogen
NCF	Net Cash Flow
Neg.	Negative
NPV	Net Present Value
OD	Outside Diameter
OGIP	Gas In Place
OOIP	Original Oil in Place
OPEC	Organization of the Petroleum Exporting Countries
OPEX	Operational Expenditure
P	Pressure
ϕ	Porosity, Fraction
PCP	Progressive Cavity Pump

PI	Profitability
PLT	Poly Lined Tubing
PO	Payback Period
Pos.	Positive
ppm	Parts per Million
PPP	Petroleum Production and Processing
PV	Present Value
ROI	Return on Investment
ROR	Rate of Return
RT	Run Time
SCADA	Supervisory Control and Data Acquisition System
SCC	Stress Corrosion Cracking
scf	Standard Cubic Feet
S_o	Oil Saturation, Fraction
SPM	Strokes Per Minute
SRP	Sucker Rod Pump
SSD	Sliding Side Door
SSiC	Sintered Silicon Carbide
STB	Stock Tank Barrel
S_w	Water Saturation, Fraction
t	Tonnes
T	Temperature
V	Volume
VSD	Variable Speed Drive
WTI	West Texan Intermediate

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1 RAG – The Company

RAG is a small Austrian company founded by Socony Vacuum Oil Company (today Exxon Mobil Corporation) and N.V. de Bataafsche Petroleum Maatschappij (today Royal Dutch Shell plc.) in 1935. At the beginning of company´s history production was mainly generated out of the Vienna Basin, which is one of the largest oil and gas producing areas in middle Europe.

During World War II oil production in Austria had a strategic role for Germany and the production was increased to an annual rate of 1.5 million tonnes in 1944. Austria was then the third largest oil producer in the world. After the end of the war, the RAG concession being in the Russian Zone was administrated by Russia.

After the signing of the Austrian State Treaty the legal situation changed and the area of Zistersdorf was returned to the Austrian administration. Additionally RAG had the right to explore for oil and gas in Upper Austria, which later became the main focus of RAG. Today a large portion of oil and gas production in Austria is coming from that region.

The company is working successfully in various petroleum segments, with very reliable national and international partners:

- Exploration
- Drilling
- Production
- Gas storage
- Geothermal energy generation
- Petroleum consulting
- Technology development

Due to the nature and maturity of the RAG fields engineers are forced to develop new techniques and technologies to operate fields in an economic way and increase the recovery factor. In the last two decades technology and knowhow has increased significantly resulting in the developed of a number of new petroleum production equipment, especially adapted for mature field production. These achievements helped the company to perform very well and generate a permanent positive cash flow.

As a company, RAG has a very considerable involvement in the development of new technology and further innovations will be forthcoming in the near future. This will provide a good possibility to operate joint venture mature fields nationally and internationally. Furthermore this knowhow and technology will create a very interesting segment as a petroleum consultancy, especially for mature field development and operation.

2 Technology Installed and Operated in Operational Center Zistersdorf

The operation center Zistersdorf (FBZ) consists of two of the oldest oil fields in Austria. First production started in 1937. In total more than 600 reservoir compartments have been defined in the area of Zistersdorf. Due to the maturity of the fields, challenges of economical production have increased and RAG has developed new technologies to guarantee the economic success of these mature fields.

IOR (**I**mproved **O**il **R**ecovery), MTBF (**M**ain **T**ime **B**etween **F**ailures) and the economics of operation are three major topics RAG is confronted with. Technologies which have been applied in operational center Zistersdorf are discussed and presented in this chapter. Some of those presented technologies are industry standard and others are RAG own developments or developments due to cooperation with other companies. In chapter 3, the overall economic value of the described technologies is discussed and presented in detail.

2.1 Electrical Submersible Pump (ESP)

To introduce and explain the main components of an electrical submersible pump a conventional ESP installation is shown in Figure 1. This configuration is the most commonly used in today´s oil and gas industry. The foot print of this type of installation is smaller compared to other lifting systems.

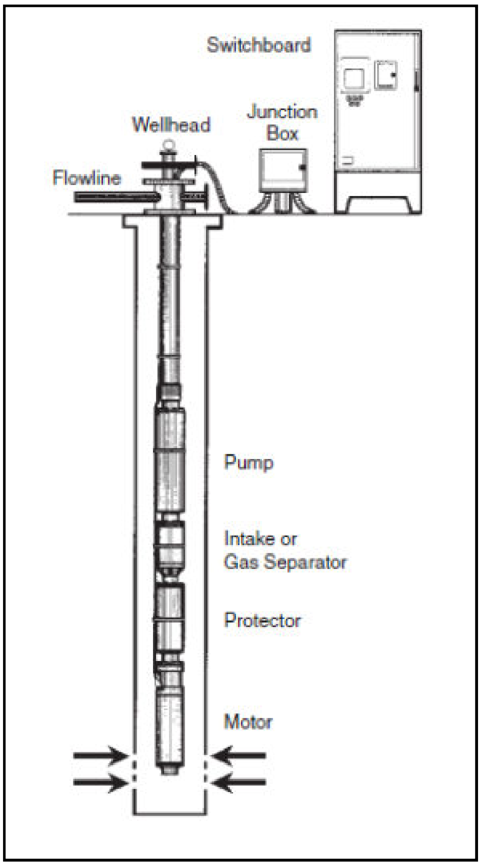

Figure 1: Conventional ESP installation. (Takacs, 2009, Page 52)

2.2 Motor

The motor is the driving force, which rotates the subsurface pump. The motor is supplied with a three phase alternating current (AC) via a cable from the surface. During operation heat is generated in the motor windings. This heat generated can lead to failure of the equipment, when a critical temperature is exceeded. Cooling of the motor is provided by surrounding wellbore fluids flowing past the motor to the pump intake.

Flow rate and position of motor (should be centralized in the wellbore) play a major role in ensuring sufficient cooling. Monitoring the temperature is very important to avoid failure of equipment and furthermore to avoid costly workover operations. The main components of an ESP motor are shown in Figure 2. Other than most companies; RAG does not monitor temperature; but just volts and amps on a strip recorder in operational center Zistersdorf. This has proven to be sufficient in this kind of operation.

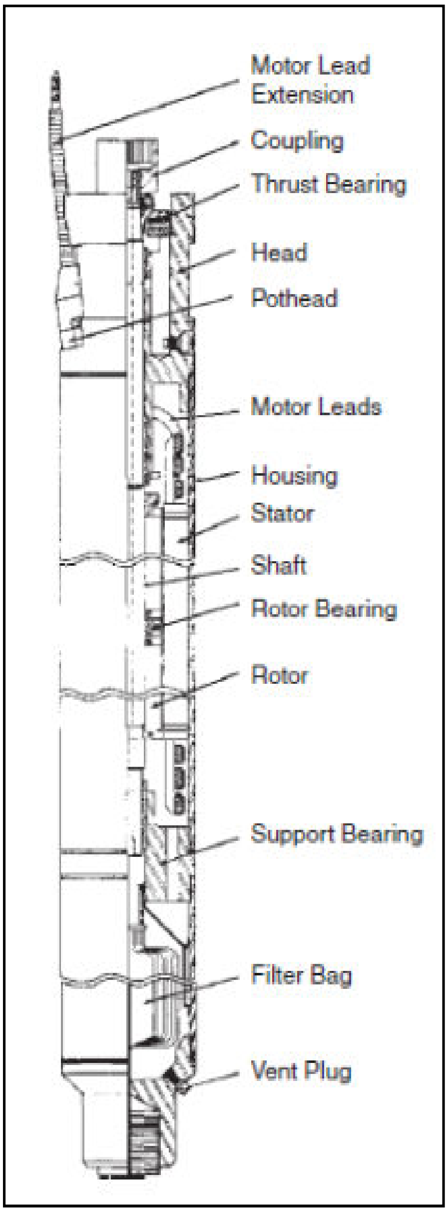

Figure 2: Main parts of ESP motor. (Takacs, 2009, Page 67)

2.2.1 Protector

This device is positioned between motor and pump (or gas separator if attached to pump intake) and has several functions to fulfill:

- Protect the motor from axial loads, which would act on the shaft of motor during operation. This could lead to a damage of motor through abnormal wear and compression force.
- Allow the expansion of dielectric high quality oil, due to the fact that the housing of the motor is not completely sealed. This avoids a burst of the motor housing caused by expansion of the oil as the temperature increases during the operation of equipment.
- Equalize pressure between inside of the motor and well bore, to avoid leakage in both directions (inside←→outside).
- Isolate dielectric high quality oil of the motor from surrounding well bore fluids.
- Is the connection between motor and pump.

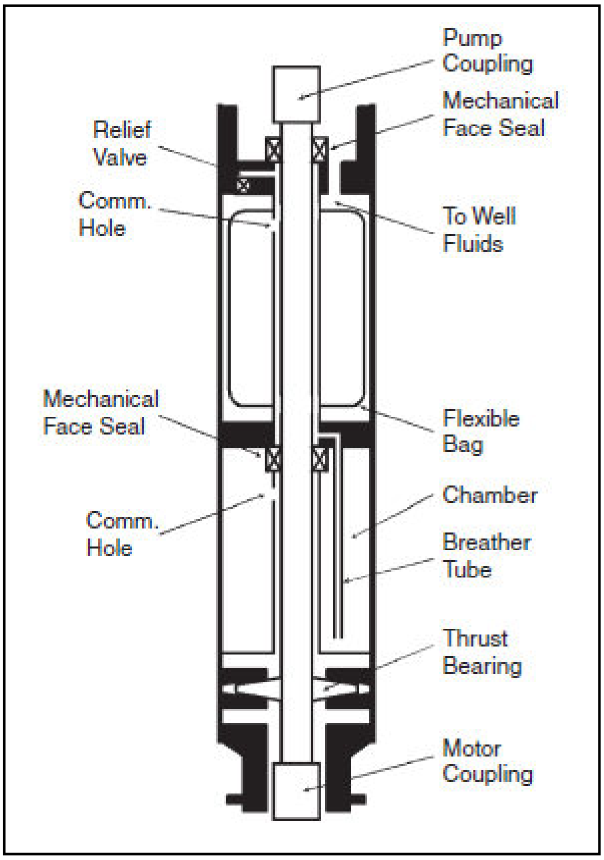

Figure 3: Schematic drawing of an ESP protector. (Takacs, 2009, Page 87)

2.2.2 Gas separator

The operational principle of this equipment is similar to that of a centrifuge, which uses density difference of media to cause separation of media with different densities. The main function is to transport wellbore liquids into the pump and to avoid the intake of free gas as shown in Figure 4.

Free gas that enters the pump has several negative impacts on operation:

- Head pressure developed by the pump is reduced, which leads to a low overall efficiency of operation.
- Output of the pump fluctuates and can cause major damage to the equipment.
- Gas lock can occur, which causes total damage of the pump (no fluids produced; gas is compressed and decompressed in the pump).

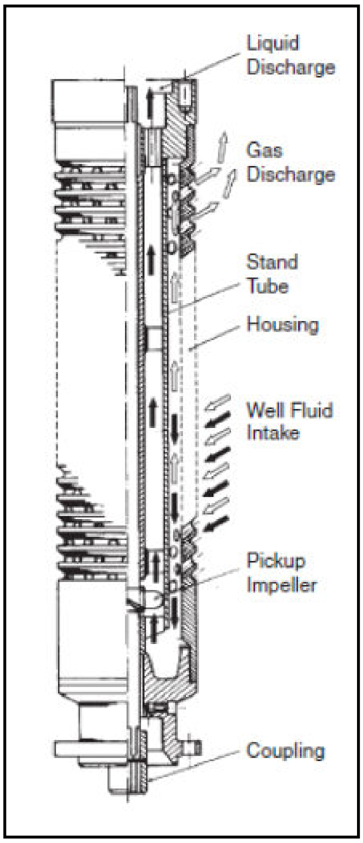

Figure 4: Construction of a reverse flow gas separator. (Takacs, 2009, Page 101)

2.2.3 Pump

The components and a cross section of the pump are shown in Figure 5. The operational principle of a submersible pump is to subject fluids to high rotation speed, created by the impeller and thus great centrifugal forces. Fluids enter the diffuser and kinetic energy is converted to pressure energy. A major point which has to be considered in the design process is the number of stages required, to lift the fluids to the surface. The pump capacity is dependent on several parameters:

- Speed of rotation
- Diameter and design of impeller
- Head pressure against which the submersible pump has to operate
- Properties of produced fluids
- IPR, depending on the gas amount

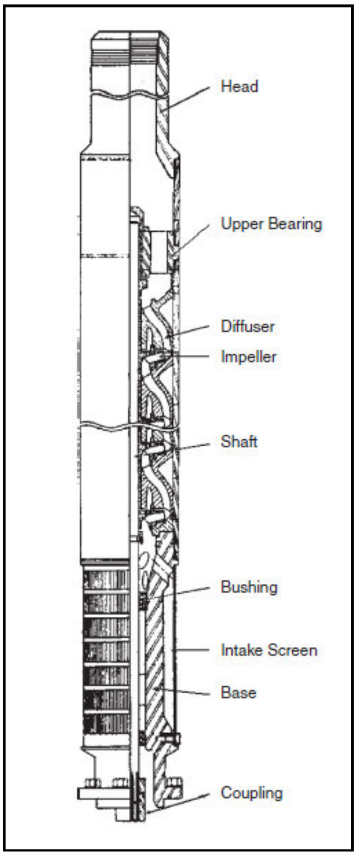

Figure 5: Main parts of an ESP pump. (Takacs, 2009, S. 54)

2.2.4 Power Cable

The main function of the cable is to provide the motor with three phase AC electric power from the surface transformer. The cable is installed along the tubing and has to be resistant to initial and future well bore fluids and gases. Selection of cables is critical, because they are very costly and in addition they are one of the most sensitive components of the system, such as cable splice and socket connections. Basically there are two different types of cables. Both cables shown below have a metal armor on the outside, which acts as a protection from mechanical damage, during running and pulling operations. The main difference in the cables is the shape and location in the well where they are installed.

- **Round cables**: Are banded to the tubing from the wellhead to just above the ESP. They need more space due to their geometry (outside diameter).

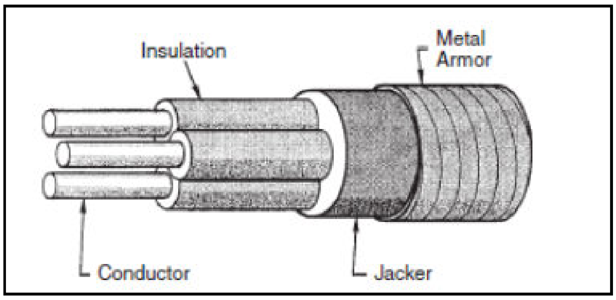

Figure 6: Construction of ESP round cable. (Takacs, 2009, Page 105)

- **Flat cables**: This type of cable is used where annular space or clearance is limited for example along the ESP.

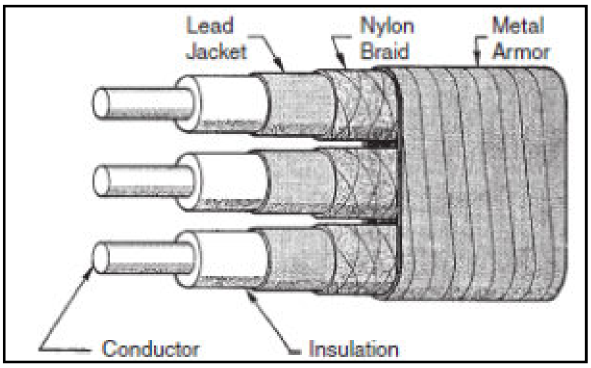

Figure 7: Construction of ESP flat cable. (Takacs, 2009, Page 105)

2.2.5 Wellhead

The wellhead has two main functions to provide. The first is to bear all the subsurface loads e.g. tubing weight, subsurface pump weight and fluid column weight. The second is to create a seal for the tubing and the power cable, such that no gas or fluids can escape. There are various solutions available on market as shown in Figure 8. The most important point to consider in the selection process is the connection point and the pass of the power cable. A perfect seal has to be secured.

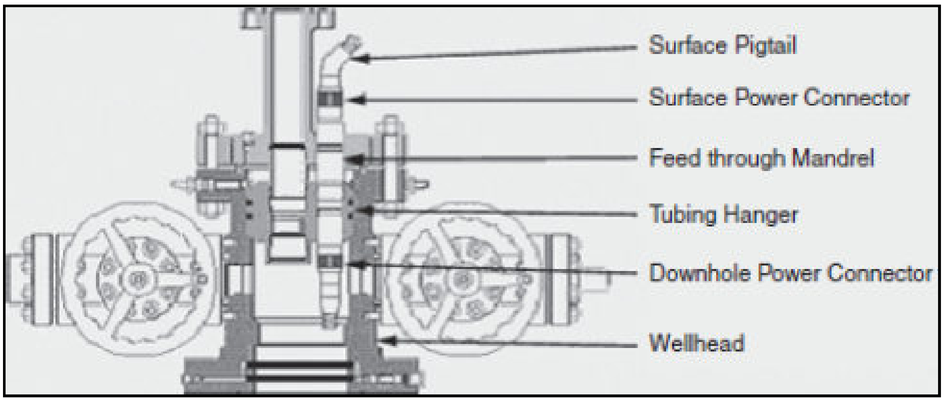

Figure 8: ESP Wellhead with power connectors. (Takacs, 2009, Page 114)

2.2.6 Junction Box

The junction box is the connection between the cable coming out of wellhead and the cable leading to the switchboard. It should be located at a sufficient distance from the wellhead to be outside of the hazardous area. The junction box is a ventilated and weather proved enclosure. It has three main functions:

- Providing electric connection between downhole and surface cable.
- Ventilation of any wellbore gases, which might migrate along the power cable.
- Test point for downhole equipment (electricity supply).

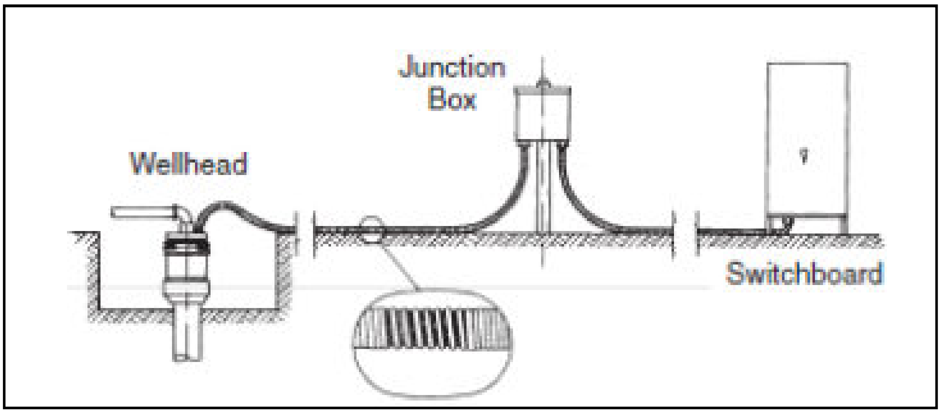

Figure 9: Surface arrangement of an ESP installation. (Takacs, 2009, Page 115)

2.2.7 Switchboard

The switchboard is the controlling device of the ESP. These vary in size, design, power rating and function. Normally they work at a fixed frequency. The main functions of this equipment are:

- On / Off switching of the ESP equipment
- Protection of surface and downhole equipment from over-loading, under-loading and unbalanced electric currents
- Monitoring and recording of operational parameters
- Back Spin Relay, used to delay restart until counter rotation, due to falling fluid level in tubing, has ceased
- Test point for downhole equipment (electricity supply)

2.2.8 Transformers

They are used to provide the required voltage to operate the electrical submersible pump. The operational voltage of ESP motor is in the range of 250–4000 volt. This type of equipment is mostly oil filled and self-cooling. Voltage level and power ratings are the selection criteria of a transformer. Surface voltage required is the sum of voltage loss along the cable and the required motor voltage.

2.2.9 Optional Downhole Equipment

Cable Bands

Cable bands are used to latch power cable to the tubing to avoid mechanical damage of the cable during running and pulling of the ESP and carry the weight of the cable. They have a recommended spacing of 15 ft.

Check Valve

A check valve can be installed two to six tubing joints above the pump. RAG usually does not use this type of equipment. This equipment has three main functions to fulfill:

- Stop back spin caused by a falling fluid column in the tubing string, when the pump stops. Thus reverse motion of the motor is avoided.
- Avoid settling out of produced fines from the fluid column directly on top of the pump.
- Ensure a full tubing string above the valve for starting up operation of ESP.

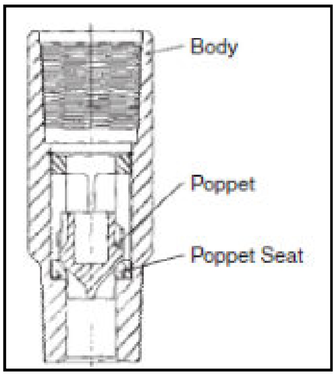

Figure 10: Main parts of check valve. (Takacs, 2009, Page 111)

Drain Valve

The main function of the drain valve is to equalize pressure between tubing and casing-tubing annulus by opening a port. Thus during pulling operations the tubing is almost dry, which increases the safety of the operation (dry rig floor). This equipment is activated by shearing off the break-off plug as shown in the figure below.

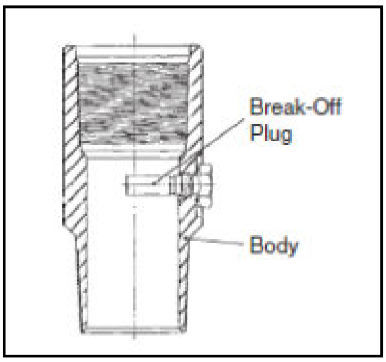

Figure 11: Main party of drain valve. (Takacs, 2009, Page 112)

Centralizers

These are used to centralize the ESP in the well bore, to achieve the best cooling of the motor and prevent mechanical damage to the cable.

Y-Tool

With this type of equipment the operators have full access to the formation below the ESP, without pulling the tubing string and ESP out of the well. Operations such as formation treatment (acidizing, fracturing), well completion (perforation of new zones) and logging can be performed in an economic and timely manner.

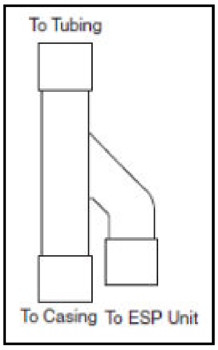

Figure 12: Schematic drawing of Y-Tool. (Takacs, 2009, Page 113)

Downhole Instrumentation

The downhole instrumentation devices are installed to obtain information on operating conditions and eventually to predict at an early stage problems that may occur in the future. This leads to more economic operation and to an increase of MTBF. Such instrumentation parameters listed below can be monitored:

- Pump intake pressure and temperature
- Motor oil and motor winding temperature
- Pump discharge pressure and temperature
- Vibrations and electrical current leakage

Sacrificial Anode

A sacrificial anode can be added to the ESP configuration, underneath the motor. The function is to protect the ESP from corrosion. Worthwhile mentioning that some vendors do not recommend a sacrificial anode for reasons RAG cannot follow.

Chemical Injection Line

A chemical injection line can be run together with the power cable to just below the pump intake. Chemical solutions can be injected to protect the tubing string from corrosion, scaling of paraffin and asphaltene.

2.2.10 Performance Curve of ESP

The performance of ESP´s is characterized by pump performance curves, which indicate:

- Head developed by one stage of the pump
- Efficiency of the pump
- The power (brake horsepower) required to drive the pump

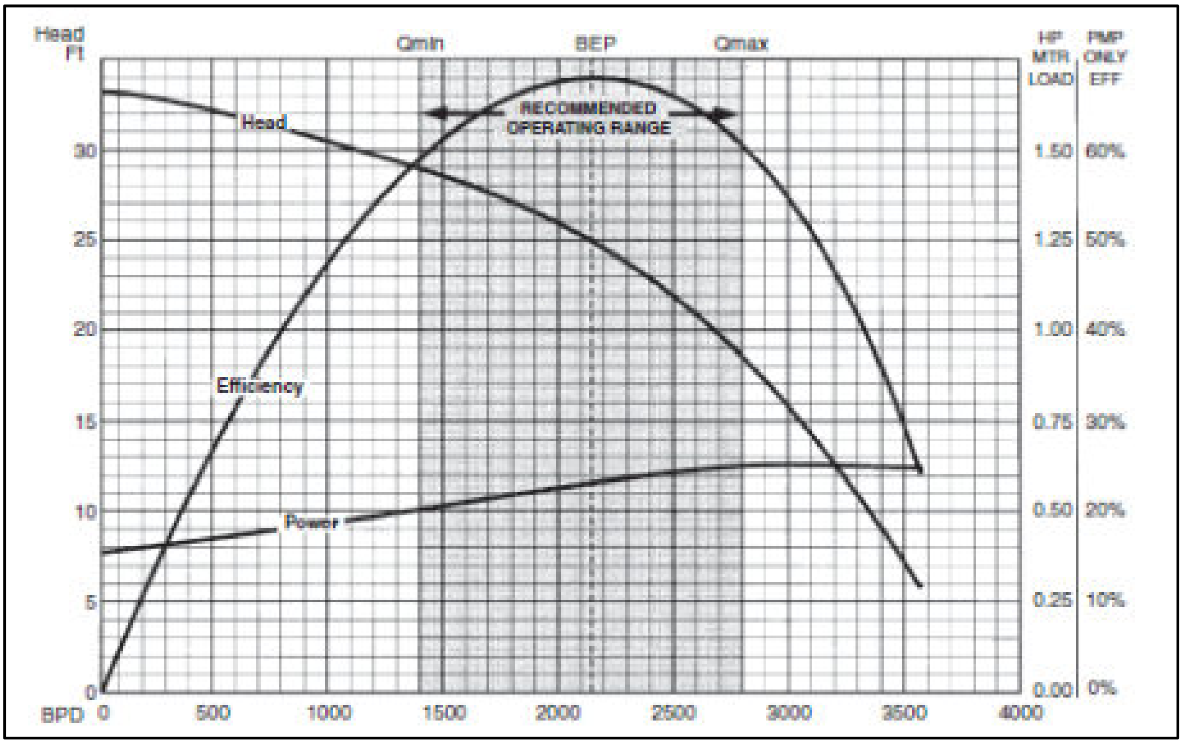

Figure 13: Typical ESP pump performance curve. (Takacs, 2009, Page 56)

The curves are gained by factory testing. These tests are carried out with freshwater and under fixed operating conditions:

- Operating temperature of 60 F or 15.5 °C.
- Constant rotational speed, usually 3,500 RPM for 60 Hz service.

When operating an ESP in the field the optimum operational range has to be determined. The recommended operating range is that in which the pump can be reliably operated. The best point is where pump efficiency curve peaks. The BHP (brake horsepower) curve shows the power required to drive the stage. For the required head and flow rate the number of stages can be determined.

To avoid abnormal wear of the equipment through up-thrust or down-thrust on the impellers, the pump should always be operated within the recommended operating range. It is noted that when operating at a low rate a high head can be achieved and vice versa high rates result in a low head and more stages.

2.2.11 Advantages and Disadvantages of an ESP

To select the appropriate lifting equipment reservoir properties, fluid flow, productivity index and technical capabilities of lifting equipment have to be determined.

Advantages

- Lifting large volumes of well fluids.
- Unobtrusive in urban locations. Footprint of an ESP is small and noise level is low compared to other artificial lift systems.
- Simple to operate and easy to install.
- Easy to monitor, due to surface installation of switchboard. All monitored parameters are collected and recorded in this device.
- Applicable offshore, due to small foot print, if power situation permits.
- Inhibition against corrosion and scale is easy to perform with chemical injection line.
- Unit lifting cost per barrel less than other lifting systems.
- Variable Speed Drive (VSD). With VSD an adaption of production and the control of dynamic fluid level can be easy achieved.
- Applicable in deviated wells.
- Very safe in operation.
- Deployment with coiled tubing is possible.

Disadvantages

- Impractical in shallow and marginal volume wells, due to high CAPEX.
- Workover rig is required to change downhole equipment.
- Tubular handling on rig floor is more difficult due to power cable.
- Cable problems in high temperature wells. The correct selection of the cable material is very important.
- Gas and solids production may cause damage to the pump. Knowledge of reservoir conditions is important.
- Selectivity of zones is limited, only possible with a tail pipe and Y-tool completion.
- Dog Leg Severity (DLS) must also be limited, to ensure save deployment of equipment without damage. In new development systems DLS can go up to 7 deg/100 ft.

2.2.12 Design Criteria of ESP

Before going into the design process of an ESP various parameters have to be determined:

- **Well data**: This includes general design of the well and historical data recorded.
- **Production data**: This includes information and parameters of produced fluids and pressure regimes present in different parts of the well, PI and IPR, temperature distribution within the well.
- **Well fluid properties**: This includes fluid specific parameters, which may have a major impact on design of the ESP.
- **Power source**: The supply and availability of energy to operate the ESP equipment.
- **Life-Cycle-Analysis**: An investigation of possible problems should be carried out to understand which challenges could occur after the installation of ESP equipment.
- **Economics**: CAPEX and OPEX.

Table 1 shows the different criteria.

Well Data	Casing size Pump setting depth History of treatments Well design (perforated, open hole, DLS)
Production Data	Well head tubing pressure Well head casing pressure Present production data Forecast production Produced fluids Static fluid level Static bottom hole pressure Bottom hole temperature Gas oil ratio (GOR) Water cut Temperature
Well fluid properties	Specific gravity of water Specific gravity of oil Specific gravity of gas Bubble point pressure Composition and properties of oil Composition and properties of gas Properties of formation water Salinity of formation water
Power source	Availability of energy Cost of energy Power source capability

Life-Cycle-Analysis	Solids Production Deposition of asphaltene and paraffin Corrosion Free gas Emulsion Bottom hole temperature Cable failures Scaling Separation Motor protection
Economics	CAPEX OPEX Hydrocarbon sells expectations

Table 1: Summary of design criteria for an ESP.

2.2.13 Application in Operational Center Zistersdorf

In total 3 ESP are presently installed in operational center Zistersdorf. One is installed in the Rag field at the well RAG-022. The other two units are operating in the Gaiselberg field, at GA-013 and GA-083. All units have a conventional configuration as presented in Figure 1 (see chapter 2.1).

No additional equipment for gas separation is installed downhole. Associated gas volumes produced from the various formations can be handled very well by the equipment. The ESP´s have shown good performance during operation. RAG proved run time of ESP of more than 1000 days.

2.3 Pumping Units and Sucker Rod Pump (SRP)

2.3.1 General

Beam pumping unit, operated sucker rod pumping systems constitute one of the oldest pumping systems known to the industry. These types of pumps have been used by the Chinese 3000 years ago. Over the years, the basic idea behind this invention has remained the same. Almost all modern pumping units convert rotational motion into reciprocal motion (up and down movement).

Pumping units can be classified into 4 major groups:

- Class I Lever system
- Class III Lever system
- Long stroke pumping unit
- Hydraulic pumping unit

The first two classes are the most commonly used in the E&P industry. The other two are used for special situations and applications. Figure 14 shows the basics of a beam pumping unit.

- **Prime mover (motor)**: Is the powering device of the system.
- **V-belt**: Creates the connection between prime mover and gear reducer.
- **Gear reducer**: Main function is the reduction of prime mover speed to desired pumping speed. This device also increases the torque provided.
- **Beam (pumping unit)**: Translates rotating motion into a reciprocating motion.
- **Horse head**: The geometry guarantees that the polished rod is always moving vertically through the stuffing box.
- **Stuffing box**: A seal for the wellhead and polished rod.
- **Polished rod**: The uppermost “rod” in the string has a special surface finish to seal against the stuffing box packing.

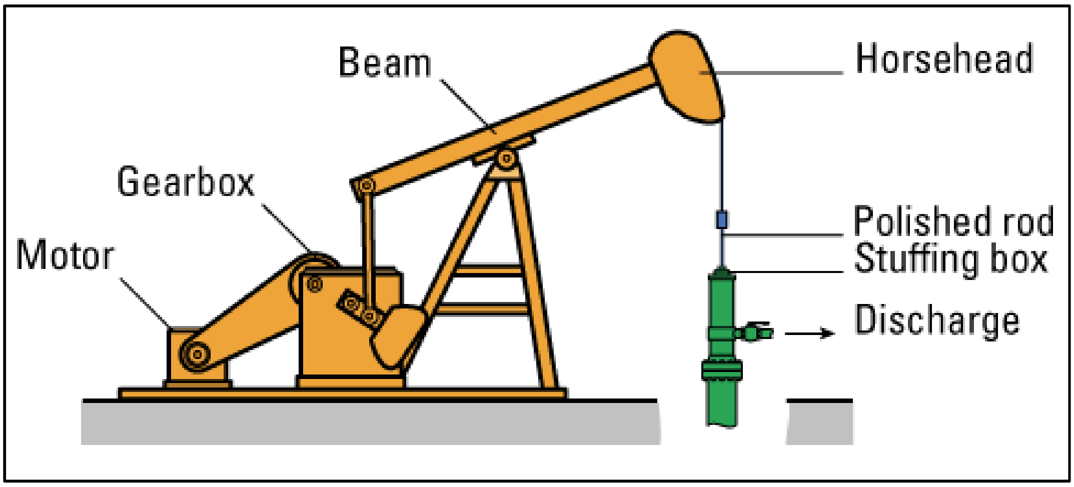

Figure 14: Surface parts sucker rod pump. (Schlumberger, 2012)

In Figure 15 the main parts of a subsurface sucker rob pump are shown and the working principle of the pump is illustrated:

- **Rods**: These transmit the reciprocating motion generated at the surface pumping unit to the subsurface pump.
- **Plunger**: This device is connected to sucker rods and contains the traveling valve.
- **Barrel**: Is a cylinder which contains the standing valve at the bottom.

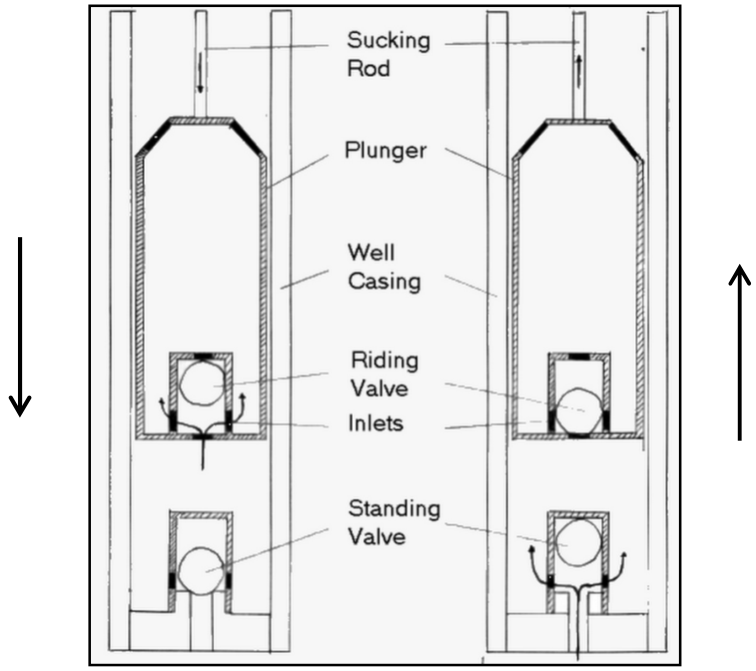

Figure 15: Parts and working principal of the subsurface pump. (Cechovsky, 2012)

2.3.2 Classification of Pumping Units

As mentioned before the main function of the pumping unit is to convert rotational motion of the prime mover to a reciprocating vertical motion. Counterbalance weights are used to act against the weight of the sucker rod string and the load of the fluid column and keep the whole system “balanced”. There are a number of designs, sizes and configurations available for pumping units. Selection is based on the specific requirements.

Class I Lever System

In this design “the samson-post bearing” is positioned in middle of the walking beam. Samson-post bearing takes all the load of the rods and the counterbalance weights. Two types of units are available, which mainly differ in position of the counterweights:

- **Conventional Crank-Balanced Units**: This design has adjustable counterweights, which are installed on the crank. This leads to a wide range of application in development of a field. The largest benefit of this design is its simplicity.
- **Beam-Balanced Units**: In this type of pumping unit, the counterweights are directly attached on the walking beam, to be precise at the end of it. Due to its construction, this type of unit is more sensitive to high pumping speeds. It is preferred for

applications with low pumping speed and small pump sizes. It´s ideal utilization is shallow reservoir production.

Class III Lever Systems

The pivot is positioned at the end of walking beam. The force coming from the prime mover acts between pivot point and horsehead. In this design category there are two subclasses. The main difference between class I and class III is the kind of counter force used to act against the weight of the rod string and fluid column.

- **Mark II Units**: The bearing is nearby the horsehead, often only some tenth of centimeters away. To create an out-of-phase condition between torque exerted by well loads and torque exerted by counterbalance weights the cranks are designed with an angular offset. This offset reduces problems associated with torque peaks, which leads also to larger maintenance intervals.
- **Air Balanced Units**: To counter the load of rod string and produced fluids an air cylinder is installed and acts against forces acting on the horse head. Operating air in the cylinder is provided by an air compressor controlled by a pressure switch. A big advantage of this design is the increased control of the counter force and the reduced foot print compared to other designs.

Long Stroke Units

The biggest advantage resulting from long stroke designs is the reduced cyclic loading, the stress comes from rod weight and fluid column weight. Additionally power requirement for operation is less compared to other types of pumping units, due to reduced pumping speed.

Hydraulic Pumping Units

The hydraulic pumping consists of two major components:

- **Tower**: This part contains a hydraulic cylinder to which the rod string is attached.
- **Power unit**: The prime mover, hydraulic system and controller are installed in the power unit.

Hydraulic lines form the connection between the two components. Noise and footprint is small and the mean time between failure is long, because there are less moving parts compared to other pumping systems.

2.3.3 Surface Equipment

Prime Mover (Motor)

For providing power to the system, two types of prime movers are commonly used:

- **Internal combustion engine**: The power source is of the engine is often natural gas (dehydration of water and removal of oil or sour gas components may be recommended). If there is no natural gas available, the engine can be powered with diesel, LPG, CNG and light-gravity crude oil.
- **Electric motor**: They are commonly operated by three-phase power. The alternative could be single-phase AC motors. They can be used on shallow wells. AC single phase motors are more expensive and less efficient compared to three-phase motors. DC motors are sometimes used to drive pumping units, but have disadvantages e.g. their inability to use electricity from utilities.

Gear Reducer

Main function of a gear reducer is to reduce the speed of a high-speed motor or engine at the input shaft to a lower rotational speed and with higher torque at the output shaft. Gear reducers offer mechanical safety by reducing the speed of the rotating equipment, thus helping to decrease the number of failures. In its most simple form the gear reduction takes place at a fixed transmission ratio.

Beam Gas Compressor

The main function of a beam gas compressor is to increase efficiency of the overall system. This equipment compresses gas drawn from the tubing casing annulus. Consequently gas pressure in the annulus is reduced, reducing backpressure acting against the formation. This also reduces the possibility of a gas lock within the pump. This equipment has two main functions to fulfill during operation:

- Reduce annular pressure, to avoid gas lock and optimize production.
- Compress produced gas to required pipeline pressure.

Due to the fact that annular gas is pumped into a flow line / pipeline system and not vented, revenues of the whole project are increased. There are two main classes of beam gas compressor:

- **Single acting** (one way operating) beam gas compressor, which only compresses gas during up-stroke or down-stroke operation. The best application for this type is a well with low to medium gas volumes.
- **Double acting** (two way operating) beam gas compressor, which works during up- and down-stroke; it is commonly used in wells with high gas volumes. The functionality of a double acting beam gas compressor is illustrated in Figure 16.

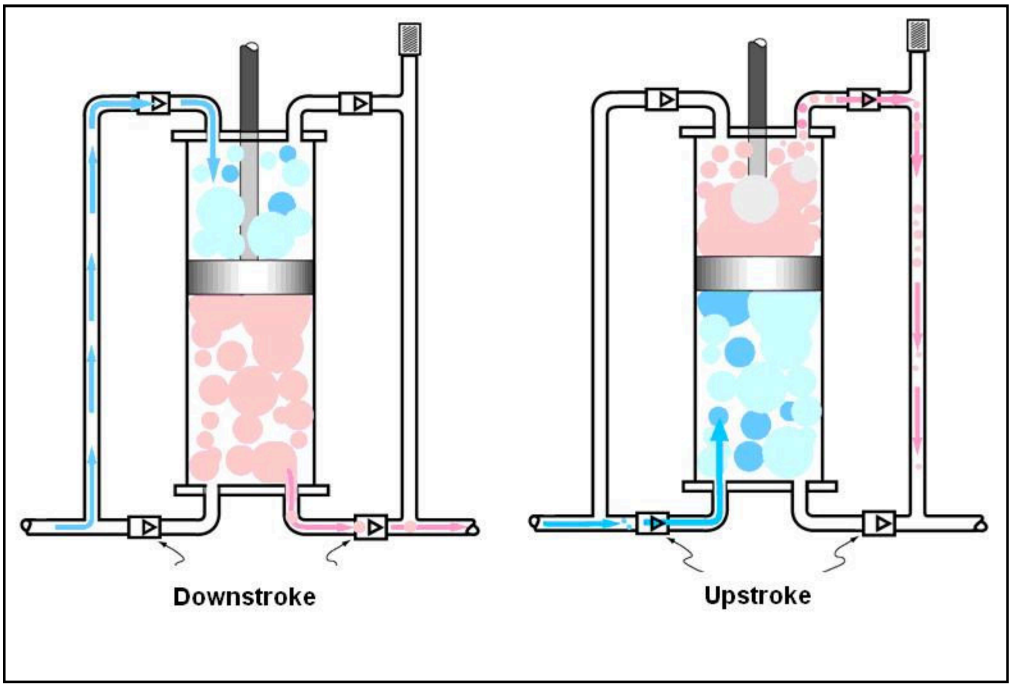

Figure 16: Operation of double acting beam gas compressor. (Cechovsky, 2012)

2.3.4 Subsurface Sucker Rod Pump Equipment

Pump

Rod pumps can be classified into three main types:

- **Tubing pump**: The barrel is attached to the tubing string and the plunger is attached to the sucker rod and run into the tubing in separate runs. These types of pumps are the largest. To service the equipment both rods and tubing must be pulled, resulting in higher workover duration and thus expenditure.
- **Insert pump**: Barrel and plunger are attached to the sucker rod and installed in one run. Downhole there is a seat (seating nipple) in the tubing for the barrel. This type of rod pump is easier to service. The biggest disadvantage is that it can only handle smaller volumes than a tubing pump.
- **Casing pump**: Barrel and plunger are attached to the sucker rod and installed in one run. Downhole there is a seat for the barrel positioned in the casing. For this design no tubing is installed. This type is not commonly used. Best applications are shallow wells with big production volumes.

“The working principle of the various types is basically the same. When the plunger is at its lowest position and upward movement just starts, a differential pressure is created across the traveling valve. The valve moves against a pressure called pump discharge pressure. This pressure is the sum of hydrostatic fluid column above valve, wellhead pressure and pressure losses within the tubing. This differential pressure causes the traveling valve to close, and a low pressure area is created below the plunger.

Therefore, a pressure differential acts on the standing valve. Higher pressure outside of the pump opens the standing valve and fills the void space within the pump chamber with fluid. This pressure is controlled by pumping fluid level (or dynamic fluid level), which reflects the drop of fluid level within the casing-tubing annulus during production. When the plunger reaches the top of the stroke and starts moving downwards, pressure inside the pump will exceed pressure outside the pump, thus closing the standing valve. As the plunger continues moving downwards, fluid is compressed, thus causing a pressure differential between inside of the pump and the production column above the pump.

With plunger travelling downward, pressure inside pump barrel causes a force, which opens the traveling valve. When this force is large enough to exceed the force pushing on the travelling valve ball from the fluid column above the pump, the travelling valve opens. As the plunger continues its downward motion, fluid is pushed through the travelling valve into the production column above the pump. When the plunger reaches its lowest position, differential pressure decreases and the travelling valve closes." (Cechovsky, 2012)

Sucker Rods

Sucker rods the connection between the subsurface pump and the pumping unit at the surface. The rods are produced in a length of 25 ft or 30 ft with API-standard diameters. To adapt the string to exact length required, so called pony rods are used (to space out the pump). The sucker rods are connected together with threaded couplings, which are approximately 4 inches in length. The design of material used and the size is determined by the operating well conditions. The stresses acting on the rod are determined from:

- Tubing and pump size
- Characteristics of pumping unit
- Production rate
- Fluid properties
- Pressure and temperature conditions

There are three major types of sucker rods:

- **Steel sucker rods**: Which are the most commonly used type of sucker rods. They are the cheapest. Problems occur with corrosion, when exposed to salt water, H_2S, CO_2 or O_2. The effects of those media can be minimized with the use of properly designed corrosion inhibitors.
- **Fiberglass sucker rods**: Fiberglass is used in corrosive environments and to reduce the weight of the whole rod string. This action results in lower energy consumption and the pump can be set deeper, if required.
  Fiberglass rods tend to brake under compressive forces and are more sensitive to fatigue failure. The strength is affected by high temperatures. One of the major weak points are the end-connectors. They could separate from the rod resulting in a workover operation.

Storage is a large topic in fiberglass rods. They have to be protected from ultraviolet light. Furthermore surface scratches has to be avoided.

- **Continuous sucker rods**: Continuous sucker rods are produced without couplings, except at top and bottom of the rod string. This fact has several benefits on overall operation. The first effect is the reduction of rod weight and the second in the uniform friction over the whole length of tubing string. The rod string is in full contact with the tubing, thus increasing the friction forces, but equally distributing the wear tubing.

2.3.5 Automation of Sucker Rod Operation

Automated control of various surface and subsurface parameters provides a good opportunity to perform early diagnostics, to guarantee a stable production rate and to increase main time between failure. Automation allows:

- Real time dynagraph analysis of pump efficiency, fluid level and loads acting on the whole system.
- Early well problem diagnosis.
- Database for well statistics.
- Remote control of speed and energy consumption.

Sensors should be installed to get data about:

- Pumping speed (SPM, strokes per minute)
- Stuffing box (seal)
- Pressure of tubing / casing
- Production rates
- Polished rod loads
- Static and dynamic fluid level

2.3.6 Advantages and Disadvantages of Sucker Rod Pumps

Advantages

- Sucker rod pump systems are relative simple to operate in field and can be easily analyzed with state of art programs.
- Pumping units can be reused and moved to other wells with a minimum of expenditure.
- Applicable to slim holes and multiple completions.
- SRP achieve highest possible drawdown of the reservoir.
- System is not depending on a specific power source. It can be operated with electric motors or internal combustion engines.
- Corrosion and scale treatment is easy to perform with a chemical injection line or simply injection in to the annulus, when no packer is installed.
- Availability in different sizes and designs.
- Low CAPEX and OPEX, compared to other lifting methods.

Disadvantages

- Crooked or deviated holes give rise to friction and wear problems, if no additional equipment for protection is installed.
- High solids production leads to trouble with:
  - Wear of valves
  - Wear of barrel and plunger
  - Increased energy consumption
- Wells with a high GOR usually lower the volumetric efficiency of the pump; in such cases a gas anchor is recommended.
- Depth limitations due to rod load capacities and fluid conditions.
- Limitations for small casing diameters.

2.3.7 Application in Operational Center Zistersdorf

There are mainly two artificial lifting systems installed in operational center Zistersdorf. The majority of wells are rod pumped and there is a small number of ESP´s. In general there is only one type of pumping unit in use i.e. with class I lever system. These have shown the best performance with respect to production, maintenance and energy consumption.

To handle problems resulting from gas production, some wells are equipped with a gas anchor. This equipment guarantees a successful operation without the risk of gas lock. Good example wells are RAG-045 and RAG-054.

Due to introduction of other technologies to rod pumped wells, as high surface finish coupling, rod guides and poly lined tubing, the operations became even more efficient and MTBF is increased noticeably.

2.4 Corrosion Inhibition System

Corrosion inhibitors are chemicals designed and used to reduce the corrosion rate on metal surfaces. The type of corrosion inhibitor required is highly dependent on the produced medium, type of fines, type of corrosion and conditions surrounding the metal surface. In general inhibitors are used in low concentration of some tenths parts per million (ppm). Corrosion inhibitor is an essential element to increase mean time between failure and to operate mature fields under economic conditions. They provide a relatively inexpensive opportunity to improve operations.

2.4.1 Types of Corrosion

Depending on given conditions and occurred damage, corrosion types can be divided into several major groups: (Byars, 1999)

- **General corrosion**: This type of corrosion is a uniform thinning of metals. Basic mechanism is a chemical or electrochemical reaction, which takes place on the surface of the metal. This type of corrosion is the most commonly spread worldwide.
- **Localized corrosion**: Consists of several corrosion mechanisms (pits, groves and crevices). Pitting is one of the most destructive forms of corrosion, because equipment fails rapidly resulting from reduction of material thickness, due to small holes created on the surface of metal. It is very important to monitor the corrosion rate, especially in maturing fields.
- **Stress corrosion cracking (SCC)**: This type of damage occurs under given tensile stress in a corrosive medium. During operation small cracks are created and spread across the surface and into the body of metal. This can also happen during operation under maximum allowable stress. For stress corrosion cracking some critical conditions which have to be screened and monitored. As presented in Table 2.

Material	Environment	Mechanical Stress
Type	Composition	External tensile stress
Composition	Temperature	Internal stress
Grain structure	Electrochemical condition	Changes in stress

Table 2: Requirements for SCC. (Oberndorfer M., 2011, page 90)

- **Intergranular corrosion**: In this case the metals grain boundaries are attacked by corrosion. It is a result of metallurgical structure of the metal, which causes the grain boundaries to be more prone to attacks. The intergranular corrosion can be reduced by proper heat treatment and a proper control of steel chemistry during the production of the steel. This type of corrosion is mainly seen in austenitic stainless steels.
- **Cavitation**: The main reason of cavitation is rapid change in pressure conditions. It is the formation and collapse of vapour bubbles in fluids, which results in cavitation. These bubbles are created when the pressure in the fluid is reduced to vapour pressure and afterword increased again. This occurs mostly in areas of propellers, pump impellers and surfaces where rotational speed occurs.

- **Bimetallic corrosion**: This type is depending on the reactivity and potential difference between metals, when connected to each other. The reactive metal with low resistance to corrosion becomes the anode and the one with high resistance to corrosion becomes the cathode. In Figure 17 the standard EMF series (Electromotive Force series) of metals is shown.

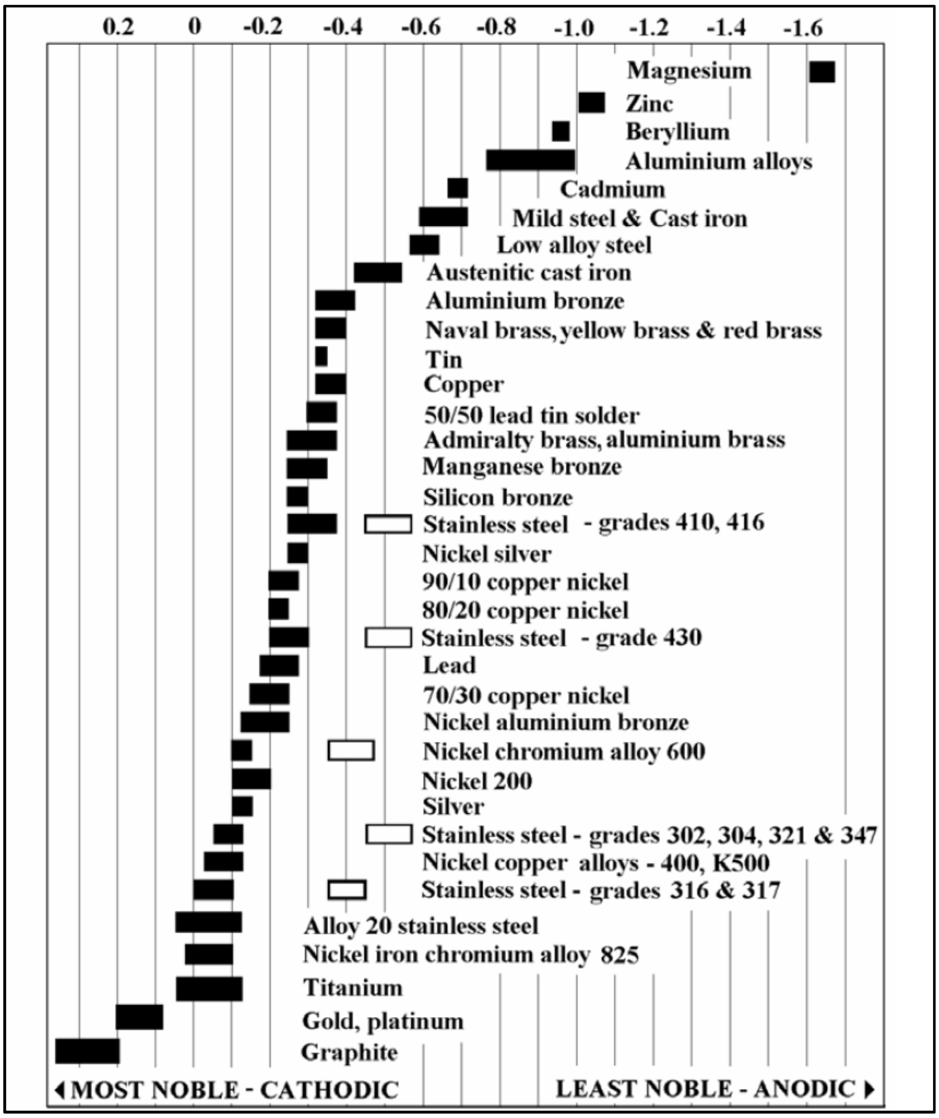

Figure 17: Electromotive force series of metals. (Cossosionist, 2012)

To guarantee a safe and economic operation without failure of equipment due to bimetallic corrosion, some points should be considered:

- Select metals which are close together in EMF series.
- When dissimilar metals are selected they should be isolated from each other
- Corrosion inhibitor is recommended.
- Sacrificial anodes should be placed and designed in areas, where access and replacement is easy.

- **Hydrogen induced damage**: Hydrogen corrosion is caused by the presence of hydrogen or interaction of the material with hydrogen. This type of damage can be classified into 4 major groups: (Oberndorfer M., 2011, page 90)
    - **Hydrocarbon blistering**: Penetration of hydrocarbon into the metal, resulting in local deformation and sometimes in total destruction.
    - **Hydrogen embrittlement**: Penetration of hydrogen into metal, resulting in losses in ductility and tensile strength.
    - **Decarbonization**: Produced by hydrocarbons at high temperatures, which lowers tensile strength.
    - **Hydrogen attack**: Interaction with alloys in high temperature environments.

Figure 18: Example of hydrogen blistering. (Daniels, 2012)

- **Erosion**: Erosion of metal is caused by high velocity and turbulent flow, where small particles and water droplets in the fluid cause erosion and reduce the thickness of the metallic parts. In most cases damage is restricted to certain areas. To prevent erosion the following points should be taken into account:
    - Selection of metals with higher resistance to erosion.
    - In the design phase the velocity and composition of the future fluids should be considered (example: larger diameter for lower velocity).
    - Application of corrosion inhibitor.
    - Reduction of particles and fines in fluid (application of ceramic sand screen).

Figure 19: Example of erosion. (Pair O Docs, 2012)

2.4.2 Selection of Corrosion Inhibitor

The selection of the correct corrosion inhibitor is particularly important and has a very significant impact on the economic success of the overall operation. Before starting a selection procedure for the inhibitor, a detailed investigation has to be carried out to get information about:

- Corrosiveness of fluids and gases.
- Conditions which would increase the rate of corrosion like pressure, temperature, flow rates, fines, bacteria, etc.

After detailed investigation potential inhibitor candidates have to be selected. Often recommendations of a supplier or certain inhibitors based on earlier experience from previous applications are taken into the screening procedure. To confirm the selection of the inhibitor the following actions should be taken:

- Verify supplier's information
- Eliminate non-performing products
- Identify best performing products
- Determine physical and chemical properties

Final step is to perform a field test with the successful candidates to get the best performance. In the Figure 20 a work flow chart of the selection process is shown.

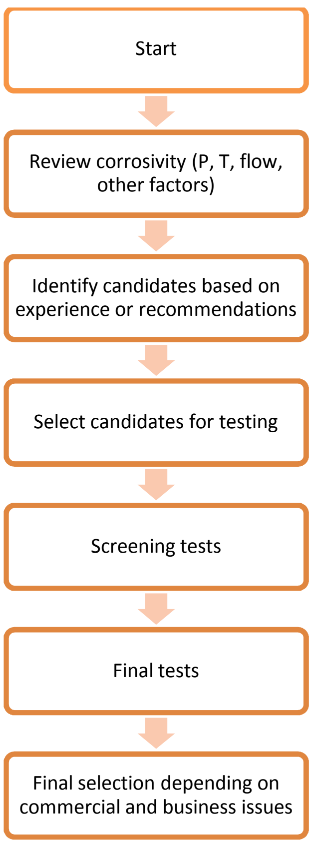

Figure 20: Corrosion inhibitor selection workflow procedure.

The following key aspects should be considered:

- Correct concentration of inhibitor should be used.
- Continuous inhibition is recommended as opposed to batch inhibition.
- Selection of injection method is very important.
- Continuous monitoring of performance to get confirmation.

2.4.3 Inhibitor Types

In the E&P industry corrosion inhibitors are divided into 3 major categories, based on their working principle and function:

- **Barrier layer formers**: This type forms the main category of corrosion inhibitors. They generally spread on the surface of the metal and interfere with corrosion reactions. Barrier layer formers can be further subdivided into:
    - **Adsorbed layer formers**: These adsorb to metal surface and interfere with cathodic and/or anodic reaction occurring at the adsorbed area. The build-up of protection films could occur in several steps.
    - **Oxidizing inhibitors, passivators**: These are useful in pH neutral solutions. Their main function is to shift the electrochemical potential of corroding metals to other areas with easy access, resulting in formation of oxides and hydroxides, which protect the metal surface.
    - **Conversion layer formers**: "The passivating inhibitors rely on the development of an insoluble metal oxide which forms in situ on the metal surface" (Dean, 1981).
- **Neutralizing inhibitors**: The main function is to neutralize or reduce the hydrogen ion concentration in the surroundings of the metal surface.
- **Scavengers**: Besides the hydrogen ion there are other corrosive materials or organic compounds (they could form by breaking down acidic products), which have to be removed to reduce corrosion. Such inhibitors must be designed to the point. One example would be to remove oxygen.

2.4.4 Inhibition Methods

Depending on the application, different methods are available. The methods can be classified into two major groups:

- **Continuous inhibition**: Inhibitor is injected at all times in small concentrations into the system. This could be performed via chemical injection line downhole or through the annular space at the surface of the well.
- **Batch inhibition**: In defined periods, inhibitor is injected into the system. The protection at the beginning is high and continues to deteriorate to a minimum after a certain period of time. Then the next inhibition is required.

2.4.5 Application and Results in Operational Center Zistersdorf

A corrosion inhibition system is installed on almost 70% of the wells at the operational center Zistersdorf. The inhibition is carried out through continues injection into the annulus at the wellhead. This method guaranties protection of internal surface of casing (where there is a liquid column) and both surfaces of tubing.

A few wells are equipped with a packer. At these wells no inhibition is performed, because no circulation of inhibitor could be performed. To carry out an inhibition, some wells are equipped with a straddle, to guarantee a path of the corrosion inhibitor. Corrosion inhibitors have been gradually introduced to the field beginning in.2005. The number of wells on corrosion inhibitors increased gradually after acknowledgement of success in pilot wells.

In order to prove the reduction of the corrosion rates, coupons were installed and controlled on a regularly basis. Figure 21 show the development of the corrosion rates over a period of 88 weeks, where every 8 weeks the corrosion rate of the coupons has been measured. After a period of 56 weeks the overall corrosion rates of the whole field have decreased close to 0 mm. This means that the yearly corrosion rate can be reduced by proper corrosion inhibition to nearly 0 mm. This is an extraordinary good result, considering that the average water cut of the field is 97.1% and the CO_2 concentration of the associated gas is ranging to 10%, which is very aggressive. Some single wells showed the reduction to nearly 0 mm after a period of 4 month from the first inhibition. It has to be mentioned that the ppm concentration was kept at a constant level over the whole period of investigation.

The corrosion inhibition showed a very positive effect on the downhole equipment, the run time and thus the MTBF. The number of workover for repairing failures was significantly reduced and with the saved expenditures an increase of production and reservoir measures could be realized.

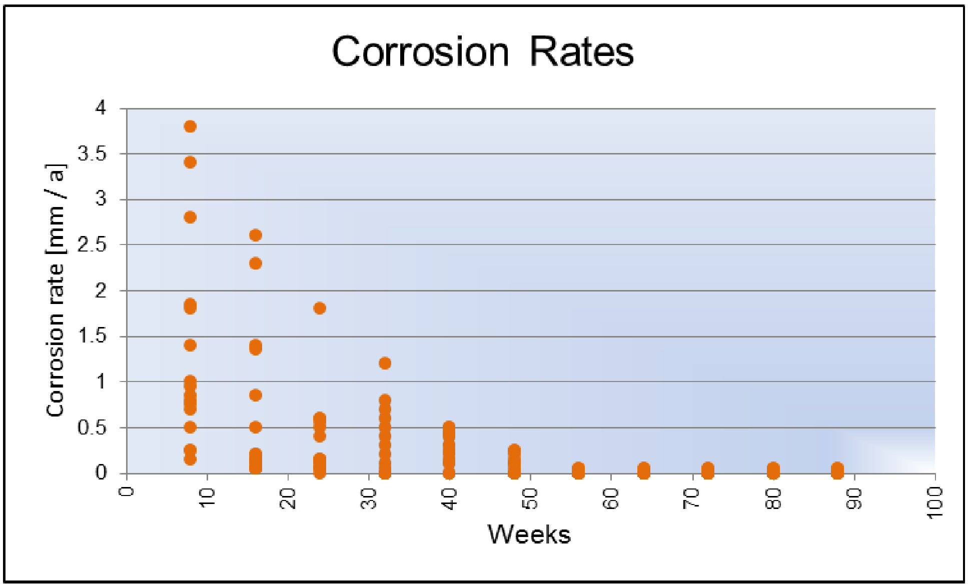

Figure 21: Development of corrosion rates for the whole operational center.

2.5 Ceramic Sand Screens (CSS)

Sand control is critical element to be considered in hydrocarbon production. Conventional sand control methods often show insufficient erosion resistance, which lead to failure of the supporting metal screens. A new development of ceramic sand screens created a milestone in sand control and reduces the related sand problems.

2.5.1 Design of Ceramic Screens

The newly developed ceramic screen is based on a very simple construction and consists of mainly of four parts:

- **Stack of ceramic rings:** These consist of sintered silicon carbide (SSiC™). This material shows hardness 50 times higher than all known steels. Furthermore a high stiffness, low density and high heat stability up to 1800°C is given. One of the major advantages is that SSiC™ discs can be produced for any geometry needed in field operation. Operators can decide which ID, OD, shape and spacing the rings should have to be fit for purpose.
- **Coupling elements**: These parts are used to hold the ceramic rings in place.
- **Metallic shroud**: The main function of this device is to protect ceramic rings during installation and possible future workover operation.
- **Fixing device for installation on tubing**: Is the connection between ceramic sand screen element and the tubing installed downhole.

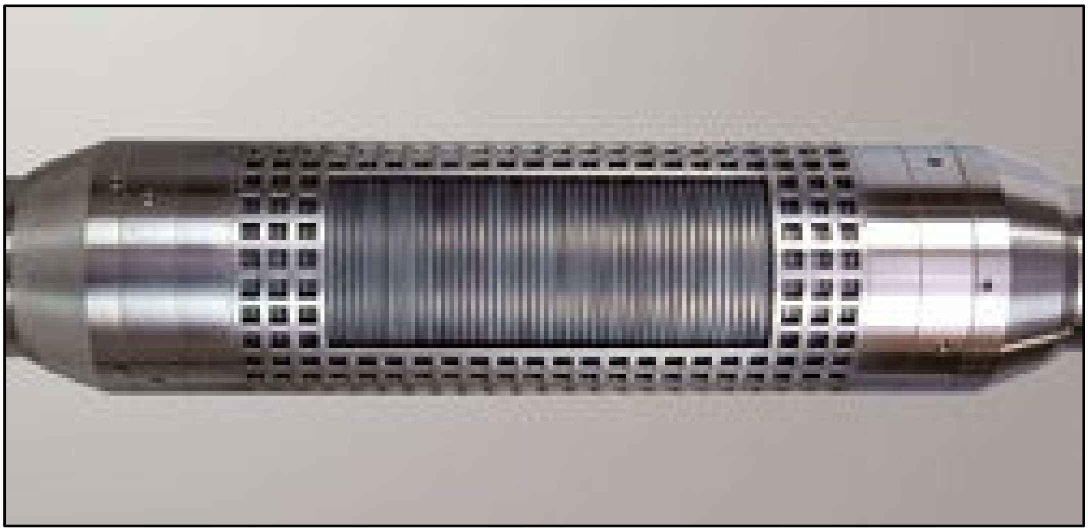

Figure 22: Assembly of a ceramic screen on a conventional 3.5 inch sliding side door. (ESK Advanced Technical Ceramics, 2012)

2.5.2 Advantage of Ceramic Sand Screen Installation

As mentioned before the newly developed equipment has been seen to have a lot of advantages, which cover a wide range of challenges occurring in operation, especially in mature field operation. The most important advantages are listed below:

- Higher hardness and better erosion resistance, compared to conventional sand screen installation, especially when hotspots are created within the gravel pack installation. Hotspots are areas of high fluid velocity, effecting the downhole equipment negatively (failure of equipment within minutes).
- Corrosion resistance even at high temperatures.
- Wide application range due to higher degrees of freedom in design (related to the geometry).
- Installation on any type and size of tubular.
- CAPEX is lower than in gravel pack systems, especially in remote areas, where all the equipment has to be transported to the well site.
- Reduction of pressure drop along the completion, resulting in higher production rates.
- No gravel pack required.
- Protection of whole subsurface and surface equipment from erosion corrosion.
- Less OPEX, due to saving in sand disposal cost and fewer workover operations.

The ceramic sand screen has its strength when the complete life cycle of the well is investigated and the need of long lasting sand control is identified and required.

2.5.3 Application in Operational Center Zistersdorf

Due to the several benefits the application of this system has a wide range of possibilities:

- Installation in fractured reservoirs to keep proppants in place.
- Unconsolidated reservoirs to keep sand in place.
- Installation for protection of equipment like pumps, sliding side door (SSD), etc.

A prototype has been installed in operation centre Zistersdorf. This prototype has shown very good performance. It is a premium product in the segment of sand control and protection. It´s application in mature field is strongly dependent on given conditions and situation.

The above mentioned prototype has been pulled for investigation purposes and a wire wrapped sand filter without gravel pack was installed in its place. This alternative failed after only one day of production. This clearly demonstrates the advantage of the ceramic screen system. The wire wrapped filter was removed and now production is on-going without any filter but at very much reduced production volume to avoid sand mobilization and production.

2.6 MURAG

2.6.1 Principle of Operation

MURAG is a newly developed system, which is superior to all conventional acoustic fluid level measurement systems. The relative accuracy is in the range of +/- 3 meters. Compared to conventional systems it has zero emissions, because no gas is vented into the environment. Furthermore it can be applied permanently in hazardous areas. MURAG gains data through generating several types of signals, which are propagated into annular space of the well. Returning signals are then captured, transmitted and recorded. MURAG consists of two main parts:

- **Measurement device**: This is installed close to the wellhead at an opened casing valve and has a working pressure rating of 350 bars. It has two main functions. First to propagate variety of produced signals into the annular space and second to record returning signals. It is a transmitter and receiver at the same time. All data are transmitted via a cable to an evaluation unit.

Figure 23: Measurement devise of MURAG system. (Sam, Kästenbauer, Burgstaller, & Chevelcha, 2012, Page 8)

- **Evaluation unit**: The main function is to calculate and store data coming from measurement device. Information about fluid level is then transmitted to the Supervisory Control and Data Acquisition System (SCADA).

Figure 24: MURAG system installation. (Sam, Kästenbauer, Burgstaller, & Chevelcha, 2012, Page 8)

2.6.2 Advantages of MURAG System

As mentioned above the MURAG system has many advantages compared to conventional fluid measurement tools:

- Simple installation and maintenance due to easy access on the surface.
- System provides continues measurement, up to one measurement per minute. This provides the opportunity for real time management of production.
- Application for control of: ESP, SRP, PCP, jet pump and plunger lift.
- Reduction of pump failures by avoiding pump off conditions, due to real time measurement of dynamic fluid level.
- Data can be used to optimize production via VSD (Variable Speed Drive) application.
- Fully automated measurement.
- System is not sensitive to high well fluid temperatures.
- Can be used for pressure build-up test analysis (reservoir engineering) during shut in phase of a well.
- No noise, no emissions

In Zistersdorf four MURAG systems have been installed and show good performance during operation.

2.7 Rod Rotator

2.7.1 Principle of Operation

A rod rotator is a device commonly used in sucker rod operations. The main function of a conventional rod rotator is to mechanically rotate (index) the rod string on each cycle of operation. This rotation is usually performed with a certain predefined angle.

The rod rotator is installed on the top of the rod string, shortly above the stuffing box. A conventional system is activated by a fix installed cable, which is connected to a walking beam of the pumping unit. The theory is that this action should help to minimize wear of tubing string, rod string and rod couplings. Furthermore build-up of paraffin and asphaltene is reduced in combination with adequate rod guides.

2.7.2 ECRR (Electronic Controlled Rod Rotator)

As can be seen in Figure 25 with increasing number of rod rotations the number of tubing failures also increases. The Electronic Controlled Rod Rotator (ECRR) presents an improvement over conventional rod rotating systems. Conventional rod rotator systems perform one complete rotation of the rod string within 20 strokes, resulting in approximately 300.000 rotations per year. The ECRR reduces the number of revolutions to around 700 in one year. This system indexes the rod string on every 10th stroke just of few degrees giving rise to around 2 complete revolutions per day. The indexing (minimum rotation stepping) is performed by using of a stepping electric motor and a gearbox.

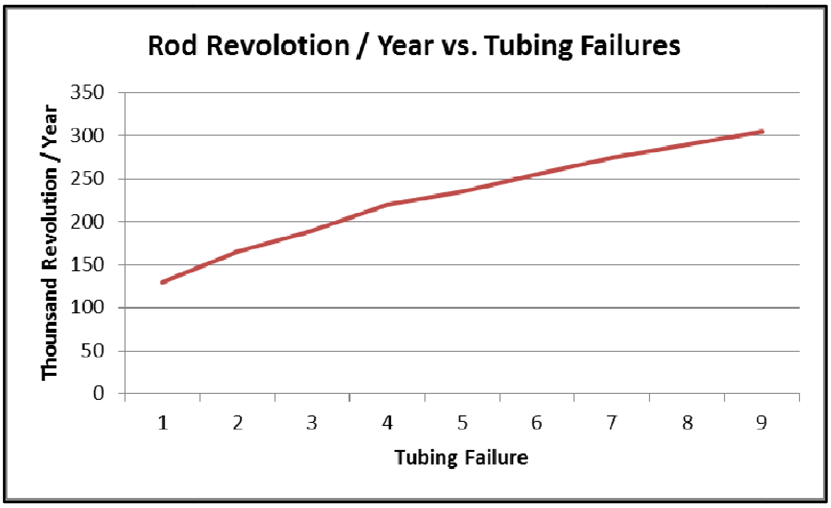

Figure 25: Tubing failure versus number of rod revolutions per year.

Another considerable difference compared to conventional systems is that the rotation is performed only during the up stroke, while the least side load from rod string is applied to the tubing. In general the loads are measured by a load sensor at polished rod string.

Figure 26: ECRR system installation.

Figure 27: ECRR system installation.

2.7.3 Advantages of Rod Rotator

Conventional

- Reduction of wear between tubing and rod string.
- Reduction of coupling wear.
- Relative small CAPEX.
- Prevention of paraffin deposit in combination with rod guides.

Additionally **ECRR**

- Rotation during up stroke.
- Adjustable angle and rotation speed.
- Minimum side wall forces thus considerable reduction in wear on tubing and rod string.

2.7.4 Application in Operational Center Zistersdorf

The standard rod rotator is installed at most pumping units in both fields. The conventional rod rotator is connected via cable to the walking beam. The rotation is performed during down stroke operation of the surface pump, when the cable gets in tension.

GA-010, GA-086 and GA-091 have the newly developed Electronic Controlled Rod Rotator (ECRR) installation. The modified equipment has shown very good performance and helps successfully to increase MTBF as a part of the whole IOR package.

2.8 Rod Guides

2.8.1 Principal of Operation

Rod guides are installed directly on the rod string; this can be done either in the factory or on site. There are several different systems available. All have one common function, which is the reduction of tubing and rod string wear. Additionally rod guides centralize the rod string in the tubing, which has several benefits:

- Reduction of friction between tubing and rod string, resulting in lower energy consumption.
- Prevention of paraffin precipitation on tubing. Especially in combination with rod rotator application.
- Reduction of buckling during down stroke.

When installing rod guides material selection is critical. Materials should be designed for the given well conditions. The composition is one of the main factors leading to success of operation. Modified nylon showed good operating performance in combination steel (J55) tubing. In poly lined tubing application, no rod guides are used.

A critical condition occurs with production of sand. During operation fines can get embedded in the surface of the rod guide, thus acting as emery on the surface of the metal tubing. The installation of a sand filter (ceramic sand screen) is then recommended. When producing sand the use of rod wheeled rod guides is not advisable. The bearings can get stuffed with fines sticking the wheels, which then cause massive tubing wear and additional energy consumption.

2.8.2 Application in Operational Center Zistersdorf

Rod guides are installed on all rod strings run in unlined tubing in Zistersdorf. These are considered to be essential equipment to guarantee success of the operation in combination with other products and technologies described in chapter 2. The only exception is where poly lined tubing is used, where it has been clearly demonstrated in testing that no rod guides should be used.

2.9 Spray Metal Rod Coupling

2.9.1 Principal of Operation

The principal thinking behind high surface finish spray metal rod coupling is to reduce the surface roughness of the material. Looking on Figure 28 (X-axis represents surface roughness, Y-axis represents a certain length of coupling) where the surface finish measurements of standard spray metal coupling and high surface finish spray metal coupling are shown. When comparing both sides to each other, a clear difference in surface roughness could be recognized. On the right side amplitude is not peaking to such high values as on the lift side. The surface roughness for high surface finish (HSF) spray metal coupling is at least 2.5 times lower than standard couplings.

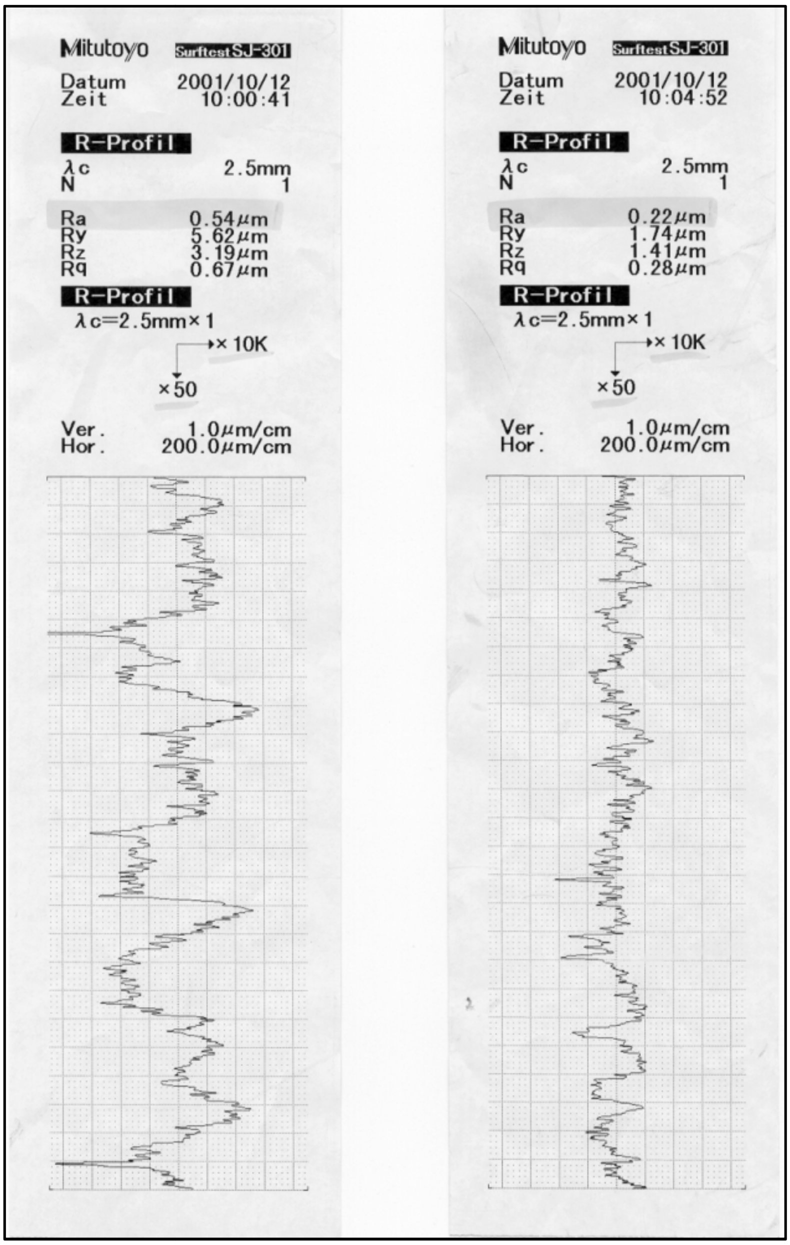

Figure 28: Surface finish measurements.

Analysis has shown that 75% of tubing failures result from wear between couplings and tubing. A relationship between tubing weight loss in % and surface roughness of couplings is presented in Figure 29. The reduced surface roughness of the spray metal couplings plays a major role in increasing run life of tubing. Thus couplings are one of the key components for a successful performance and long operation life.

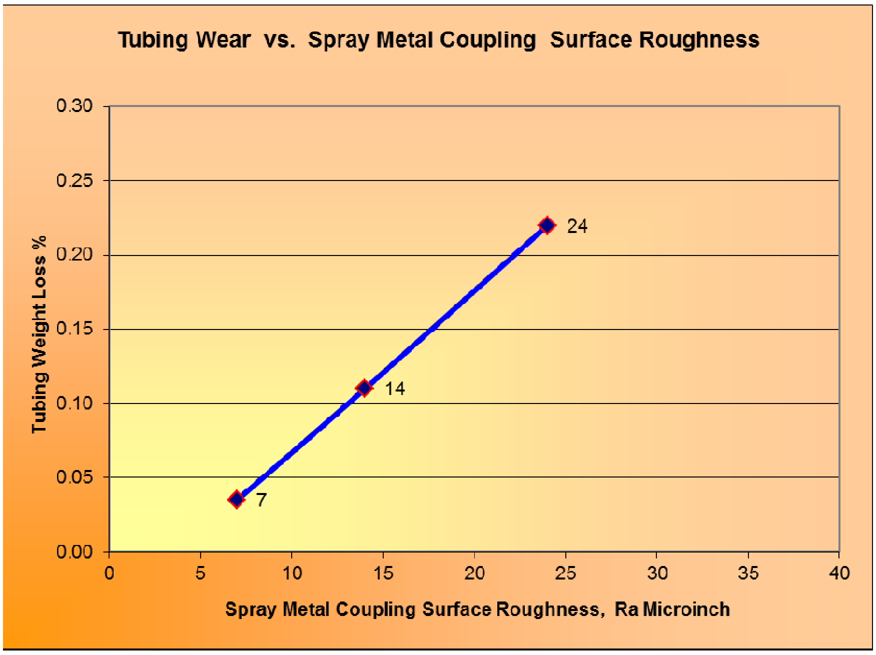

Figure 29: Tubing wear versus surface roughness.

The Spray Metal couplings are designed and manufactured to withstand harsh well conditions, while showing excellent performance of reduced wear and reduced energy consumption. Hardness of the material is in the range of 60 Rc (Rockwell C), typically for nickel chrome based coating. Using special processing the high quality finish surface roughness is significantly reduced.

An interesting observation is the improvement in surface roughness turns the surface into an oil wet surface, which means that with a high surface finish an additional artificially created lubrication between coupling and tubing is achieved.

2.9.2 Application in Operational Center Zistersdorf

These HSF spray metal couplings are installed in every sucker rod application. They have shown very good performance reducing wear on tubing and have had a large influence on the increase of MTBF. The advantage of HSF spray metal rod couplings has to be specially pointed out in combination with poly lined tubing application, where friction and wear are minimal and the energy consumption is reduced in the range of 15%.

2.10 Poly Lined Tubing

2.10.1 General

Tubing and casing are components which have to guarantee a stable oil and gas production and safety of operation. The correct selection of material, installation and maintenance is very important to ensure a successful operation. In mature fields the challenge is maintenance of casing and tubing under economic aspects. The casing is a given fact where normally no changes can be achieved. The main point is the reduction of casing corrosion and wear to increase the life time. The same type of challenge is given for tubing with the main difference that it can be replaced relatively easily.

Nearly all ALS are operated with a tubing in the well, so it is very important to select the right material. Especially in a mature field installation (or partial installation) of poly lined tubing can be a great opportunity to improve the life time of the system.

2.10.2 Characteristics and Benefits of Polyethylene Lined Tubing

Relined tubing is a pipe in pipe system where normal steel tubing is protected by a second “inner tubing” out of high density polyethylene. The liner being a plastic pipe is installed on the inside of metal tubing. Memory effect of PE is used to achieve a tight fit between liner and tubing. This type of tubing application is ideal to manage corrosion problems, because plastic tubing shows very good resistance against corrosion, however reducing of internal diameter (ID) is the result and has to be taken into account for future installations.

A further benefit is that the application of the polyethylene liner reduces wear between tubing and coupling; especially in combination with spray metal rod couplings (see chapter 2.9). Friction (improved surface roughness) is also reduced, which results in lower energy consumption. Analysis showed that energy consumption is reduced up to 15%. A further advantage of the system is the high heat insulation effect resulting in more heat transported to surface and reduced wax appearance in subsurface installations. Temperature difference compared to conventional tubing can be approximately 10°C strongly depending on well depth. Before installing a polyethylene liner the wall thickness of original steel tubing has to be measured. If wall thickness is decreased by more than 50% of original thickness, tubing could fail and it´s use is not advisable. The largest disadvantage of such kind of equipment is the limited depth of installation. This in mainly controlled by the geothermal gradient. Depending on the composition of the PE, poly lined tubing can be used up to a temperature of approximately 90°C.

2.10.3 Application and Results in Operational Center Zistersdorf

To illustrate the benefits of poly lined tubing, the availability of equipped wells was analyzed. In operational center Zistersdorf 4 wells were equipped with poly lined system and showed excellent results due to increase of MTBF and availability of the wells. This had a major impact on production rates of those wells and thus also on their economics. The detailed results of investigations are presented in Table 3.

MTBF without Poly Lined Tubing				
# Workover	**GA-010A [days]**	**GA-060 [days]**	**GA-077 [days]**	**RAG-022 [days]**
1	219	124	82	131
2	81	142	20	244
3	116	13	73	260
4	309	92	100	234
5	65	139	71	144
6	77	94	123	-
7	18	76	24	-
8	77	110	89	-
9	134	311	198	-
10	139	119	197	-
11	145	116	147	-
12	109	326	149	-
13	201	-	99	-
14	-	-	93	-
15	-	-	62	-
Average	**130**	**139**	**102**	**203**

Table 3: Average MTBF before installation of poly lined tubing.

After the installation of poly lined tubing the performance related to availability ranged between 1650 and 2450 days as presented in Figure 30, compared to 102 to 203 days before installation. At the time of writing all investigated wells were still running without any problem, so the MBTF continues to increase. In conclusion the technology provides at least eight times longer availability. The best well shows an increase of over 25 times. This means a saving of 8 to 25 workover operations per well. Not taking into account the additional production per well, which enhances the economics additionally (see chapter 3.5). The analysis of economic value of this technology showed that the additional investment is paid back in 150 days to 250 days for selected examples, strongly depending on length of installed poly lined tubing and depth of installation.

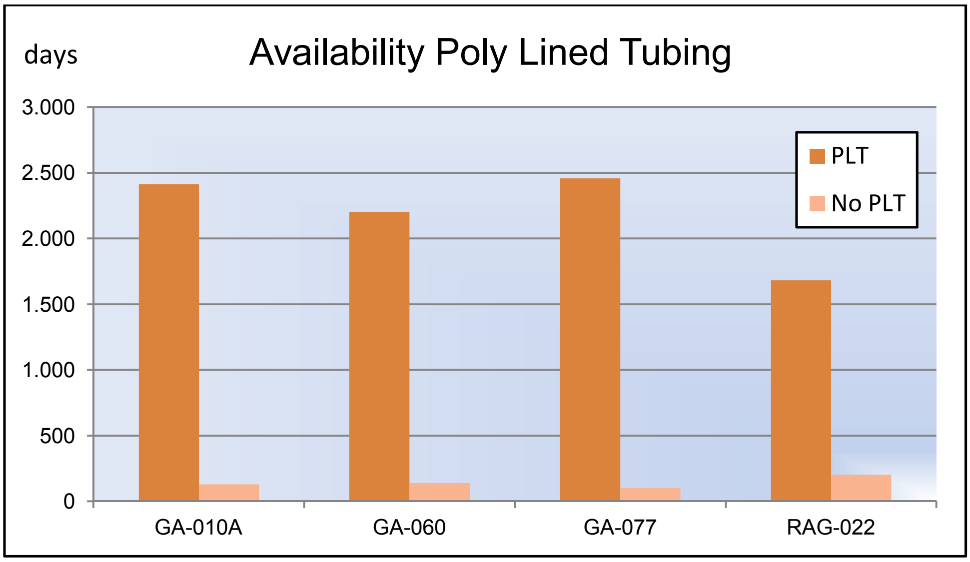

Figure 30: Availability of wells equipped with poly lined tubing versus average availability of wells without poly lined tubing.

3 Economic Analysis of Operational Center Zistersdorf

3.1 General Input and Information

Oil and gas production in Zistersdorf is mainly generated from 2 fields, the Gaiselberg field and the Rag field. Both fields have been producing for about 75 years. Average water cut is in the range of 97.1% (2012). Operating these fields under economic conditions is the main focus of RAG Company. Investment for the development of new technologies has been spent, to ensure success of business in the operation center Zistersdorf.

Operational center Zistersdorf is located in the area north of Vienna, as marked and shown in Figure 31 by the red circle.

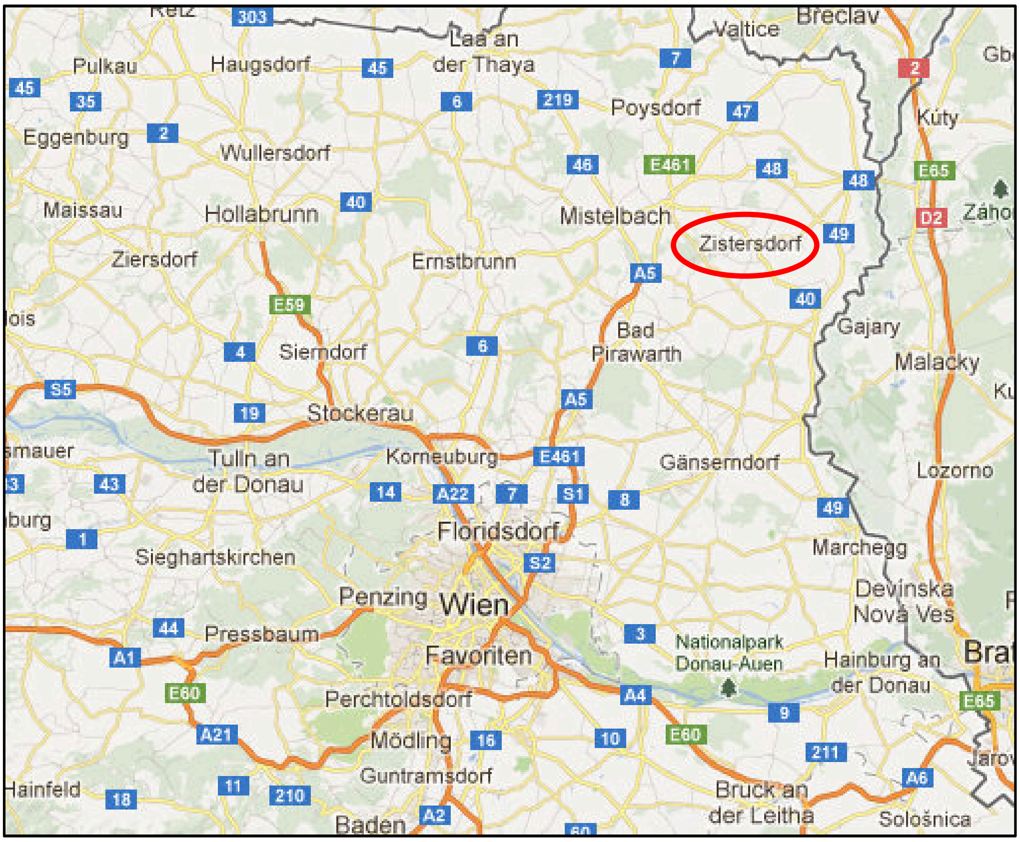

Figure 31: Location of Zistersdorf. (Google Maps, 2012)

In Figure 32 and Figure 33 the well configuration of both fields is presented in detail. The number of active wells 2011 was 33 in Gaiselberg field and 5 in Rag field. Oil producing wells are represented with a green dot, gas producing wells with a red dot and water injection wells with a blue dot.

Configuration of injection wells changed over the years, to optimize the water flooding performance. At the moment the Gaiselberg field water injection wells are located in the south eastern part of the field and in the eastern part of the Rag field. In general wells in both fields have a maximum true vertical depth (TVD) of 900-1000 m.

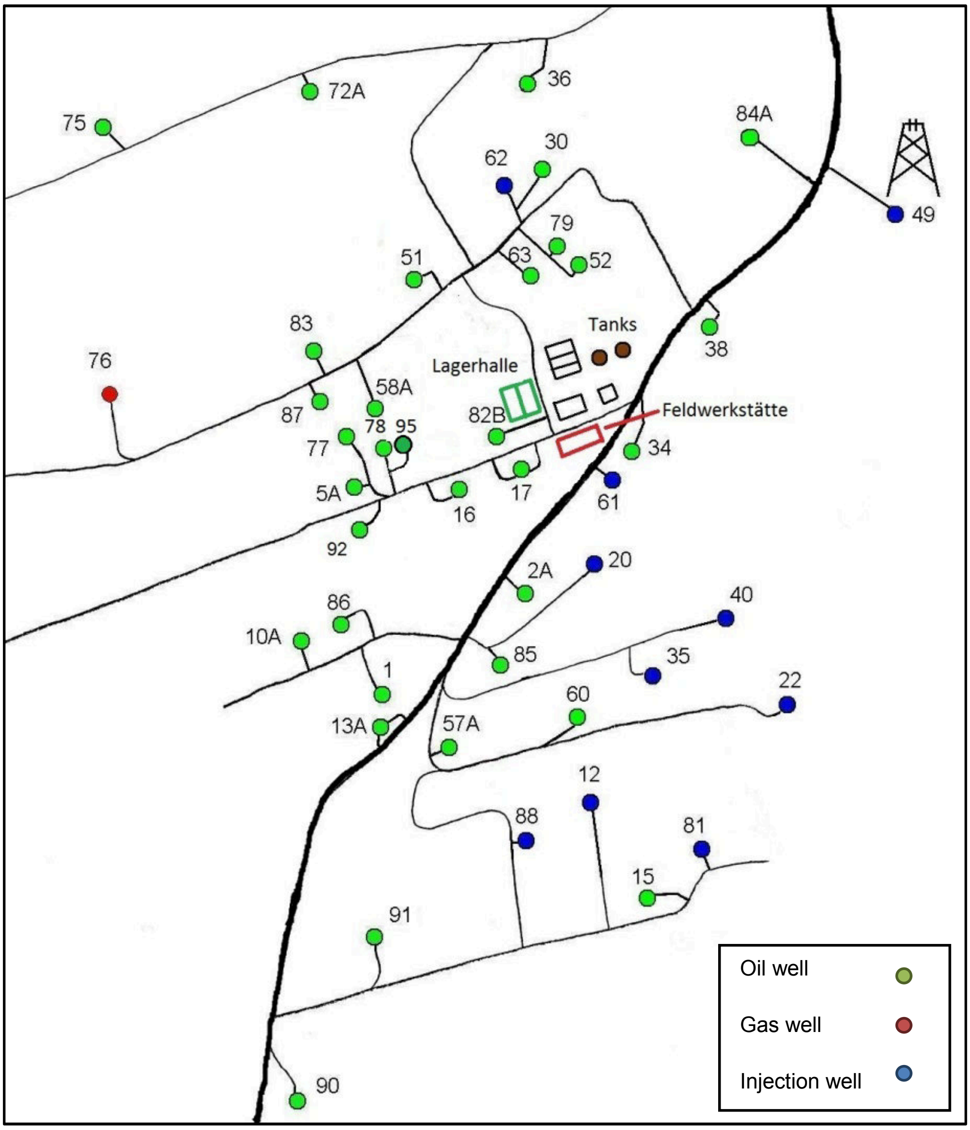

Figure 32: Well configuration of Gaiselberg field.

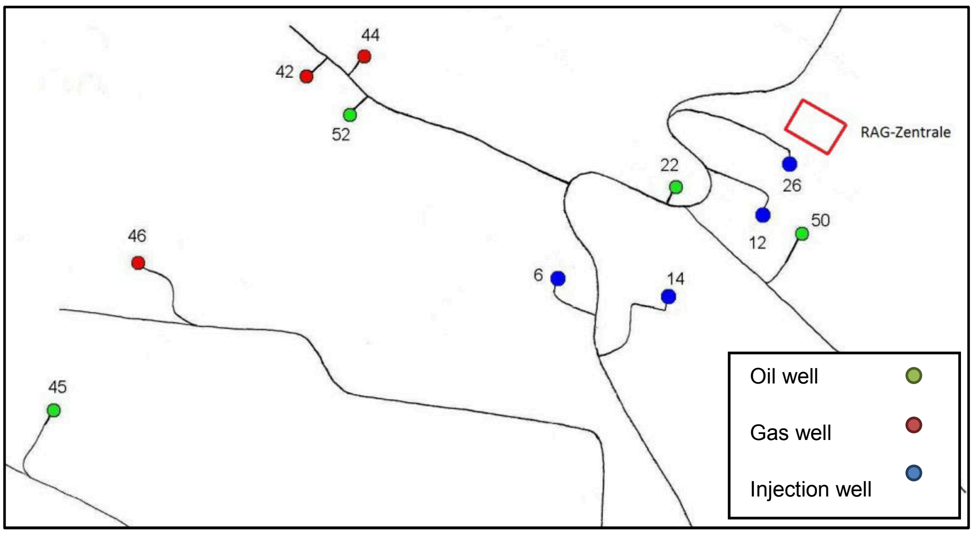

Figure 33: Well configuration of Rag field.

In this chapter the economic value of new technology applications and their implementation will be discussed. Success in operational center Zistersdorf arises from a combination of various improvements:

- Implementation of new technology.
- Improved production of oil and gas, through reduction of reservoir decline.
- Constant level of expenditure, with increased production.
- Quantity of workover reduced which were caused by failures, simultaneously with an increase in availability.
- Sensibilized staff to equipment replacement and workover operations.

To get an impression of size, time and effort needed the number of active wells between 2002 and 2011 are shown in Figure 34. It can be clearly recognized that the number of active wells increased gradually from 2004 onwards. The decrease in number of active wells beginning in 2008 was a result of several well abandonments, coming out of the nature and age of both investigated fields. It has to be mentioned that also wells with small availability are defined as active wells as discussed in detail in chapter 3.5.

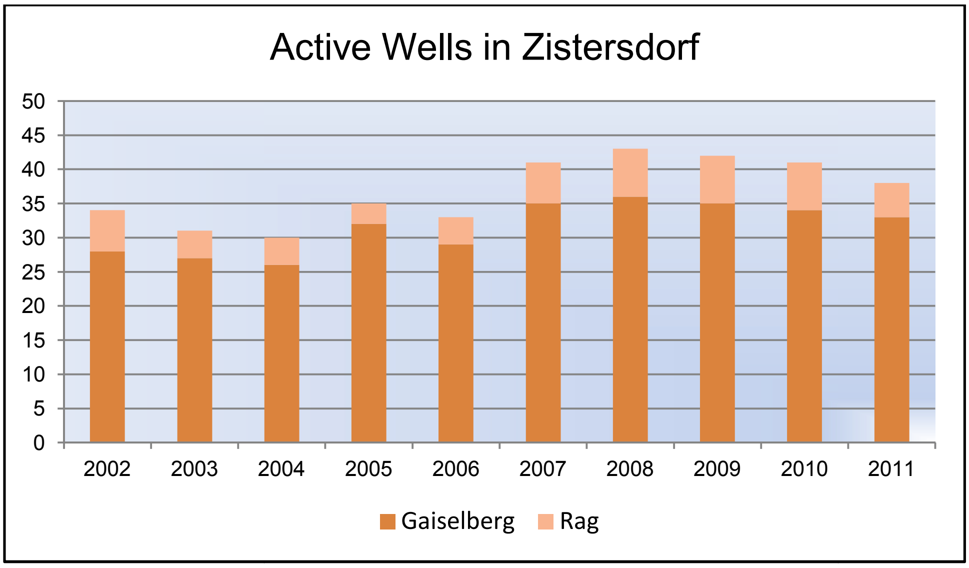

Figure 34: Number of active wells in operational center Zistersdorf between 2002 and 2011.

In Figure 35 the cumulative historical oil production of operation centre Zistersdorf is presented. It can be seen that the peak in oil production was in the year 1942, where 319,000 tonnes were produced. In 2011 oil production was 19,500 tonnes, which is less than 7% of peak value achieved 60 years ago. Analyzing the production to staff ratio for the mentioned years results in:

- 266 tonnes / person for 1942.
- 2150tonnes / person for 2011.

This ratio reflects the effect of the gradual technology development over decades. More oil can be produced with less staff. Compared to other operations worldwide this is an excellent figure.

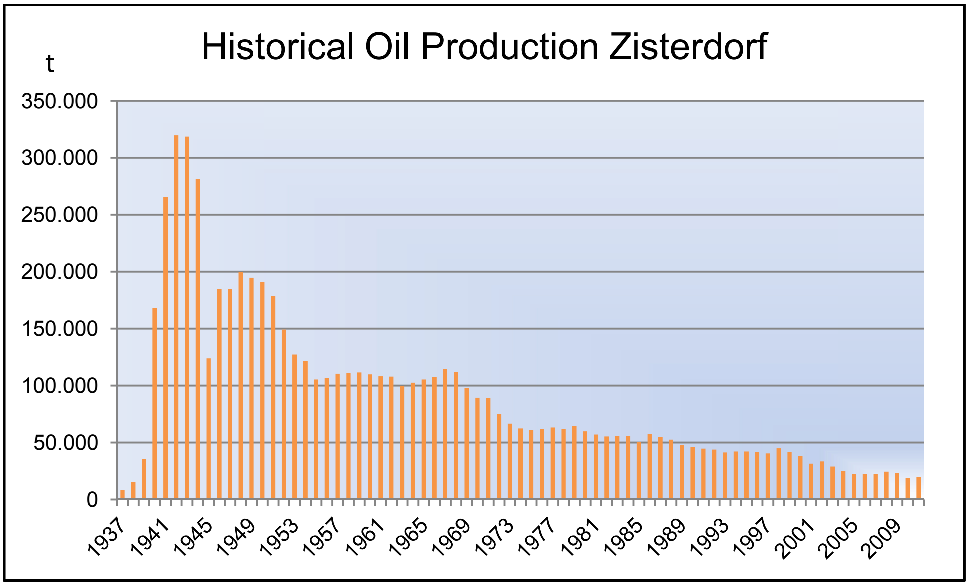

Figure 35: Historical oil production in operational center Zistersdorf.

In Figure 36 the oil production of investigated period between 2006 and 2011 in shown.

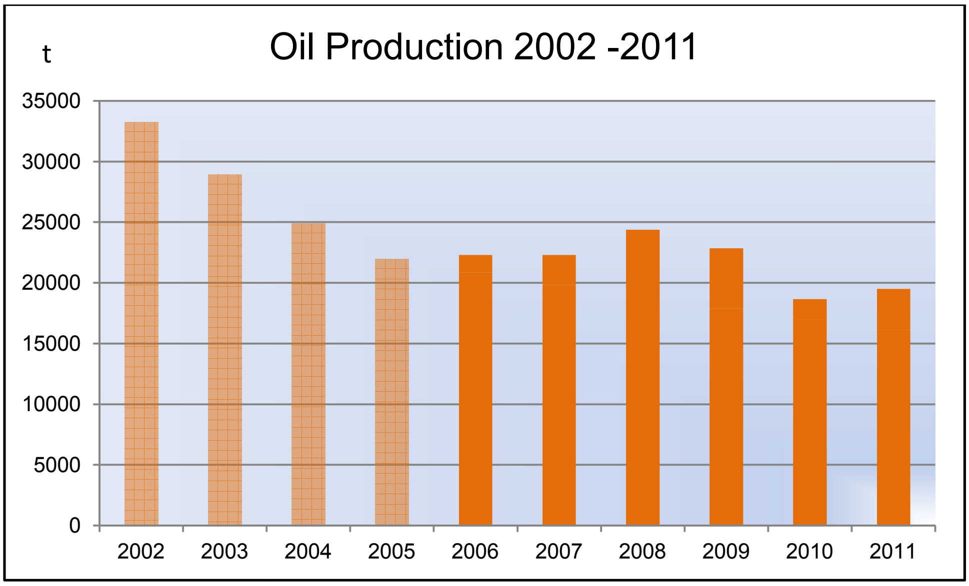

Figure 36: Oil production in operational center Zistersdorf between 2002 and 2011.

The main focus of this thesis is directed to the period between 2006 and 2011, where all data were available in digital form. This period was also detected as the most interesting one, because efforts of technology were starting to become conspicuously and a detailed analysis was possible to obtain. It has to be mentioned that the oil production decline, starting from 1996, showed nearly a linear behavior, which in a very important consideration for further economical analysis in this chapter.

3.2 Expenditure and Revenue Analysis

3.2.1 Expenditure Categories

In Table 4 an overview of the identified expenditures for operational center Zistersdorf is presented. Zistersdorf is defined and analyzed as one single economical unit. All expenditures related to this unit are divided in 12 main categories. Each category includes specific expenditures, which are shown in Appendix A. Furthermore the specific values of each category and subcategory for the period between 2006 and 2011 can be seen. Overhead expenditure outside Zistersdorf is not considered in this analysis.

Category	Category includes expenditures related to
Workover rig	
Staff	Salary, bonus, material, equipment, training, etc…
Mud deposit	Reconstruction, energy, material, etc…
Abandonment	Abandonment cost, material, etc…
Station	Material, energy, chemicals, reconstruction, etc…
Depreciation	Repairs, wells, assets, etc…
Production	Material, energy, transportation, logging, survey, service staff, reconstruction insurance, replacements, etc…
Treatment	Tubing cleaning, rig, survey, rent, energy
Residual water	Material, chemicals, energy, reconstructions, etc…
Water treatment	Material, chemicals, energy, survey, electrical work, etc..
Inactive wells	Chemicals, survey, construction work
Other expenditures	Communication, automobiles and trucks, etc

Table 4: Expenditure categories in operational center Zistersdorf.

The sum of the total expenditures between 2006 and 2011 is shown in Figure 37. It can be noticed that there is a nearly constant increase of annually 2.5% over the analyzed period. The main reason of this increase is the inflation growth, which has a considerable effect on all before mentioned categories.

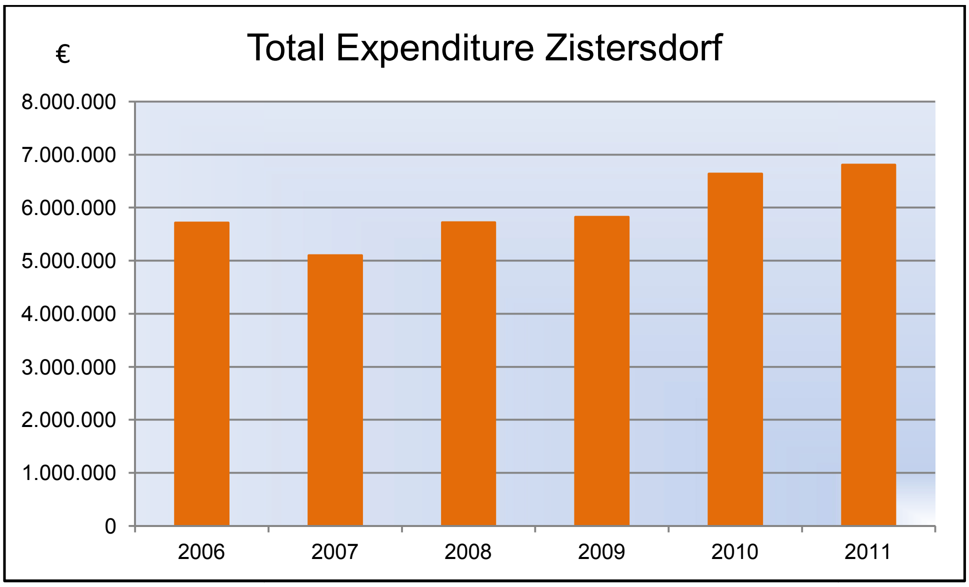

Figure 37: Total expenditure of operational center Zistersdorf between 2006 and 2011.

3.2.2 Workover Rig Expenditure Development

The workover rig expenditure is one of the main cost drivers in operational center Zistersdorf. This category has a relative portion of overall expenditure lying between 13.4% and 18.2%.

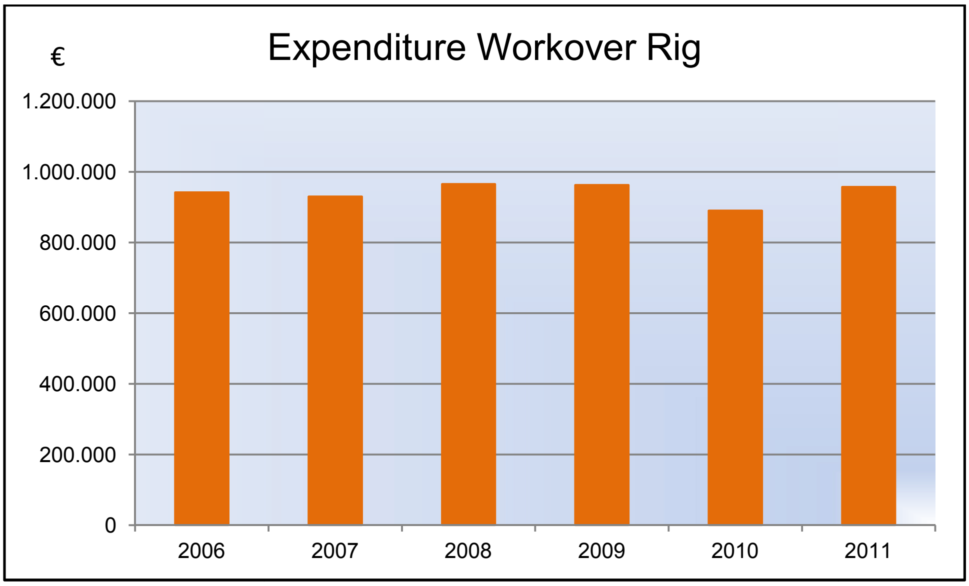

Figure 38: Workover rig expenditure between 2006 and 2011.

In Figure 38 expenditures related to workover rig are presented. It can be seen that the expenditures are ranging between € 890,000 and € 965,000. The sum of workover rig expenditure stay at a nearly constant level, however, the expenditures for workover caused by equipment failures were reduced from 29% in 2006 to 7% in 2011. This results in a reduction by 75%, within 6 years (see Figure 39). This also means more time was available to use the workover rig for production enhancement interventions. Routine workover is defined as an operation, which has no relation to repair of failed equipment and which leads to production level increase or stabilization.

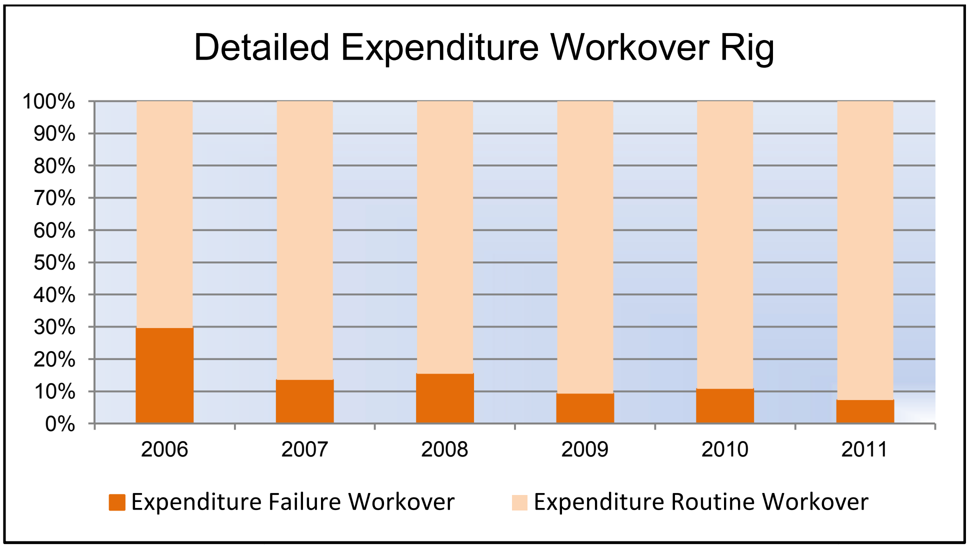

Figure 39: Portion of expenditure categories within workover expenditure.

3.2.3 Production Expenditure Development

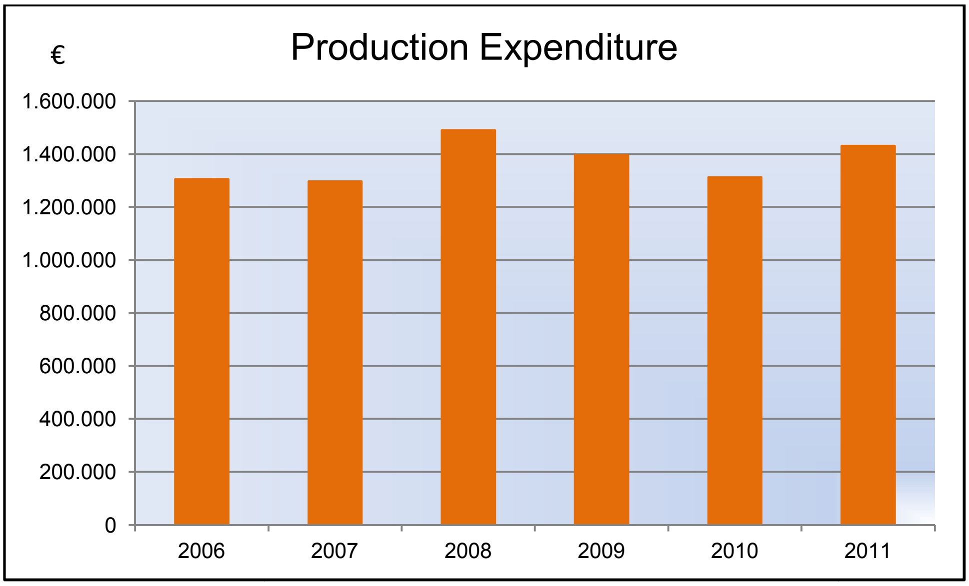

Figure 40: Production expenditure of operational center Zistersdorf between 2006 and 2011.

Production expenditure is related to actions of producing the wells. No failure workover or routine workover are taken into account for this category. The production expenditures are mainly generated out of the operational expenditures (OPEX) needed. It has the largest relative portion of the total expenditures, ranging between 19% and 26% annually, thus between € 1,3 MM and € 1,5 MM as shown in Figure 40. This fluctuation in expense is coming from the changing quantity in active wells.

In Figure 41 the average expenditure per well is shown. This values are varying between € 31,000 and € 37,000 per well. It has to be mentioned that wells with low availability strongly influence this type of analysis, due to changing quantity of active wells (see chapter 3.5).

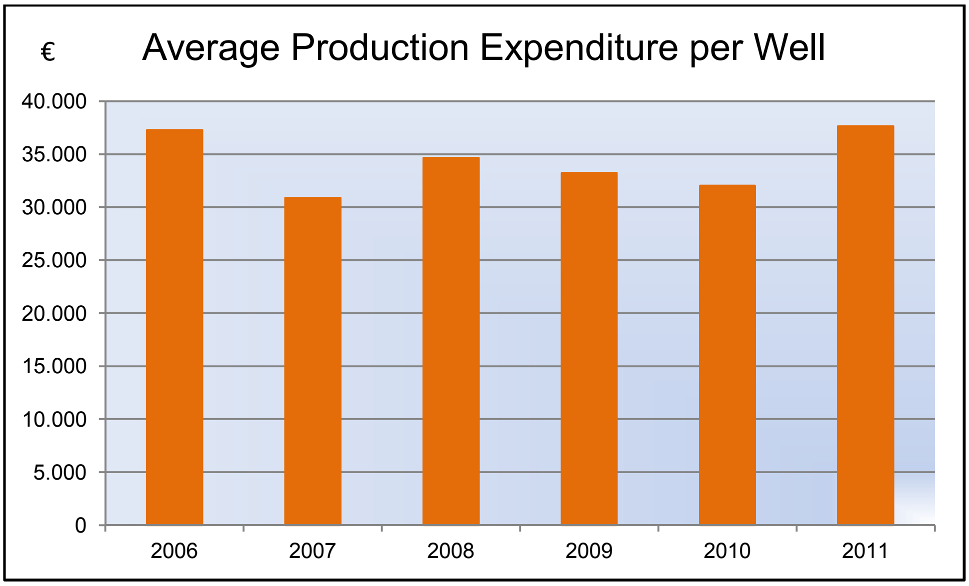

Figure 41: Average production expenditure per well between 2006 and 2011.

3.2.4 Staff Expenditure Development

The category own (RAG) staff expenditures contributes between 13% and 16% of total expenditure in operational center Zistersdorf. It ranges from € 724,000 in 2006 to € 939,000 in 2009, which is an increase by 30% within 6 years. Salary has a relative portion of approximately 60% of the total staff expenditure. 40% is spent on equipment, material, catering, transportation, training courses, office rent, telecommunication, energy consumption of field office. 2009 shows a high value coming from additional expenses for material, training courses, equipment and some extra cost for contractor staff.

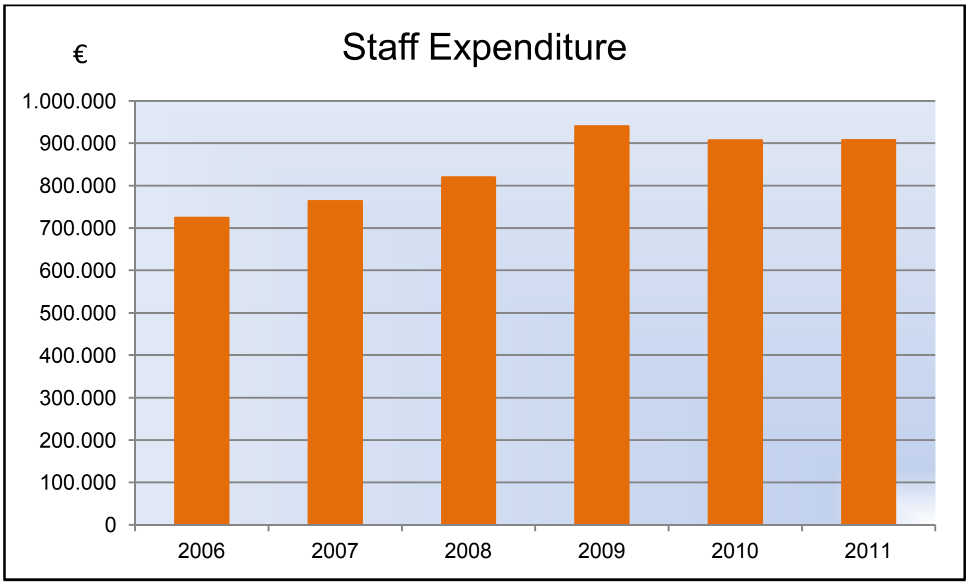

Figure 42: Personal expenditure of operational center Zistersdorf between 2006 and 2011.

The development of this category is somehow depending on the annual negotiations of the oil and gas union in Austria (salary increase, salary is about 60% of this category). In Table 5 the yearly increase of the salaries for the employees in the oil and gas industry is shown. It can be recognized that the increase is nearly proportional to staff expenditure development.

Year	Increase [%]
2006	1.9
2007	4.3
2008	2.7
2009	3.9
2010	3.8
2011	1.5

Table 5: Annual payment increase in Austria between 2006 and 2011.

The increase in the remaining 40% is mainly coming out of inflation increase over the investigated years. In total the annual increase within this category is in the range of 3.5%, representing the highest increase of all investigated categories.

3.2.5 Revenue Development

Revenue in operational center Zistersdorf is generated only from oil and gas production. The revenue achieved by oil production is lying between 91% and 93%; the remaining revenue is generated by the gas production (7% - 9%), which is mainly associated gas. The average price achieved for a tonne of oil varied between € 277 and € 512. For gas it was lying between ct 17 and ct 29 for a standard cubic meter as shown in Table 6.

Year	Oil €/t	Gas €/m³
2006	330.65	0.25
2007	336.81	0.21
2008	426.70	0.28
2009	277.50	0.17
2010	383.07	0.21
2011	511.59	0.29

Table 6: Average oil and gas price earned between 2006 and 2011.

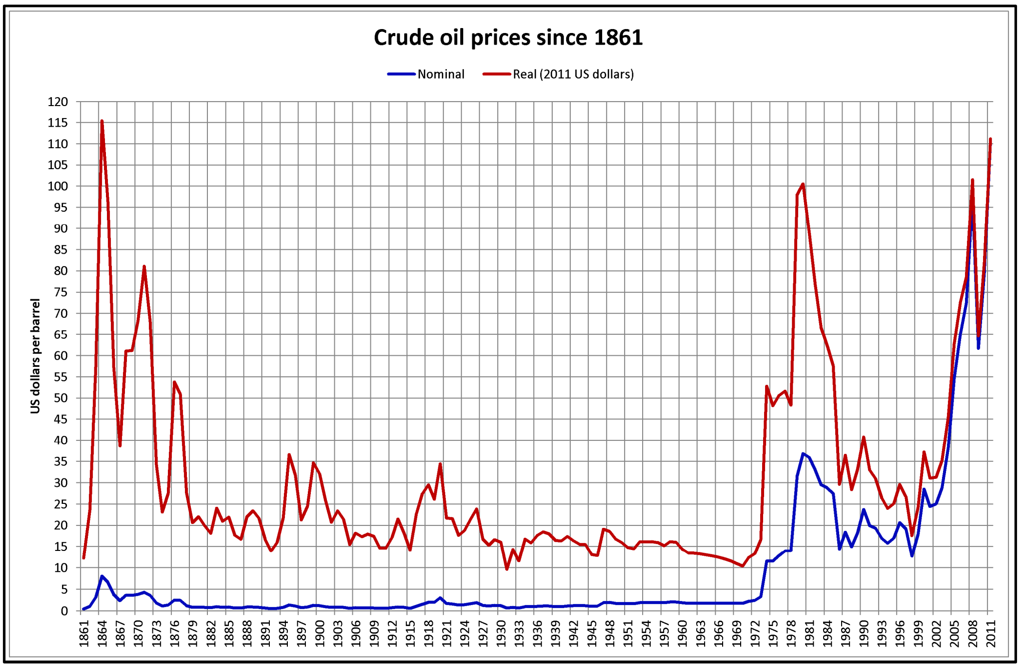

Figure 43: Real and nominal price development crude oil between 1861 and 2011. (Wikipedia, 2012)

In Figure 43 nominal and real oil price development are presented. Analyzing the price development over the last 50 years, a price increase in real term of 3.5% annually is the result. This value is taken as a reference for further calculations and analysis performed in this chapter.

Due to the application of new technology the oil and gas production decline could be stopped in 2005 and turned around to a production increase, generating additional revenues and maintained the economics of the operation.

From 2008 onwards the decline started again due to depletion and age of fields. However it has to be stressed that the average decline rate for both fields has been decreased to 4% compared to 6.8% before technology implementation. Different decline scenarios and the economic value of the introduced technologies will also be discussed in chapter 3.4.

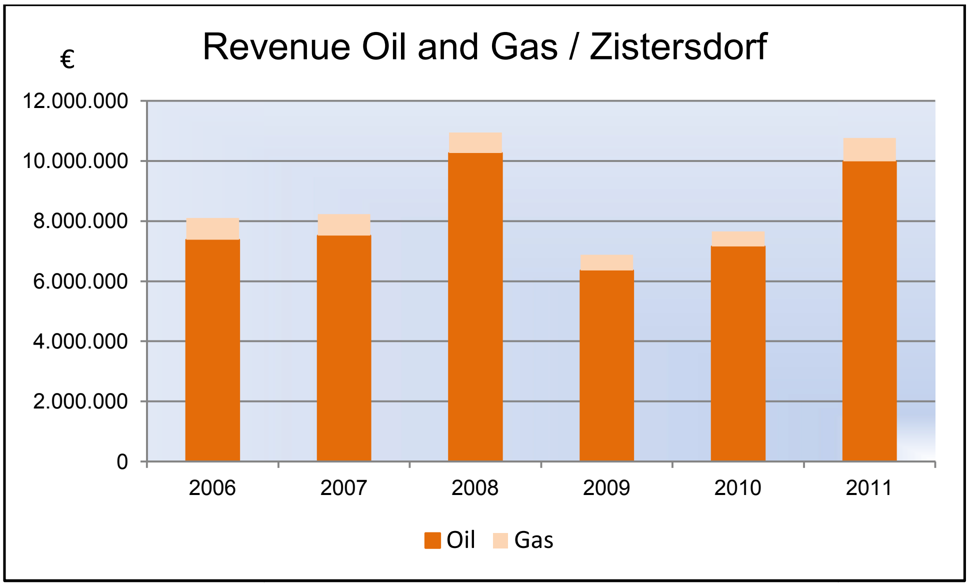

Figure 44: Revenue generated out of oil and gas production in operational center Zistersdorf between 2006 and 2011.

In Figure 44 the revenue development between 2006 and 2011 is shown. Of course the price development of hydrocarbon had a significant influence on the revenues generated. The future price development on the market and the field decline rate determine the point in time at which operational center Zistersdorf becomes uneconomic. By investments into production enhancement measures and application of new technology the economic production could be extended up to another 25 years (see chapter 3.6).

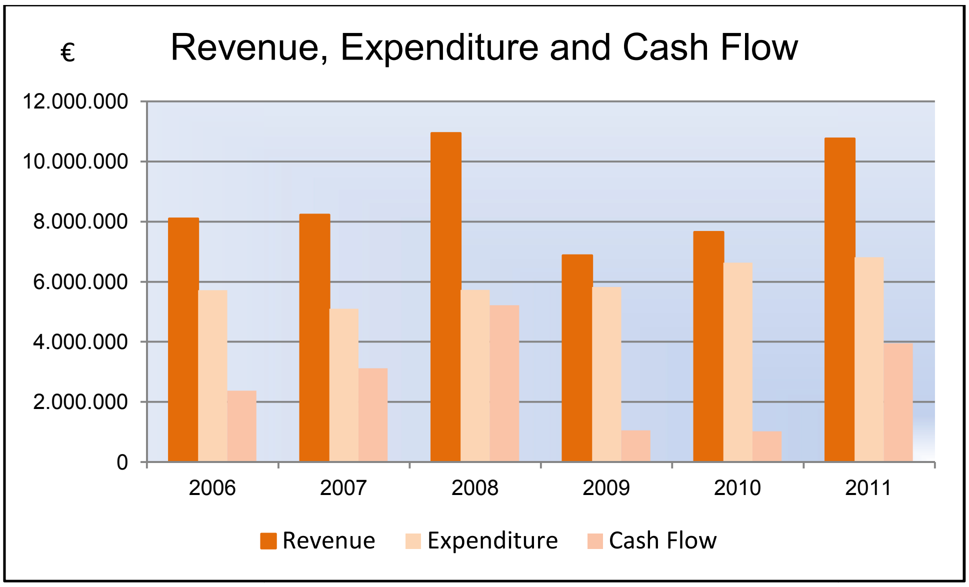

Figure 45: Revenue-, expenditure- and cash flow development between 2006 and 2011.

In Figure 45 the revenues, expenditures and cash flow developments are shown. The calculated rate of return amounts to 15% in 2009 (minimum value) and 91% in 2008 (maximum value). This strong variation in the values is a direct result of oil and gas price development as presented before in Table 6.

3.3 Failure and Routine Workover Analysis

3.3.1 General

Due to new technology application and implementation in operational center Zistersdorf the total number of workover was reduced from 71 in 2006 to 55 in 2011, which is equivalent to a decrease by 23%. The reduction of workover is mainly coming from the reduced number of failures and the increased mean time between failure (MTBF). The so called routine workover operations remained at a constant level of about 50 annually. Due to additional free time of the workover rig, investments into reservoir management measures such as logging, additional perforation or well repairs were possible. In this chapter failure and routine workover will be analyzed and the economic value will be discussed in detail.

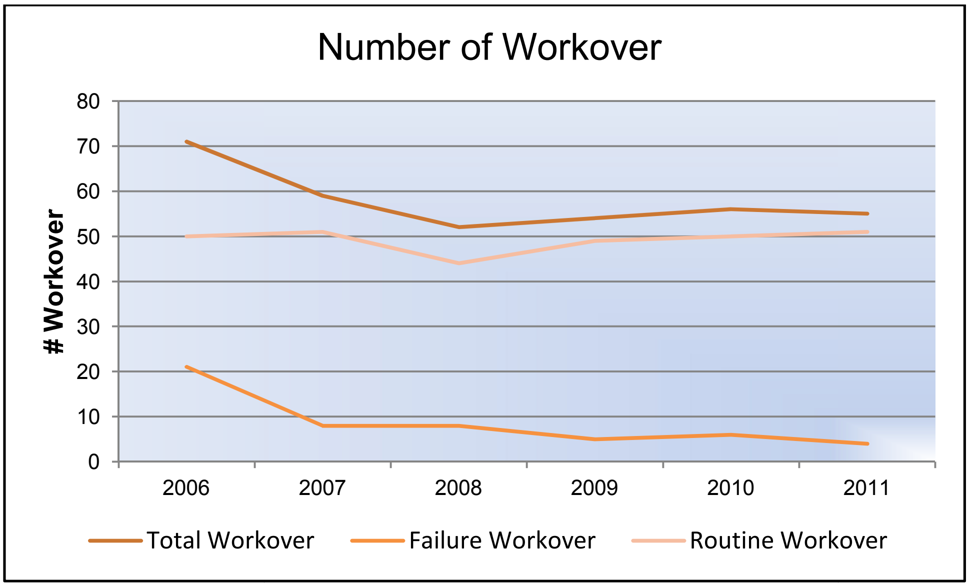

Figure 46: Workover statistics for operational center Zistersdorf between 2006 and 2011.

3.3.2 Failure Workover Analysis

The economic success and the additional production are generated by the reduction of failures due to technology installed and production increase measures. The most important technologies applied have been listed in chapter 2. Since 2005 the described technologies have been gradually applied into both fields of Zistersdorf. Figure 47 shows the development of failures divided into 3 main identified categories:

- Pump failure
- Tubing failure
- Rod failure

Figure 47 shows the number of workover between 1996 and 2012. Despite the application of some new technologies (e.g. fiber tubing) the trend could not by maintained. The number of total failure increased and peaked in 2005, mainly driven by significant cost pressure. From 2005 onwards the number of failures decreased continuously with only three failures in 2012. This is seven times lower compared to 2006 and even 17 times lower than 2005. The numbers of failures for each mentioned category are presented in Table 7.

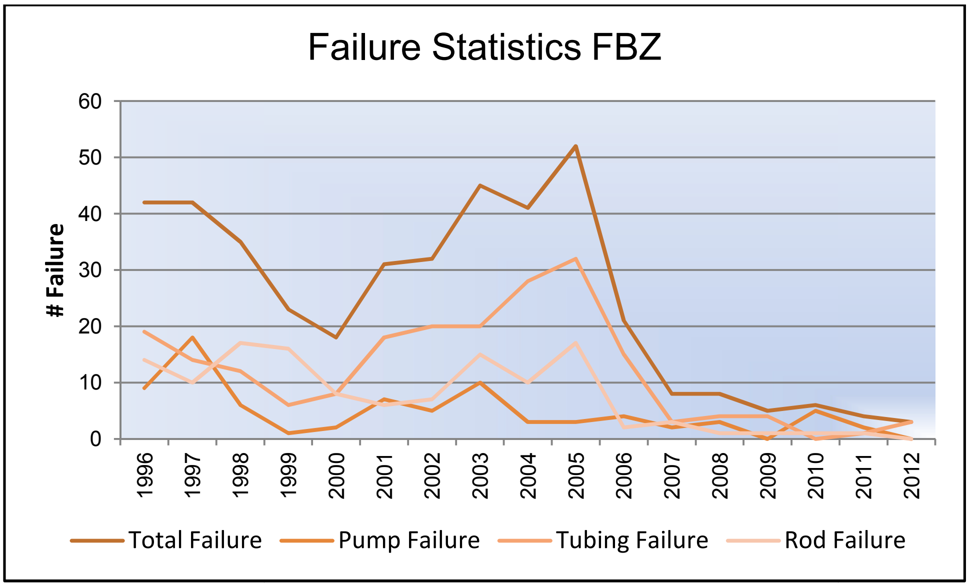

Figure 47: Failure statistics of operational center Zistersdorf between 1996 and 2012.

Year	Rod	Tubing	Pump	Total
1996	14	19	9	42
1997	10	14	18	42
1998	17	12	6	35
1999	16	6	1	23
2000	8	8	2	18
2001	6	18	7	31
2002	7	20	5	32
2003	15	20	10	45
2004	10	28	3	41
2005	17	32	3	52
2006	2	15	4	21
2007	3	3	2	8
2008	1	4	3	8
2009	1	4	0	5
2010	1	0	5	6
2011	1	1	2	4
2012	0	3	0	3

Table 7: Failure statistics of operational center Zistersdorf between 1996 and 2012.

The analysis of every single failure category is discussed in the following pages. To illustrate the value of failure reduction, the average expenditure for a workover operation related to failure of equipment has to be determined. From historical digital data between 2002 and 2005; the average value for such an operation was calculated in the range of € 17,000.

In real terms the average value was transferred to the period between 2006 and 2011, resulting in € 20,000 per workover operation. The expenditure includes material, transportation, repair, installed equipment and contractor staff. The expenditures for RAG staff are not taken into account in such a calculation.

3.3.3 Detailed Failure Workover Analysis

Pump failure

In Figure 48 the annual number of pump failures is shown. It is clearly seen that number of failures has been reduced from 18 in 1997 to 1 in 1999. Due to budget restraints in technology, pump failures peaked between 1999 and 2003 to 10. After 2003 a gradual decline till 2012 is seen, ending with no pump failures.

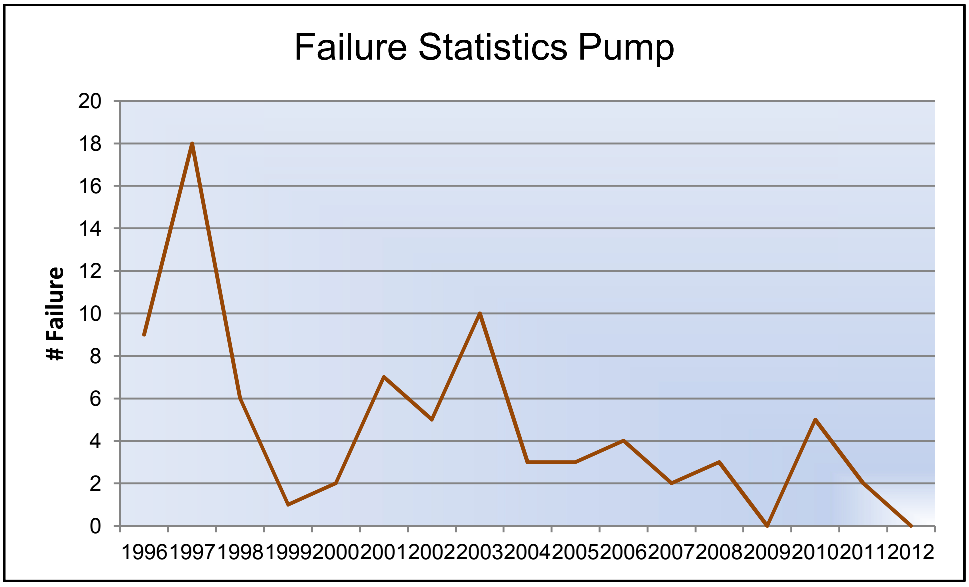

Figure 48: Failure statistics for pump failure between 1996 and 2012.

The bandwidth of expenditure for a workover operation related to pump failure is depending on several parameters:

- Type of pump installed.
- Material selection for subsurface equipment (pump, tubing, sucker rods etc.).
- Depth of pump installation.
- Characteristics of the reservoir fluids.

Taking the average number of pump workover before 2005 as reference, the theoretical cumulative number of workover between 2006 and 2011 would have been 36 pump workover, in the case when no technology would have been introduced into both fields. Taking the records in Table 7 into account where only 16 pump workover were recorded, would result into 20 saved pump workover operations within the investigated period between 2006 and 2011. This is equivalent to a reduction by 55%. The calculated savings amounts to € 400,000, spread over the 6 years of investigation.

Tubing failures

The development of tubing failures is shown in Figure 49. Starting in 1996 the number of tubing workover was 19, which was then reduced to 6 failures in 1999. Again the budget restraints in technology showed a dramatic negative effect on number of failures, consequently also in number of workover operations required to keep operations ongoing. Starting with the application of corrosion inhibitor in 2005 tubing failures were then impressively reduced from 32 in 2005 to 3 in 2012.

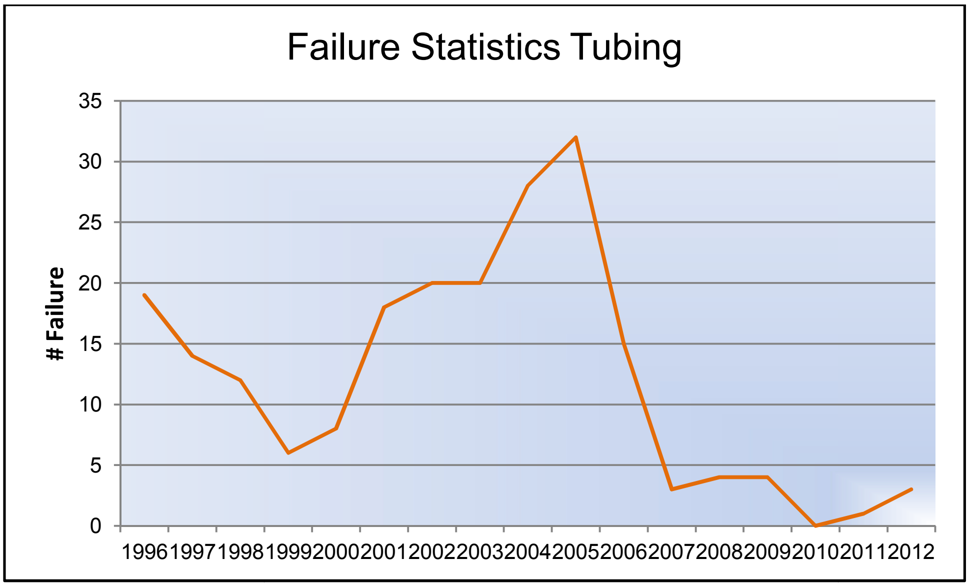

Figure 49: Failure statistics for tubing failure between 1996 and 2012.

Expenses for such kind of operation are depending on:

- Tubing type installed.
- Length of tubing to be replaced.
- Depth of installation.

The cumulative average annual value for tubing failures between 1996 and 2005 was considered to be 18. Taking this number into account for calculations after 2005 would result in theoretical cumulative failures of 108 between 2006 and 2011. Due to the implementation of new technology the real cumulative number for tubing workover was only 27, equivalent to a reduction by 75%. Calculating with an average cost of € 20,000 per workover, savings of € 1.60 MM have been achieved.

Rod failures

The number of workover related to rod failures is shown in Figure 50. It can be seen that values before 2005 are varying between 6 and 19 failures. After introduction of corrosion inhibition to the production system, the number of failures and thus workover was reduced to 0 in 2012. This is an impressive demonstration of benefits of corrosion inhibitor and effects resulting from its implementation (see chapter 2.42.4.5).

Any form of cost containment which would result in inadequate amounts of corrosion inhibitor being used would be false and would immediately show negative effects on the whole production system and on overall economics.

Expenditure for rod workover is depending on:

- Rod length to be replaced.
- Depth of installation.
- Type of couplings used.
- Rod guides application.
- Material selection.

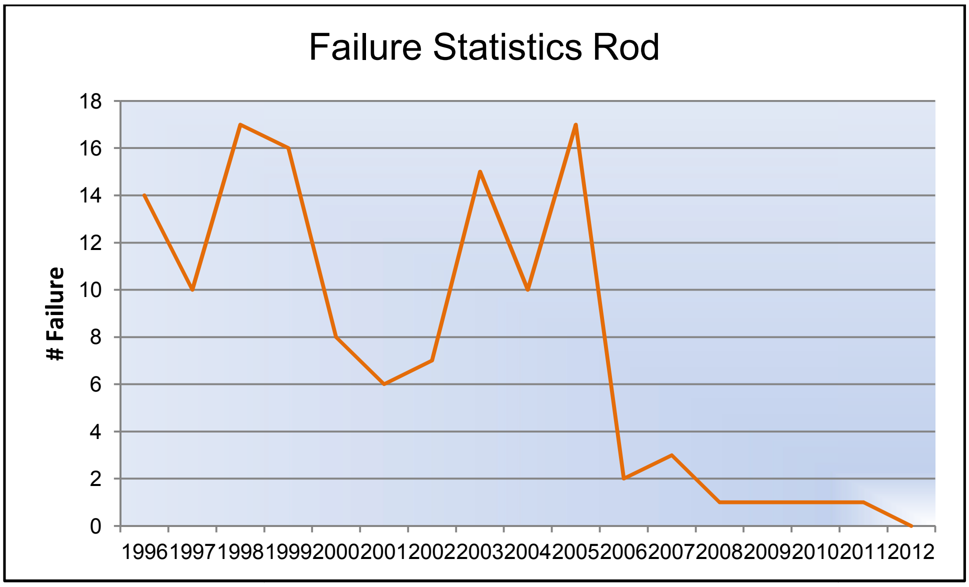

Figure 50: Failure statistics for rod failure between 1996 and 2012.

Considering number of failures recorded before 2005, the average number was calculated to be 12 annually. Theoretically the number of failures between 2006 and 2011 would have been 72, in the case of no technology implementation. Actually only 9 rod failures occurred, which is a theoretical reduction of 88% in 6 years. The average expenditure for rod workover is estimated at € 20,000. This means the achieved savings amount to € 1.25 MM.

If the year 2005 would have been taken as reference even higher saving could have been calculated. So far the calculated values are relative moderate. A model example is shown in the following section.

3.3.4 Worst Case Scenario

Starting from Figure 51 the best case could be defined as follows:

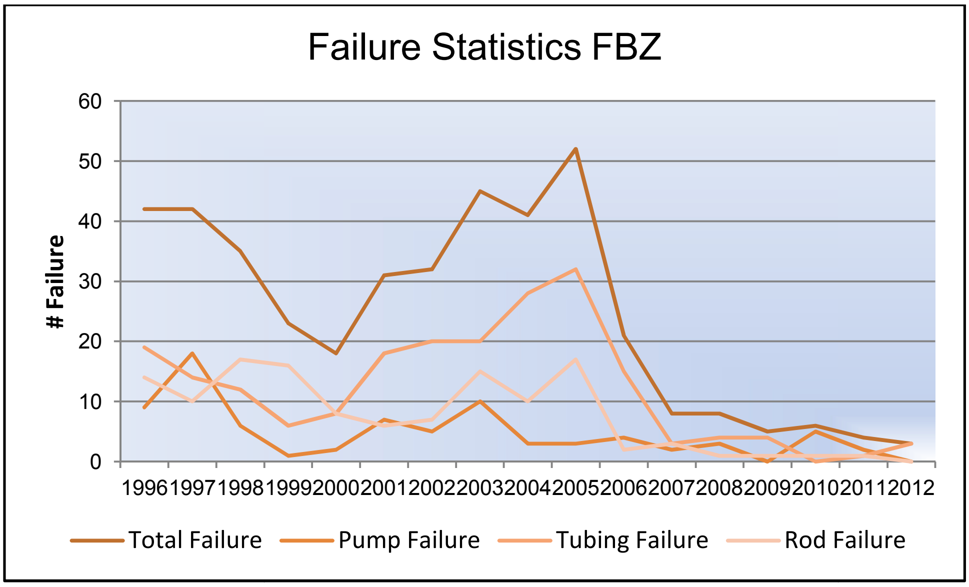

Figure 51: Overall failure statistics of operational center Zistersdorf.

- Workover due to failures remains at a level of 52 annually (value of 2005).
- No new technology implementation, same equipment installed, no improvements performed.
- Same annual budget.

This scenario would result in additional 260 workover operations due to equipment failures. The average expenditure for this type of workover is € 22,000. The additional expenditures would have been € 5.72 MM, only remediation.

In addition no routine workover would have been carried out. Either a second workover rig would have been required with a further increase in expenditures or no additional oil or gas could have been produced and the decline rate could have been not improved. So it is a very important matter to introduce adequate technology into the fields to guarantee the economic success of operation. Another very important point to be mentioned is the gradual introduction of technology into the field. Introducing technology in a large scale in a short period of time could lead to failure of the whole operation. It is impotent to prove performance of desired technology on a small scale and then implement them into a larger scale

3.3.5 Routine Workover Analysis

The annual routine workover operations are nearly constant at a level of 50, as shown in Figure 52. Before 2006 the annual average number of routine workover was 29, transforming this value to the period between 2006 and 2011 would result in cumulative 174 routine workover. Actually 295 routine workover where performed in that period. The average expenditure for such an operation was calculated with € 26.300. The additional investment of € 3.18 MM could be set free from the saved workover due to failure of equipment. The money was invested in better and adequate equipment, inflow improvements, logging jobs, perforations, recompletion and stimulation. All these measures lead to a reduction of the decline rate from 6.8% to 4%, which is better than industry standard.

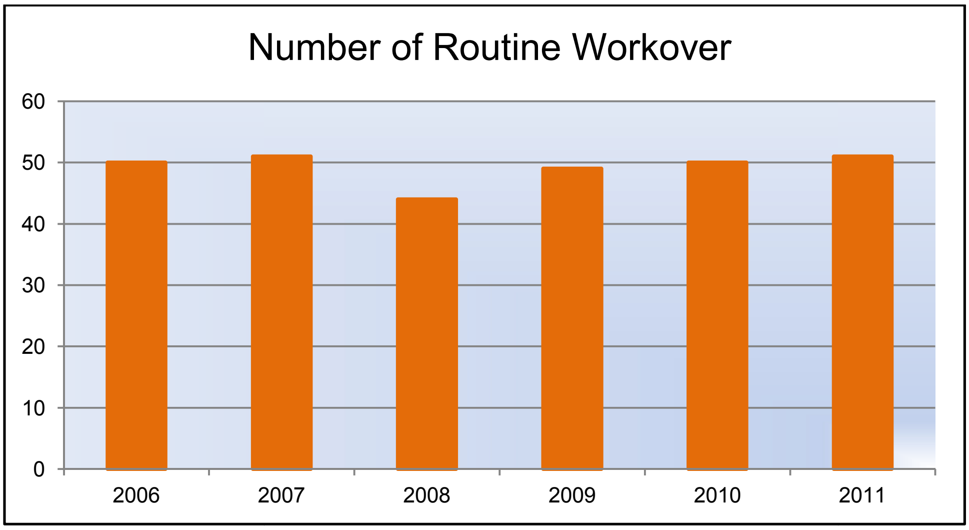

Figure 52: Development of routine workover operations.

In Figure 53 the development of different routine activities (non workover) between 2006 and 2011 are shown. It was often the case that more than one of these activities were carried out during a single workover operation.

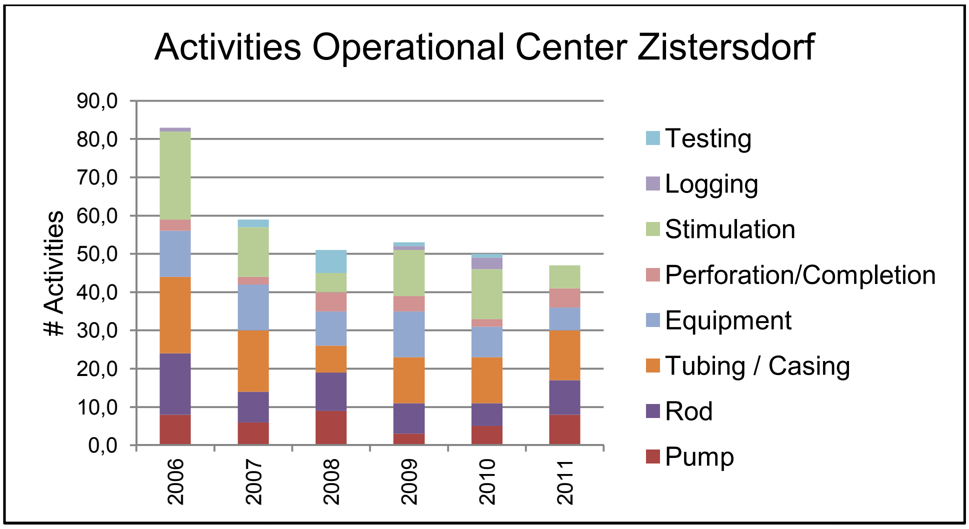

Figure 53: Activities within operational center Zistersdorf between 2006 and 2011.

3.3.6 Summary Failure and Routine Workover Analysis

The total number of workover decreased in average annually by 2.8%. The main driving factor for this decrease was a reduction in workover due to failure of equipment, which had in total a cumulative economic value € 3.27 MM. For routine workover operation a cumulative additional investment of € 3.18 MM was executed. In total savings and investment resulted in a positive cash flow of € 90,000 within 6 years. The expenditures remained constant in real terms over the last 6 years (see Figure 37).

This illustrates that new technology implementation does not necessarily need additional investment budget. The implementation should be performed initially on a small scale and verified, then increased gradually.

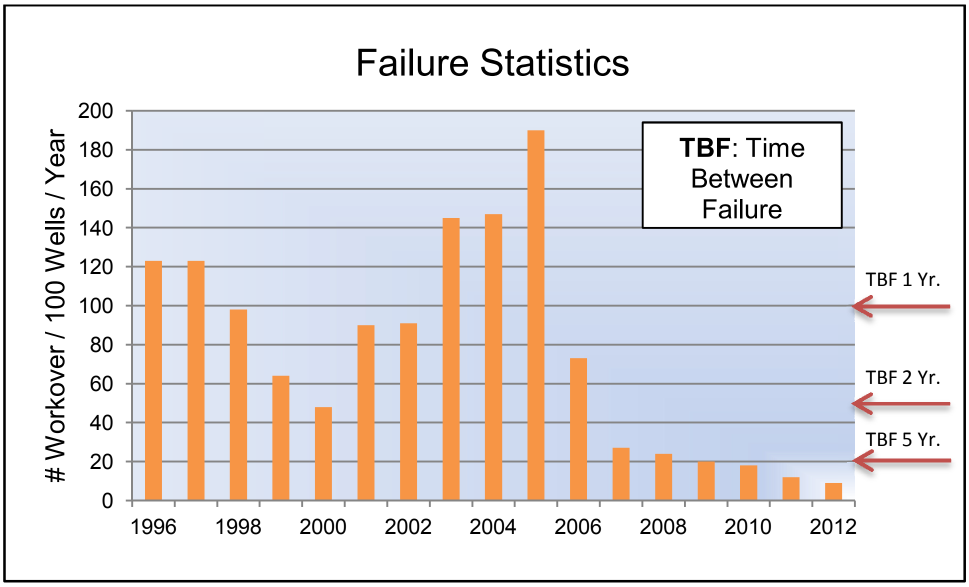

Figure 54: Failure statistics of operational center Zistersdorf.

Figure 54 shows the impact of technology on the number of workover operations due to failure. The number is normalized for the sake of comparison to a basis of failures per 100 wells. It can be seen that after 2005 the number of workover decreased dramatically. Comparing 2005 with 2012 would give a reduction of 20 fold within 7 years, leading to a hypothetical value of annually nine workover per 100 wells per year.

The mean time between failure (MTBF) is increased theoretically to 11.1 years. This is a high value, but equipment run times of over 10 years are reasonable. As mentioned above reducing the number of workover due to equipment failure provides the opportunity for new technology implementation and improvement of inflow performance. These actions result in additional production at a constant expenditure level.

3.4 Production Decline Analysis

3.4.1 General

One of the most important information for economical evaluation is the production decline behavior for the observed fields. From this behavior it is possible to identify future potential and current value of improvements. For this purpose a detailed analysis was performed for the whole operational center Zistersdorf. Both fields show different behaviors in oil and gas production as discussed below.

Gaiselberg field

From 2002 to 2005 oil production decline in the Gaiselberg field was in the range of 7.6% annually. After 2005 until 2008 the decline was nearly stopped, as a consequence of gradual technology implementation into the field. This situation was then changed and from 2008 to 2011, a production decline of 5.8% was observed.

The gas production had a decline of 11.2% from 2002 to 2004, followed by an increase of the rate of 13.8% from 2004 to 2007. Between 2007 and 2008 the production dropped by 33%, due to abandonment / closure of 2 wells. After this incident the gas production remained at a constant level till 2 gas wells where activated and an increase by 6% could be recorded. It has to be mentioned that the economic contribution of gas is only 5% to 8% of the overall revenue. More information is shown in Table 8.

GA	Production		Active Wells			
Year	Oil [t]	Gas [m^3]	Oil & Gas	Oil	Gas	Total
2002	30,062	2,330,933	27	0	1	28
2003	26,398	2,280,994	25	0	2	27
2004	22,826	1,528,172	26	0	0	26
2005	20,574	2,116,823	32	0	0	32
2006	20,585	2,507,841	28	0	1	29
2007	20,935	2,796,292	32	0	3	35
2008	22,148	1,852,129	34	1	1	36
2009	20,944	1,980,840	34	0	1	35
2010	16,688	1,985,320	34	0	0	34
2011	16,965	2,107,815	31	0	2	33

Table 8: Production data of Gaiselberg field between 2002 and 2011.

Rag field

The Rag field shows different behavior then the Gaiselberg field. From 2002 to 2005 the oil production decline was over 14% annually, resulting from shutting-in of several wells. After the gradual implementation of technology the oil production increased again similar as in Gaiselberg field and peaked in 2008. From this time the production decline was then 3.9% from 2008 to 2010. Afterwards a production increase of more than 20% was performed coming out of one new drilled well (RAG-052).

Rag field had a gas production decline of 5.5% between 2002 and 2006. In the following two years the production could be increased 41% per year as a result of 2 additional good performing gas producers. From 2008 to 2011 the decline was then 12.8% annually. The overall values are shown in Table 9. Any failure in one of the producers has a visible impact on the decline rate.

RAG	Production		Active Wells			
Year	Oil [t]	Gas [m^3]	Oil & Gas	Oil	Gas	Total
2002	3,133	201,005	5	0	1	6
2003	2,407	215,411	3	0	1	4
2004	2,080	152,811	3	0	1	4
2005	1,369	129,613	2	0	1	3
2006	1,713	145,519	3	0	1	4
2007	1,367	328,334	3	0	3	6
2008	2,225	851,069	4	0	3	7
2009	1,902	662,590	4	0	3	7
2010	1,961	467,297	6	0	1	7
2011	2,536	412,891	5	0	0	5

Table 9: Production data of Rag field between 2002 and 2011.

Figure 55 shows the split of the oil production of the Gaiselberg field and Rag field. The Gaiselberg field delivers 85% to 90% of the total oil production.

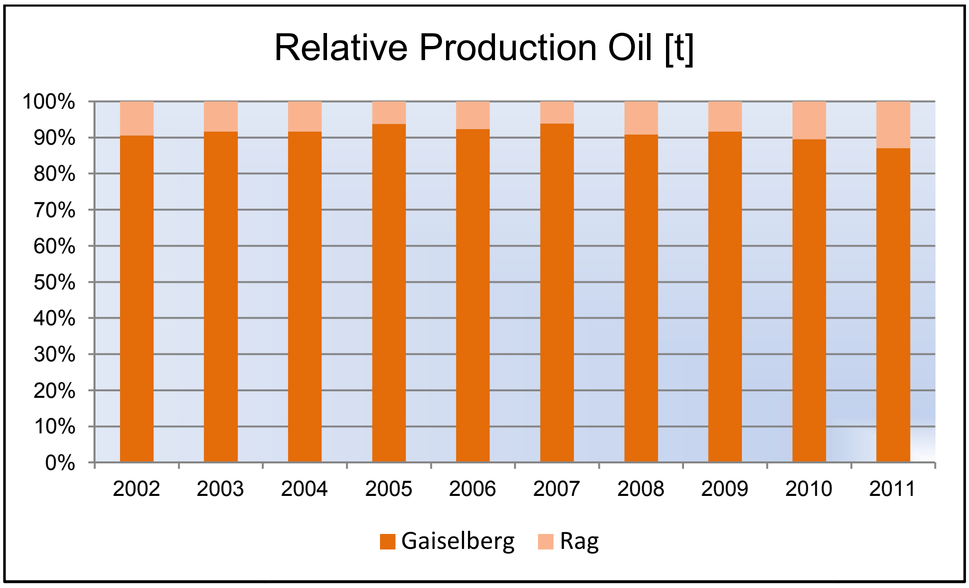

Figure 55: Relative production of oil in tonnes for operational center Zistersdorf.

For gas the situation is different as illustrated in Figure 56. The gas production from Gaiselberg field contributes between 68% and 95%. It is obvious that measures to improve the production are easier to implement in the Gaiselberg field unless a good opportunity is found in the Rag field, which would have a significant impact on the production performance.

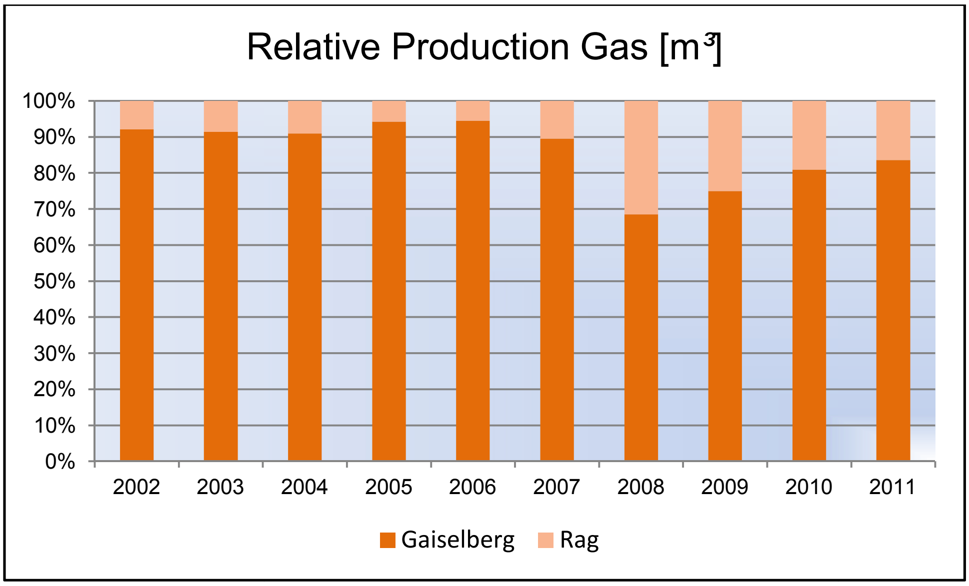

Figure 56: Relative production of gas in cubic meters for operational center Zistersdorf.

The calculation of the average oil production decline for both fields results in 6.8% annually from 1999 to 2005. By the application of the technologies described in chapter 2 an increase of the oil production in average of 2.5% from 2005 to 2008 was achieved annually. After that the production decline was stabilized at 4.9% annually, compared to 6.8% before 2005. This means the decline rate could be reduced by 1.9% annually. Taking all effects into account the average decline rate is balanced out at 4% over the total period analyzed, which is equal to an improvement of 40% (compared to 6.8%).

3.4.2 Production Decline Scenarios

The additional oil and gas production and thus the additional revenue generated from the technology application (chapter 2) is discussed and compared to 3 different decline scenarios (do-nothing cases, no new technology introduced). The scenarios are then compared to the historical recorded production data between 2006 and 2011. In Table 10 the specific decline values of analyzed scenarios are shown. The observed decline rate before 2005 was 6.8% therefore the spread between 5% and 9% was chosen to be representative.

Scenario	Decline[%]
A	5
B	7
C	9

Table 10: Decline scenarios with no technology application.

For the calculation of the additional revenue effectively achieved annual oil and gas price is taken into account. As seen in Table 11 the oil price is varying between € 277 and € 511 per tonne, which is an 85% price increase. Gas price was varying between ct 17 and ct 29 per m³. The prices are for the period between 2006 and 2011.

Year	Oil €/t	Gas €/m³
2006	330.65	0.25
2007	336.81	0.21
2008	426.70	0.28
2009	277.50	0.17
2010	383.07	0.21
2011	511.59	0.29

Table 11: Average achieved oil and gas price between 2006 and 2011.

3.4.3 Scenario A

Scenario A considers the optimistic theoretical production decline of only 5% compared to the historical decline starting in 2005. To get a better feeling for additional value generated, oil and gas production will be analyzed separately.

Additional oil production

Figure 57 shows the historical oil production compared to a theoretical oil production with 5% decline starting in 2005 (dark orange). The actual additional oil produced is ranging between 1450 tonnes to 5550 tonnes annually, as a difference to recorded production of technology scenario. The cumulative value of this additional oil (19460 tonnes) amounts to an additional revenue of € 7.4 MM. This means a cumulative increase in revenue of 16% between 2006 and 2011.

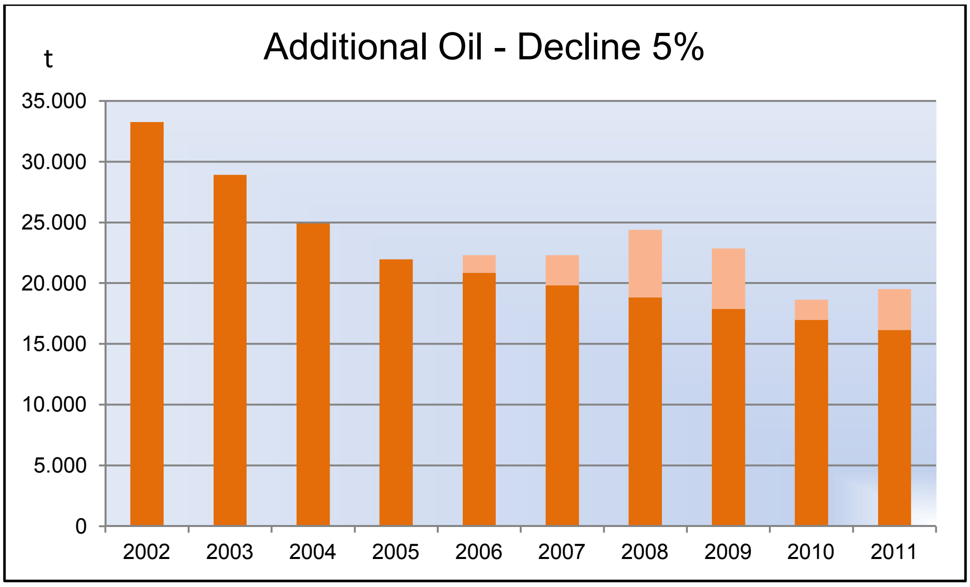

Figure 57: Additional oil production with a decline of 5%.

Additional gas production

The theoretical additional gas production with a theoretical decline of 5% is presented in Figure 58. Through technology implementation additional gas between 520,000 m³ and 1,100,000 m³ could be produced between 2006 and 2011. As for the case of oil the average achieved gas price per year has been taken for the calculation of the additional revenues.

The additional revenue achieved ranged between € 125,000 and € 250,000 annually. The cumulative achieved additional revenue between 2006 and 2011 was € 1.11 MM. This is a calculated cumulative increase of 42%.

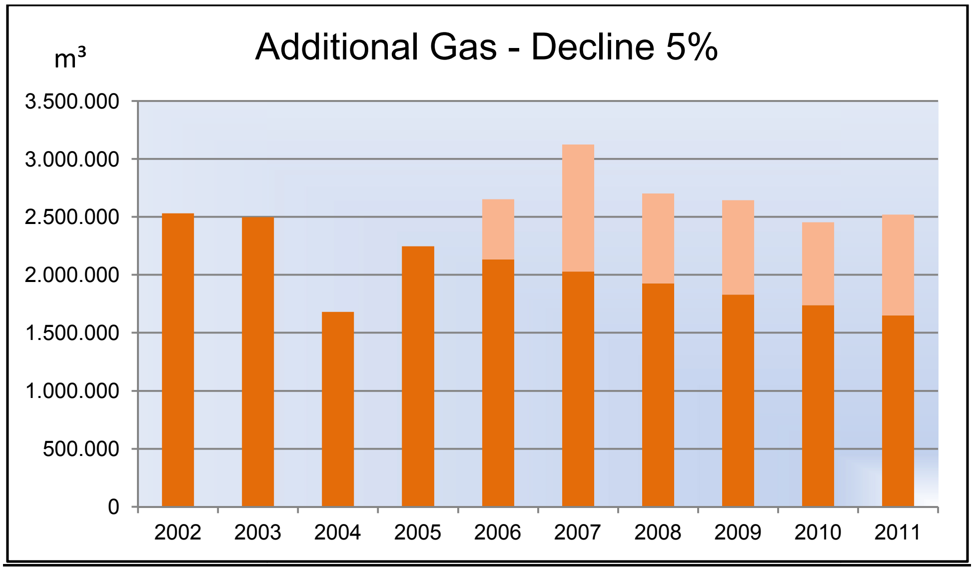

Figure 58: Additional gas production with a decline of 5%.

Scenario Summary

Year	Add. Oil [t]	Add. Revenue [€]	Add. Gas [m³]	Add. Revenue [€]	Total [€]
2006	1,441	476,381	519,246	127,831	604,212
2007	2,488	837,861	1,097,218	234,353	1,072,214
2008	5,549	2,367,905	777,160	214,296	2,582,200
2009	4,964	1,377,397	813,694	141,441	1,518,838
2010	1,661	636,144	714,368	148,937	785,081
2011	3,362	1,719,983	869,369	249,645	1,969,628
Total	**19,464**	**7,415,671**	**4,791,054**	**1,116,502**	**8,532,173**

Table 12: Calculations scenario A.

In Table 12 the additional oil generated compared to the historical data is shown. It can be recognized that the total additional revenue between 2006 and 2011 was ranging between € 600,000 and € 2.0 MM. The cumulative total revenue for additional oil and gas with the assumed theoretical decline of 5% in the do-nothing case amounts to € 8.532 MM. This is an increase of the cumulative revenue of 17%.

3.4.4 Scenario B (Realistic Scenario)

Scenario B considers the theoretical realistic production decline of 7%, which is very close to the historical decline of 6.8% before 2006. So it is in all probability a very realistic scenario, compared to scenario A which is somewhat optimistic and scenario C which is somewhat pessimistic.

Additional oil production

Theoretical oil production with an assumed 7% decline is presented in Figure 59 (dark orange) and compared to historical achieved oil production. The theoretical additional oil production generated in this scenario is ranging between 1900 tonnes and 6700 tonnes annually .The cumulative production is exactly 27000 tonnes for the period between 2006 and 2011.

Taking the average achieved oil price per tonne for each observed year into account would result in additional revenue of € 10.3 MM. This means a cumulative increase in revenue in the range of 25% between 2006 and 2011. This number represents a very good performance related to increase in revenue, due to fact that it is a realistic number. This had also a remarkable effect on the cash flow development, due to the fact that the expenditures of operational center Zistersdorf are kept on a nearly constant level as presented in chapter 3.2.

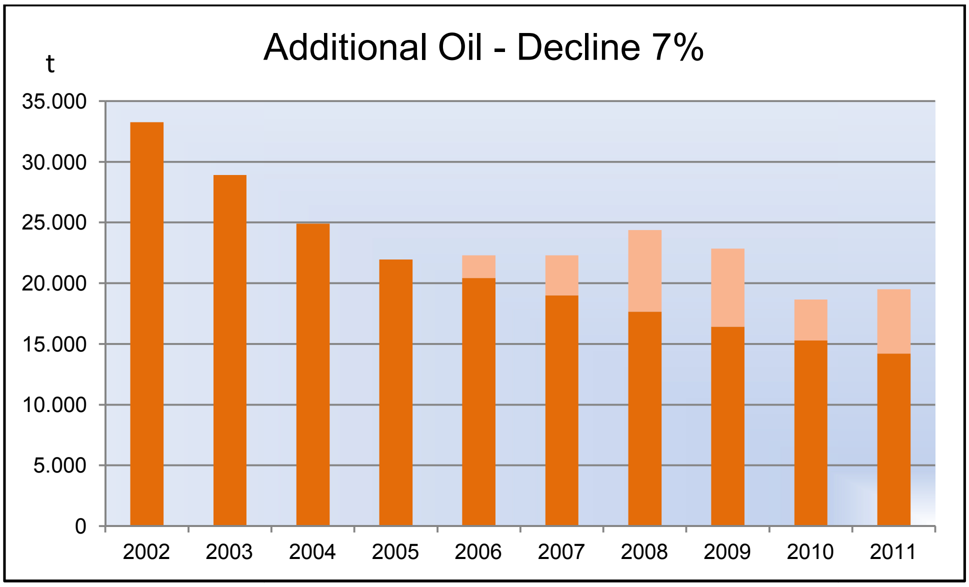

Figure 59: Additional oil production with a decline of 7%.

Additional gas production

Additional gas amounts generated annually in scenario B are presented in Figure 60. The extra gas production is ranging between 560,000 m³ and 1,200,000 m³. As conducted before the average achieved gas prices per cubic meter for each year are taken for calculations.

With the assumption of 7% theoretical gas decline annually the additional revenue generated is ranging between € 140,000 and € 300,000. Summed up additional revenue between 2006 and 2011 was € 1.3 MM. This value represents a cumulative increase in gas revenue of 52%. In general the focus of production is on the oil production, because almost 90% of revenue is coming out of it. Most of the produced gas is an associated gas.

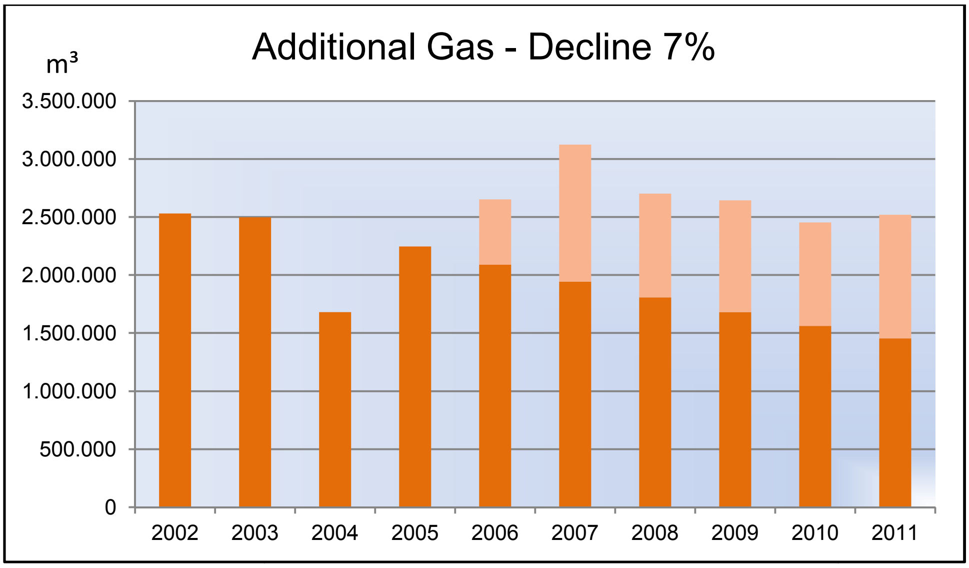

Figure 60: Additional gas production with a decline of 7%.

Scenario Summary

Year	Add. Oil [t]	Add. Revenue [€]	Add. Gas [m³]	Add. Revenue [€]	Total [€]
2006	1,880	621,569	564,175	138,892	760,460
2007	3,313	1,115,903	1,181,684	252,394	1,368,297
2008	6,713	2,864,589	896,261	247,137	3,111,726
2009	6,423	1,782,277	962,979	167,390	1,949,667
2010	3,375	1,292,930	889,798	185,512	1,478,442
2011	5,296	2,709,531	1,067,284	306,477	3,016,008
Total	**27,000**	**10,386,798**	**5,562,180**	**1,297,802**	**11,684,600**

Table 13: Calculations scenario B.

Annually revenue generated out of additional oil and gas production of scenario B is presented in Table 13. For this realistic scenario the values are ranging between € 760,000 and € 3.0 MM, resulting in cumulative extra revenue of € 11.684 MM between 2006 and 2011. This value is equivalent to an increase of revenue in the range of 28%, within 6 years and represents a remarkable performance of technology and engineers.

3.4.5 Scenario C

Scenario C is the most pessimistic once. Its main assumption is an overall production decline of 9% annually. Compared to historic decline before 2006 of 6.8%, this value is increased by 2.2%. It is important to have a range of values within the various scenarios, because nobody could reliably say what the real decline behavior could have been.

Additional oil production

Additional theoretical oil production calculated with the assumption of 9% oil production decline and compared to historical production, is ranging between 2300 tonnes and 7800 tonnes, compared to historical production. Cumulative extra production is 34000 tonnes for the period between 2006 and 2011. Calculating with the annually average achieved oil price per ton this scenario would end up with additional revenue of € 13.2 MM. This means a cumulative increase of 36%within 6 years.

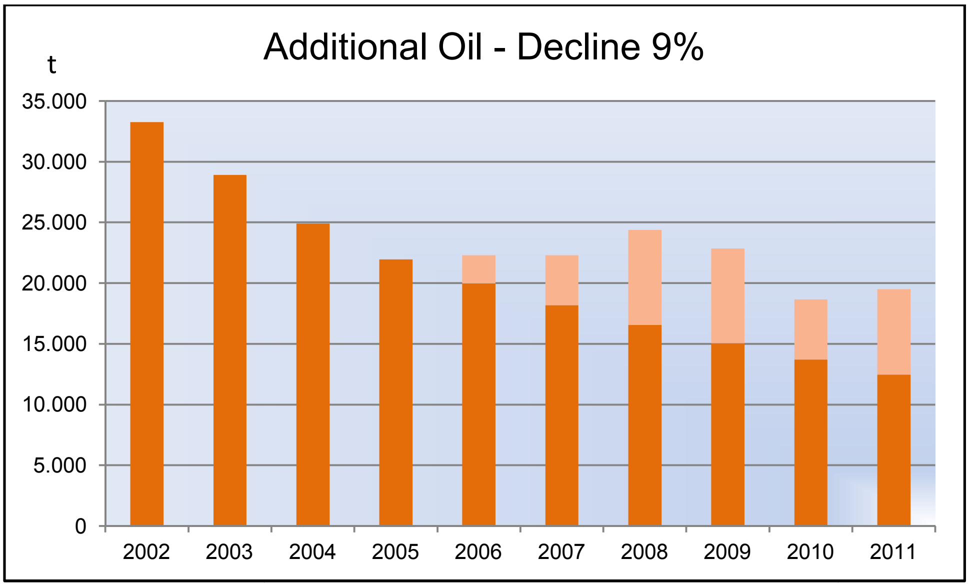

Figure 61: Additional oil production with a decline of 9%.

Additional gas production

Additional gas production presented in Figure 62 is ranging between 600,000 m³ and 1,300,000 m³. This would be equivalent to € 150,000 and € 350,000, taking achieved gas price for investigated period into account. An assumed decline of 9% would result in cumulative extra revenue of € 1.46MM, which is equivalent to an increase in gas revenue of 63%.

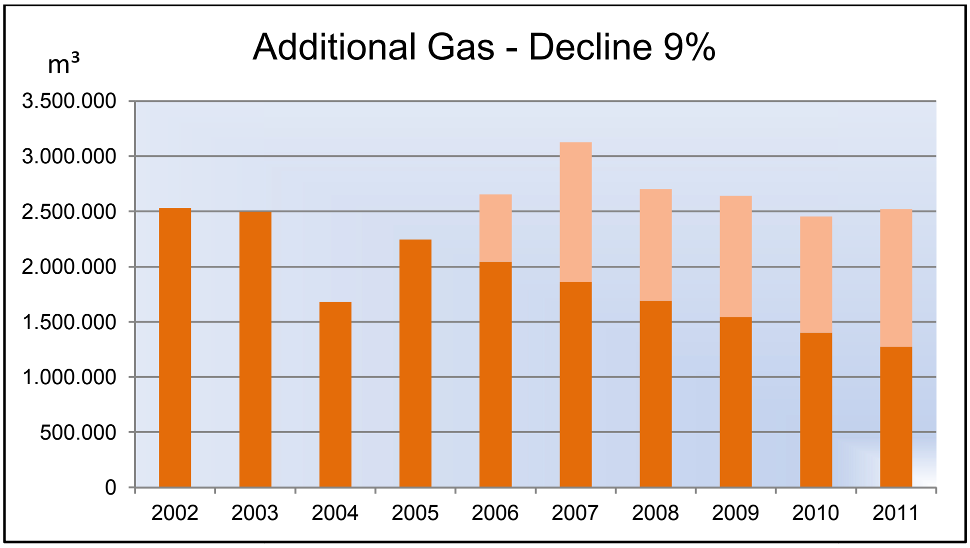

Figure 62: Additional gas production with a decline of 9%.

Scenario Summary

Year	Add. Oil [t]	Add. Revenue [€]	Add. Gas [m³]	Add. Revenue [€]	Total [€]
2006	2,319	766,756	609,103	149,952	916,709
2007	4,121	1,388,029	1,264,352	270,051	1,658,080
2008	7,828	3,340,363	1,010,349	278,596	3,618,959
2009	7,790	2,161,861	1,102,937	191,719	2,353,580
2010	4,948	1,895,583	1,050,769	219,073	2,114,656
2011	7,033	3,598,208	1,245,024	357,516	3,955,724
Total	**34,041**	**13,150,801**	**6,282,535**	**1,466,906**	**14,617,707**

Table 14: Calculations scenario C.

Looking at Table 14 the annual total values of revenue between 2006 and 2011 are presented. They are ranging between € 900,000 and € 4.0 MM. Cumulative total value would be € 14.6 MM, which is equivalent to an increase in revenue of approximately 38%.

3.4.6 Summary Production Decline Analysis

In Table 15 the additional revenues generated from the technology implementation compared to the do-nothing cases is shown. The values are between € 8.53 MM and €14 MM depending on the chosen decline scenario. This is equivalent to a cumulative increase in revenue of 16% to 38%.

Scenario B is closed to the observed historical production decline before 2005. Therefore this is the most realistic case. The cumulative extra revenues generated from this case amount to €11.7 MM or 28% increase in revenue between 2006 and 2011.

	Decline [%]	Additional Revenue [€]	Revenue Increase [%]
Scenario A	5	8,532,173	16
Scenario B	7	11,684,600	28
Scenario C	9	14,617,707	38

Table 15: Summary of production decline scenarios.

Annually oil and gas production rates for these three assumed scenarios are presented in Table 16. Annually extra oil production resulting from comparison of the technology case to the do-noting cases (3 assumed scenarios) range between 1441 tonnes and 7828 tonnes. For the gas production volumes are between 512,000 m³ and 1,240,000 m³.

Year	Scenario A		Scenario B		Scenario C	
	Oil [t]	Gas [m³]	Oil [t]	Gas [m³]	Oil [t]	Gas [m³]
2006	1,441	519,246	1,880	564,175	2,319	609,103
2007	2,488	1,097,218	3,313	1,181,684	4,121	1,264,352
2008	5,549	777,160	6,713	896,261	7,828	1,010,349
2009	4,964	813,694	6,423	962,979	7,790	1,102,937
2010	1,661	714,368	3,375	889,798	4,948	1,050,769
2011	3,362	869,369	5,296	1,067,284	7,033	1,245,024

Table 16: Additional oil and gas production of various scenarios.

3.5 Availability Analysis

3.5.1 General

Availability improvements have a large influence on the economics of production in mature fields. They influence decline due to increase or decrease of production rates for oil and gas wells. Engineers should try to achieve 97% availability for good wells, whereat the remaining 3% down time should be attributed to workover and maintenance operations. The availability of poorly performing wells is dependent on the mean time between failures (MTBF) and the availability of workover rigs. MTBF is a direct result of the quality of the equipment installed and the technology implemented in every single well. Rig availability could be improved by renting additional ones, failure prediction systems and improved workover schedules.

Figure 63 shows the average availability for all active wells (high and low performers) in operational center Zistersdorf between 2006 and 2011. The availability ranges between 81% and 89%. This leaves a theoretical potential between 11% and 19%, where the production could be maintained. The actual potential however is depending on mean time between failure (MTBF) of the equipment and thus the corresponding maintenance program.

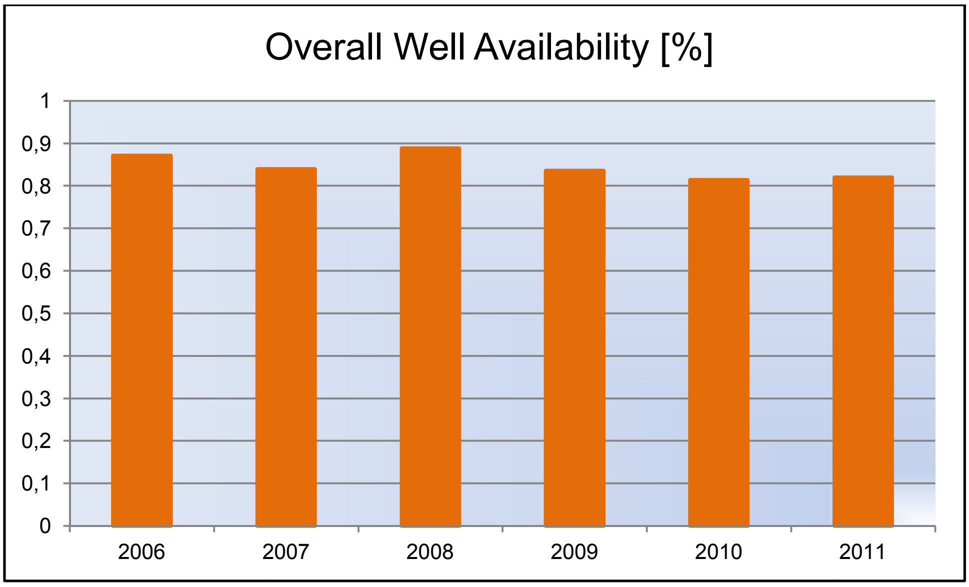

Figure 63: Availability of all wells in operational center Zistersdorf between 2006 and 2011.

The potential of availability concerning the theoretical lost oil production is calculated and shown in Figure 64. For the investigated period the lost oil production ranges between 3100 tonnes and 4500 tonnes annually. This is a cumulative theoretical lost production of 24000 tonnes of oil, corresponding to a cumulative value of € 8.9 MM or. 18.5% additional cumulative revenue within 6 years of production.

A 100% operational availability is however not realistic. Theoretical achieved hydrocarbon production due to availability improvement will be discussed in chapter 3.5.3.

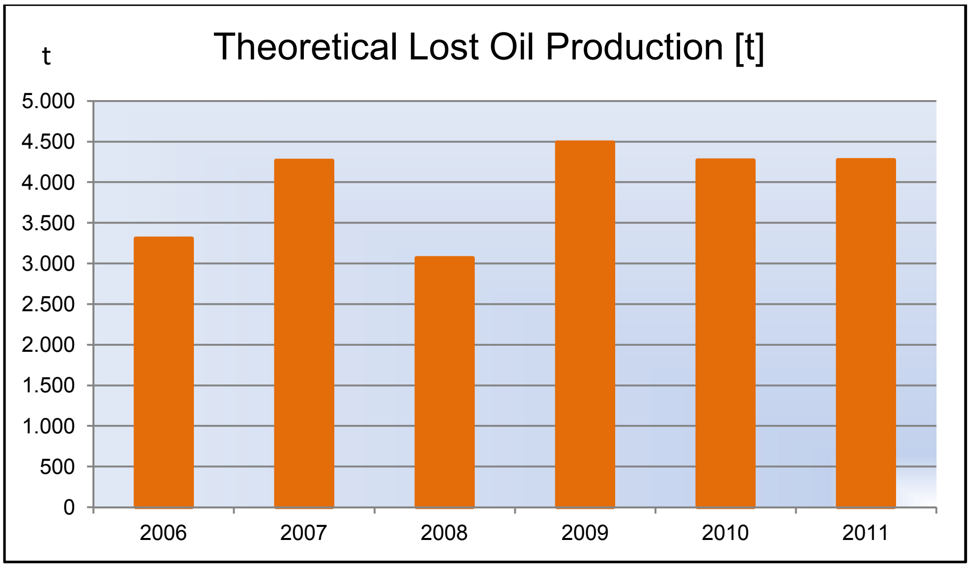

Figure 64: Theoretical lost production of oil due to availability between 2006 and 2011.

In Figure 65 the theoretical lost gas production is presented. The volumes are ranging between 340,000 m³ and 600,000 m³ annually. This results in a cumulative theoretical lost production of 2,960,000 m³, which is equivalent to € 685,000. As in the case of oil, this would be equivalent to a revenue increase of 18.5%.

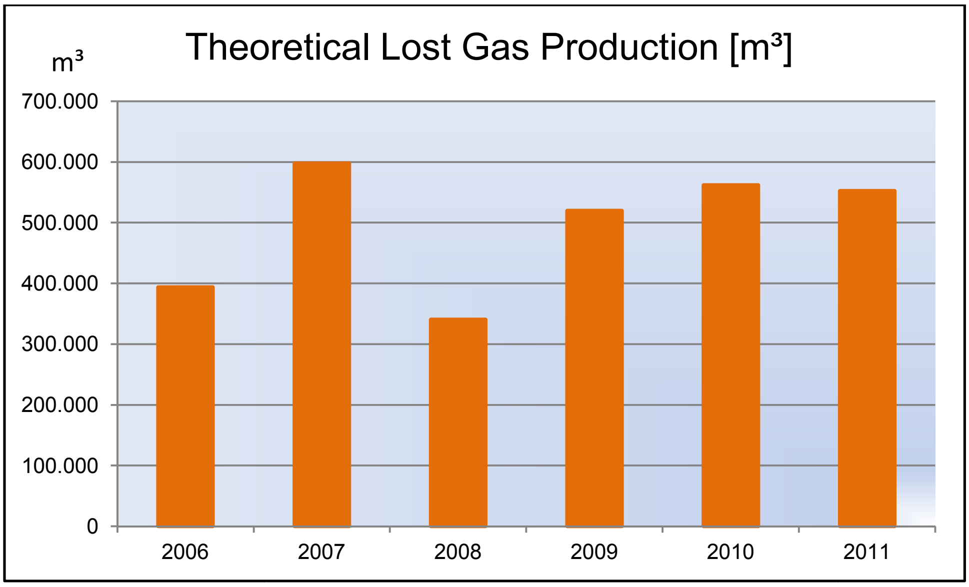

Figure 65: Theoretical lost production of gas due to availability between 2006 and 2011.

3.5.2 Detailed Availability Analysis

To get more detailed information about availability three categories are defined and shown in Table 17. These categories are:

- Wells with availability over 80%
- Wells with availability 40% and 80%
- Wells with availability under 40%

Availability / Year	> 80%		40% - 80%		< 40%	
	Number of wells	Average [h]	Number of wells	Average [h]	Number of wells	Average [h]
2006	30	8,369	1	5,945	2	1,267
2007	31	8,394	6	5,184	4	2,582
2008	36	8,523	3	5,835	4	2,553
2009	32	8,335	6	5,297	4	2,247
2010	31	8,511	5	4,543	5	1,139
2011	29	8,500	5	4,704	4	1,253

Table 17: Detailed results of availability analysis between 2006 and 2011.

Wells with availability over 80%

In Figure 66 the average value for wells with availability over 80% per year is shown. In this category the average value is ranging between 95% and 97%, which is remarkably good value for a mature field. The number of wells in this category is lying between 76% and 91% of the active wells. The number of wells with an availability of 100% is gradually increasing from 2006 to 2011, as shown in Figure 67. This is a direct result of investment and implementation of new technology. For this category no significant improvements are possible at this point in time, the focus is now directed to the other categories (investment to benefits ratio / additional production is too small).

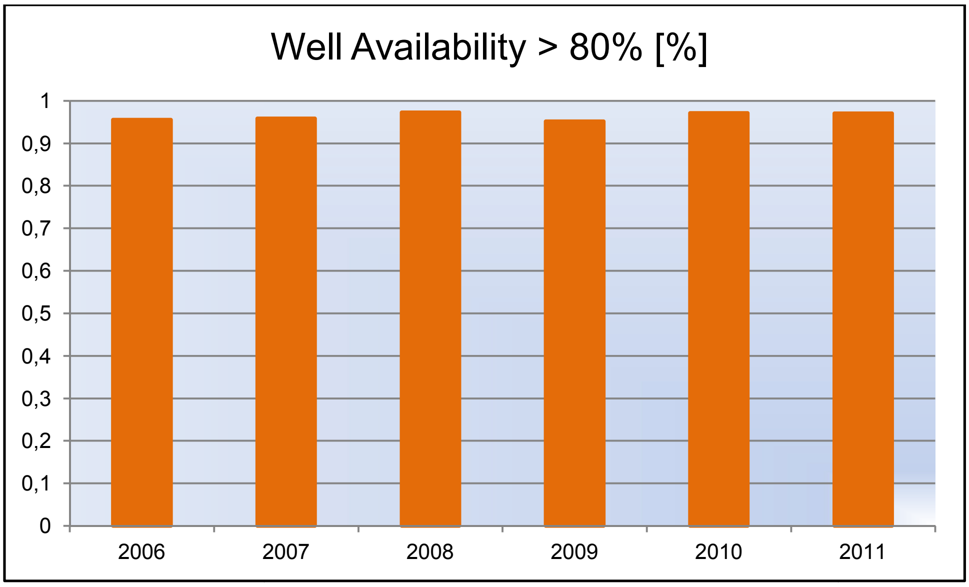

Figure 66: Wells with availability over 80%.

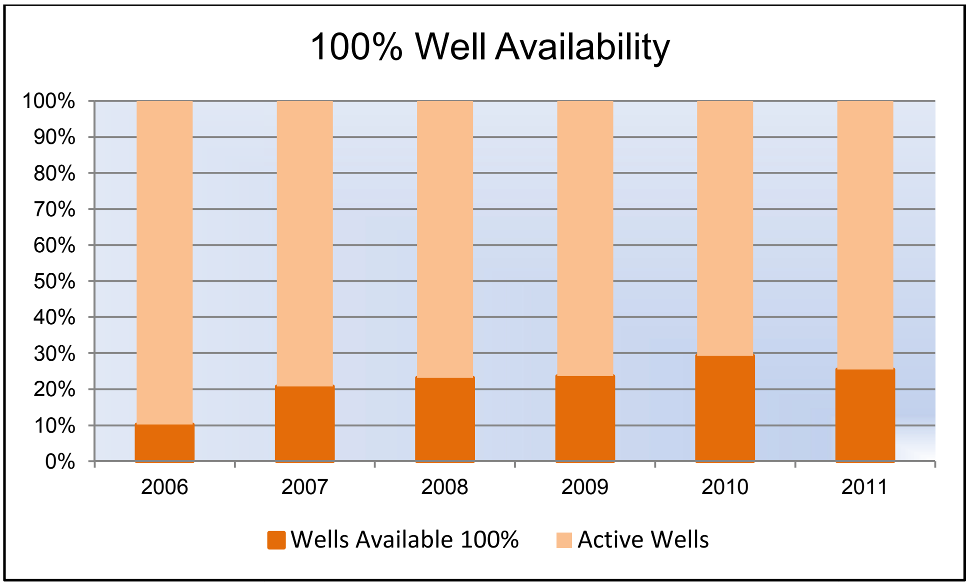

Figure 67: Number of wells with 100% availability between 2006 and 2011.

Wells with availability between 40% and 80%

The average values for availability in this category are between 52% and 68%, as illustrated in Figure 68. The number of wells operating with this performance (annually) is 1 to 6, which is equivalent to 3% to 15% of all active wells. The potential for improvements in this category is the highest, for several reasons:

- Wells are partly or not equipped with technologies mentioned before, see chapter 2.
- The observed production rates are good and an increase of mean time between failure by implementing the technologies would show a noticeable increase in production rates and thus in revenues.

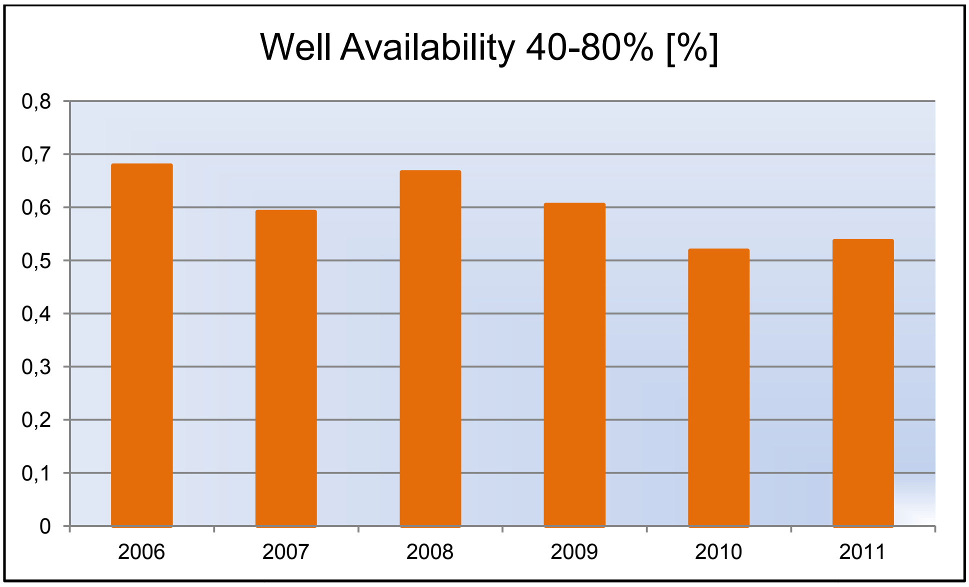

Figure 68: Wells with availability between 40% - 80%.

Wells with availability below 40%

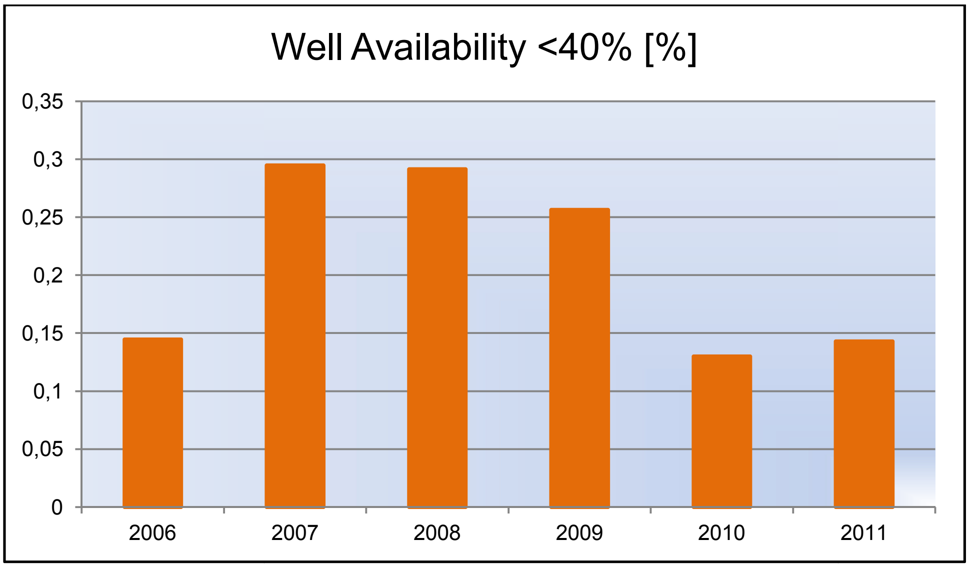

Figure 69: Wells with availability under 40%.

This category is showing the lowest availability between 14% and 29%. As shown in Figure 69. The portion of total wells lies between 6% and 12% annually. Most of these wells are poor producers, which are producing only intermittently for various reasons. From time to time some hydrocarbons are accumulated and can be produced. This category has theoretical the largest potential for additional production. However in many cases the condition of the wells is not example or the reservoir in production is fairly depleted so that additional investment have to be considered carefully, unless a new reservoir could be set on production in a particular well.

3.5.3 Summary Availability Analysis

Table 18 and Table 19 show theoretical additional production potential for oil and gas for each of the discussed categories.

Years	Theoretical Potential Oil [t]		
	> 80%	40% - 80%	< 40%
2006	7	1,416	1,884
2007	23	1,181	3,061
2008	8	1,181	1,880
2009	27	1,168	3,295
2010	14	1,516	2,740
2011	14	1,286	2,975
Total	**93**	**7,748**	**15,835**

Table 18: Theoretical availability potential for oil between 2006 and 2011.

Years	Theoretical Potential Gas [m³]		
	> 80%	40% - 80%	< 40%
2006	780	168,452	224,209
2007	3,275	165,478	428,808
2008	883	130,997	208,462
2009	3,108	135,137	381,199
2010	1,901	199,365	360,327
2011	1,834	166,209	384,492
Total	**11,781**	**965,638**	**1,987,497**

Table 19: Theoretical availability potential for gas between 2006 and 2011.

The calculations are standardized to the availability, the percentage of wells in each category and yearly production. Production improvements (where investment to benefit ratio is acceptable) could only be generated out of the category 40% - 80%. The potential for the cumulative additional revenue for oil would be € 2.93 MM and for gas € 225,000. Subtracting 10% for maintenance would result in total revenue of € 2.84 MM or additional 6% (Figure 70).

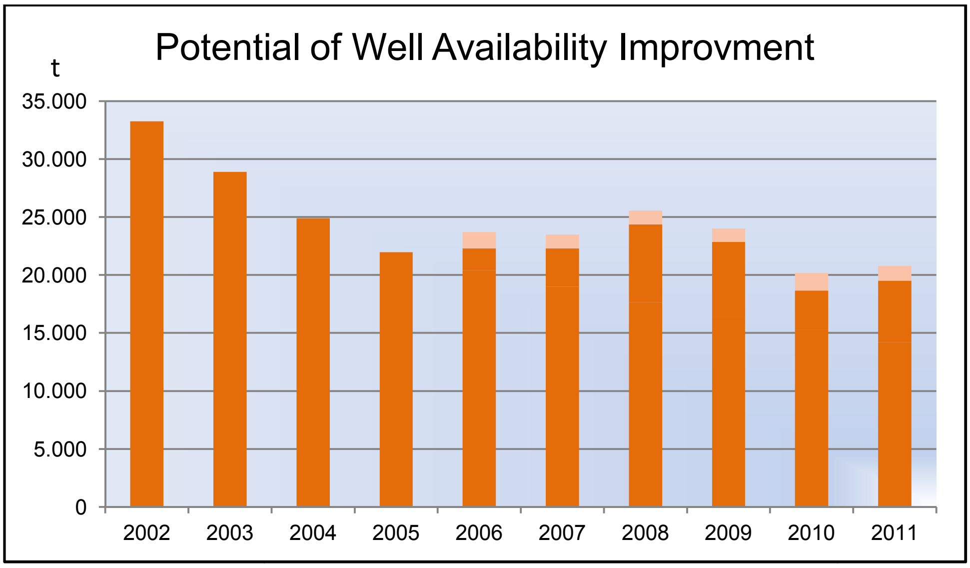

Figure 70: Potential availability improvement.

3.6 Marginal Cost Analysis

The economic future of the operational center Zistersdorf is depending on several factors:

- **Production rates / decline rate**: Before the application of new technologies in operational center Zistersdorf the average annual decline was in average 6.8%. After the implementation of new technologies and after an increase of production rates for 2 years the decline could be reduced to of 4.9% per annum till 2011. This shows that the implementation of new technologies helped to reduce the number of failures, thus increasing the MTBF, whilst keeping the OPEX constant.
- **Price development**: The change in market price of oil and gas is another parameter which is influencing the economics of the field. This parameter however cannot be influenced by operational center Zistersdorf or the company itself.
- **Expenditure development**: This development is dependent on numerous factors which are essential for operating a field. These factors can be divided into two main categories:
    - Capital expenditures; CAPEX
    - Operational expenditures; OPEX

In the following various scenarios will be discussed. They should demonstrate when operational center Zistersdorf would reach the economic limit of its operation. The scenarios B, C and D investigate three different oil and gas price developments (see Table 20). As reference for oil and gas price, the value of 2011 was taken. Reference for expenditures was also taken from 2011. All scenarios are calculated with a constant decline rate of 4%.

Scenario	Price Increase [%]
Low (B)	1
Moderate (C)	3
High (D)	5

Table 20: Price development scenarios.

3.6.1 Scenario A

In the hypothetical scenario A, no technology application is considered. Assuming that the benefits of the technology application started in 2006 an annual decline of 6.8% was taken into account. A second assumption is that cash which could have been used for investment in new technology and inflow improvement is used for execution of workover operation due to failures of subsurface equipment.

The result of scenario A is presented in Figure 71. It shows that the expenditure exceeds revenue in 2009 and 2010, resulting in a negative cash flow. In 2011 the revenues would have been higher than the expenditures however in regular oil field operations, a field with two years negative income would have been abandoned. This means operational center Zistersdorf theoretically would have had to be closed down in 2009 under the assumptions mentioned above.

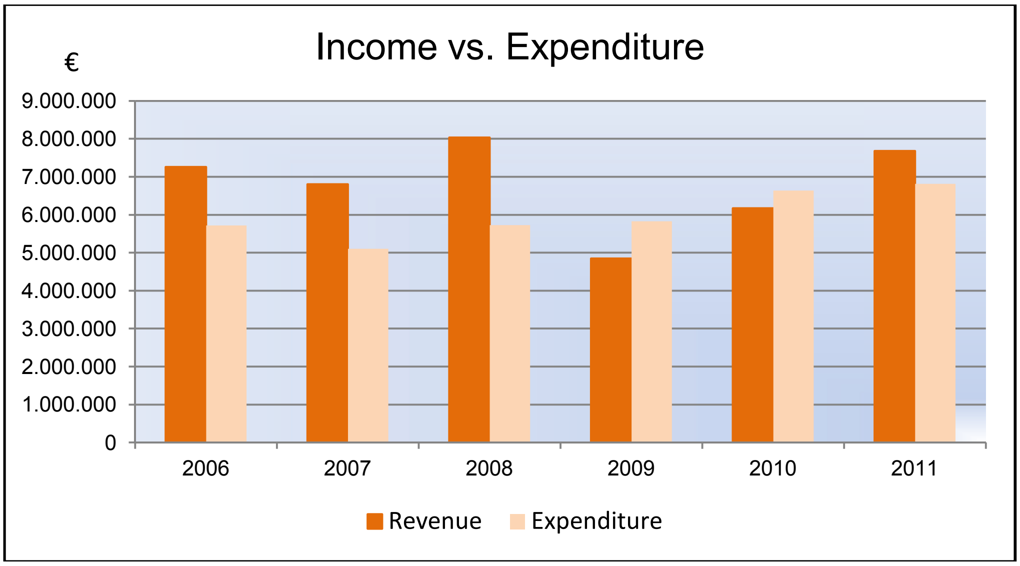

Figure 71: Graphical result of scenario A.

3.6.2 Scenario B

In scenario B an annual increase of the expenditures by 2.5% was taken into account. The considered value of 2.5% represents an average calculated from expenditure data between 2006 and 2011. Expenditures are kept constant in all scenarios; the increase reflects inflation development (see chapter 3.2.1). The oil and gas prices were taken with an annual increase of 1%. This is a pessimistic assumption, because the real term price development is actually 3.5%. The annual production decline rate was set to 4% (see chapter 3.4). In Figure 72 the result of this scenario is shown. It can be seen that the cash flow will become negative 2019. This scenario would theoretically generate an additional cumulative cash flow in the order of € 13.8 MM.

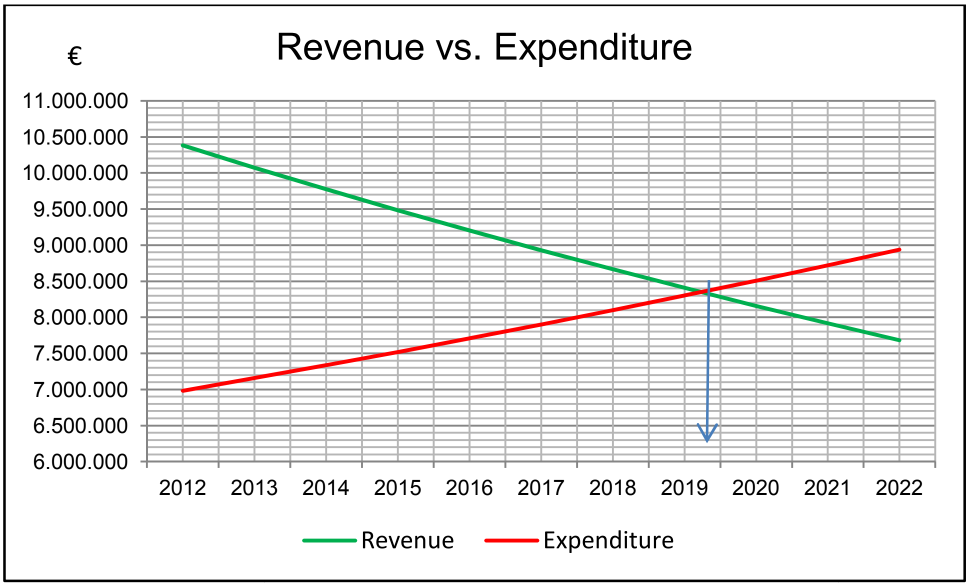

Figure 72: Graphical result of scenario B.

3.6.3 Scenario C

Scenario C represents the most realistic scenario under the chosen assumptions. Oil and gas price development is considered with 3% annual increase. This value is very close to the real term oil price development of 3.5%, analyzed between 1960 and 2012. In this scenario a negative cash flow would start in 2023. Basic assumptions for this scenario are the same as in scenario B. The additional cash flow would result in € 23.1 MM.

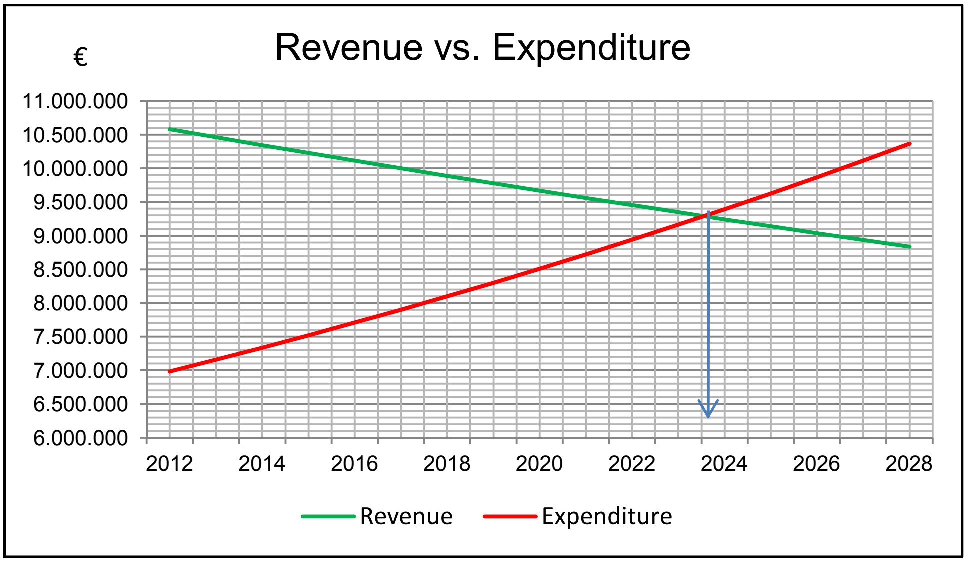

Figure 73: Graphical result of scenario C.

3.6.4 Scenario D

Scenario D represents an optimistic case with annual oil and gas price increase of 5%, annual constant production decline of 4% and annual expenditure increase of 2.5%. In this scenario the field life time is extended 2038, which means another 26 years and would generate an extra cash flow of the order of € 58.8 MM (money of the day).

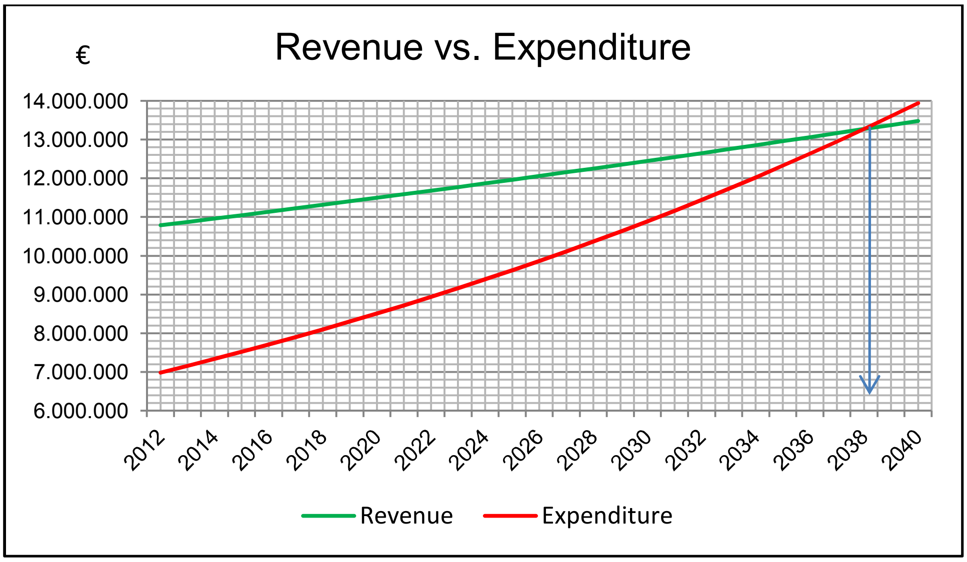

Figure 74: Graphical result of scenario D.

3.6.5 Framework Scenario

Scenarios B, C and D had two constant and one variable parameter:

- Constant production decline 4%
- Constant expenditure growth 2.5%
- Variable price development 1%, 3% and 5%

Figure 75 and Figure 76 show a framework in which the various parameters have been included and where more scenarios can be simulated. In Figure 75 various revenues and expenditures where plotted. In this case a constant decline rate of 4% was taken into calculation. The annual oil and gas price increase is varying between 1% to 5% and the expenditure increase from 2% to 3%, taking inflation development into account (expenditure level remains constant). The intersection points define the limit of the economic life time.

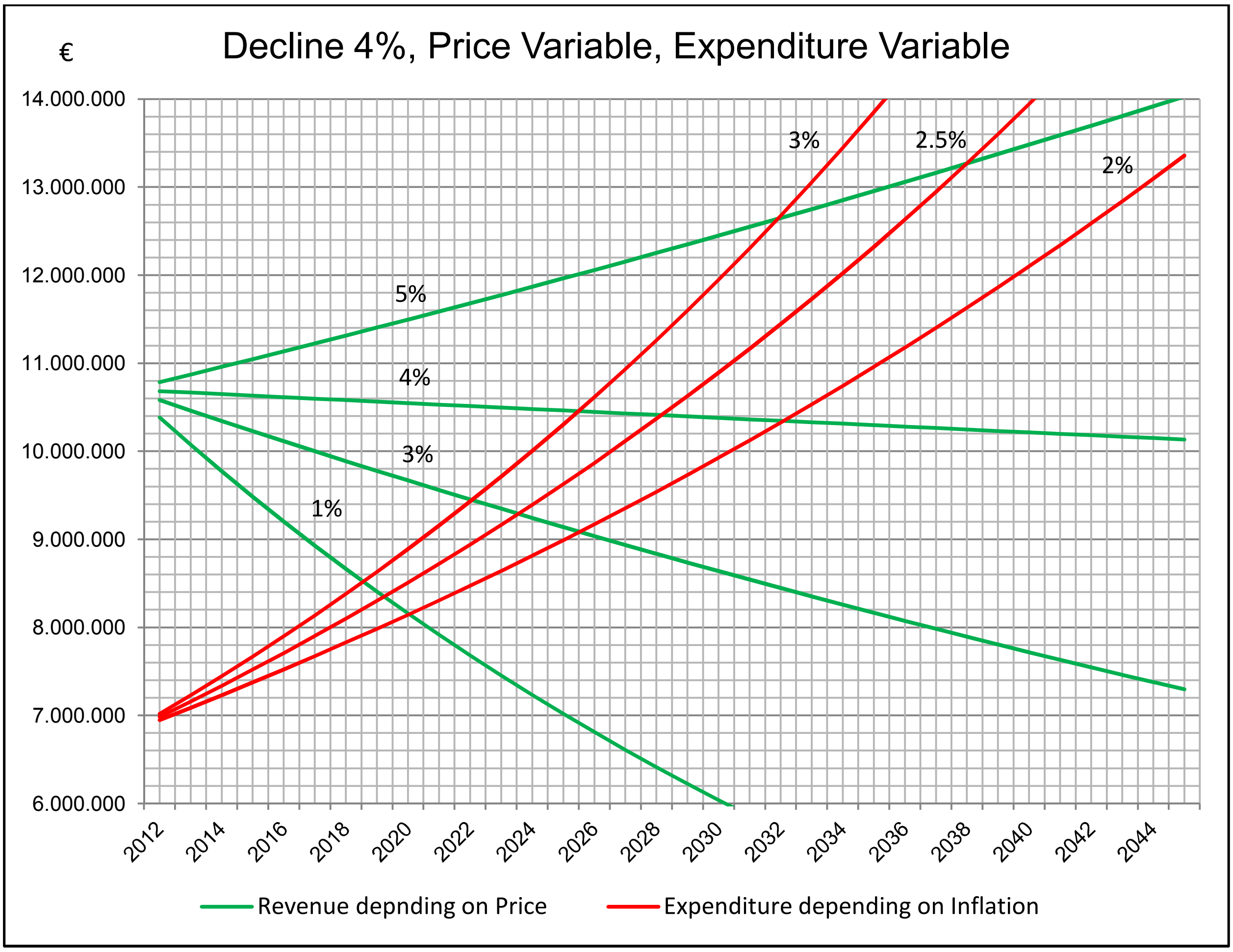

Figure 75: Real frame scenario A.

In Figure 76 also various revenues versus expenditures are plotted for comparison purpose. In this framework scenario the price development of oil and gas is kept constant. Variation of 3% to 5% in decline, thus revenue and variation of 2% to 3% in expenditure is shown.

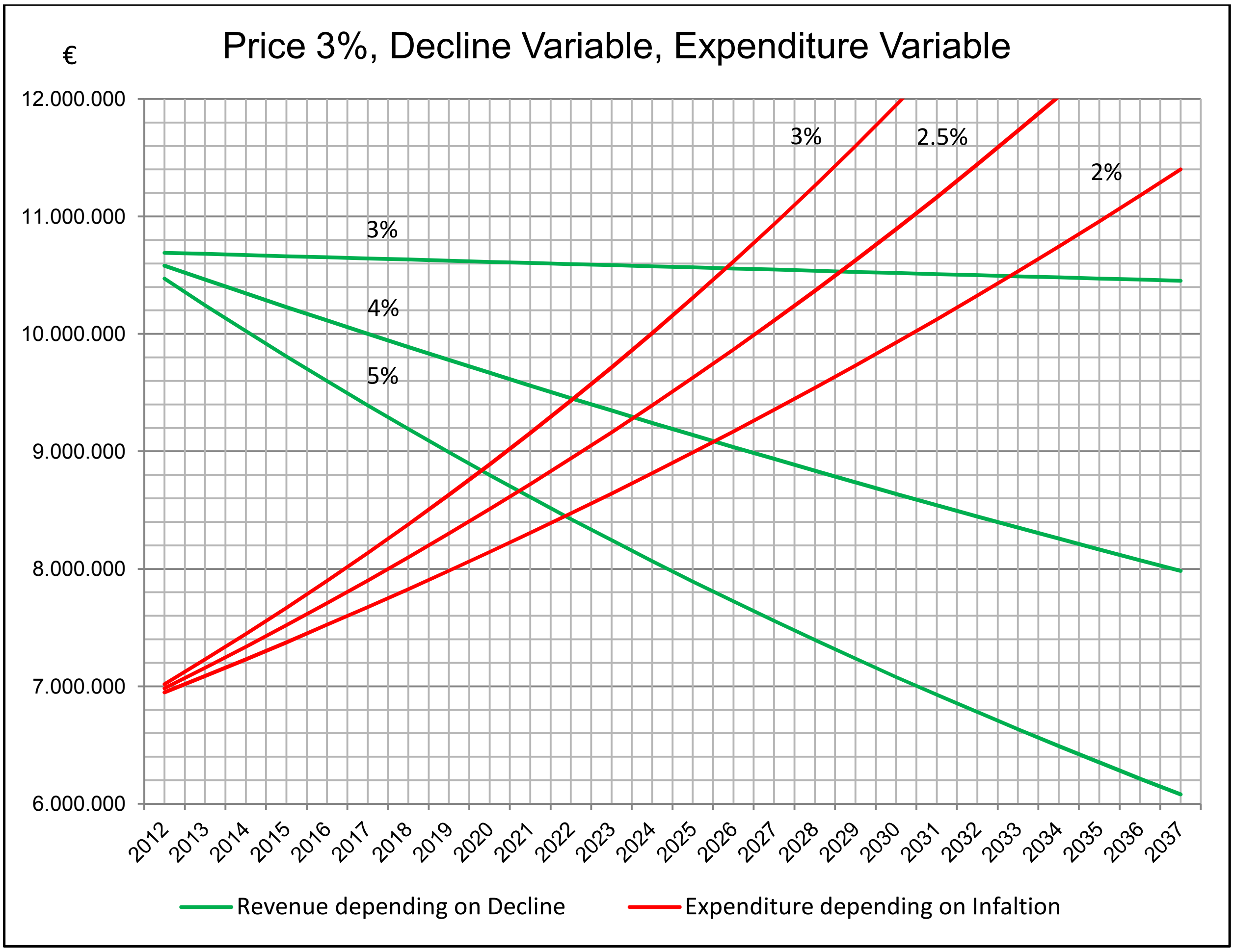

Figure 76: Real frame scenario B.

In Appendix B a couple of results with different combinations of parameters for both framework scenarios are presented.

3.6.6 Summary Marginal Cost Analysis

The economic life time of operational center Zistersdorf is - as mentioned in other chapters - depending on three main factors:

- Production decline
- Expenditure development
- Oil and gas price development

An overview for outcomes of different influence factors is shown in the following figure.

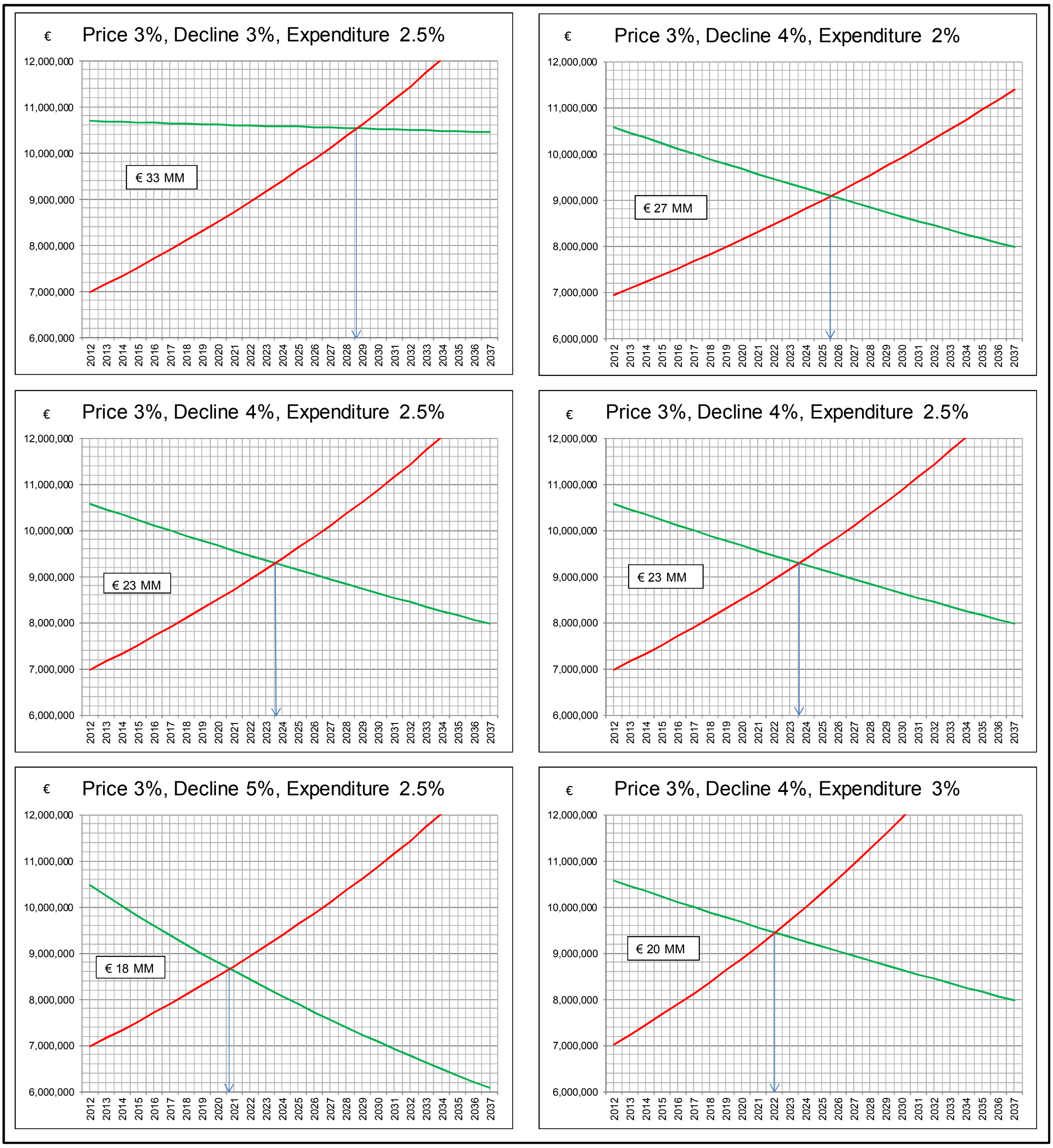

Figure 77: Scenarios in comparison.

In Figure 77 variations in production decline and expenditure are compared to each other. On the lift side decline is varied between 3%, 4% and 5%, with constant price growth of 3% and constant expenditure growth of 2.5%. On the right side expenditure is varied between 2%, 2.5% and 3%, with constant price growth of 3% and a production decline of 4%.

Comparing the size of the triangles on left side it can be noticed that the changes in size are very significant, thus influencing the cash flow negatively. On the right side it can be seen that the areas of the triangles are decreasing in a more moderate way.

In Table 21 values for the triangle area of the various scenarios of Figure 77 are shown:

Left Side [Million €]	Right Side [Million €]
32.8	26.8
23.1	23.1
17.9	20.1

Table 21: Economic value of cash flow triangles.

Interpretation of this information would result in the conclusion that production declines have a higher influence on cash flow development than expenditures. This means that activities that reduce the decline rate like the improvement of equipment run time and inflow performance generate the largest amount of cash flow. The result of this analysis shows that a reduction of the decline rate by 1% influences the economics of the field much better than a reduction by 1% of expenditures.

Of course the price development is also an important parameter. However companies have no influence on the market price under normal market conditions. This gives the following ranking:

1. Production decline
2. Expenditure development
3. Price development

The most realistic scenario of the analysis is C (see chapter 3.6.3). In this scenario duration of operational center Zistersdorf under economic conditions is till 2023. Assumptions are:

- Production decline rate of 4%
- Price increase for oil and gas of 3%
- Expenditure increase due to inflation of 2.5%

To achieve the same duration under economic conditions, with expenditure reduction, as in scenario C, the value of expenditure (reference 2011) has to be at least reduced annually by 3.35% over 12 years. For this case a decline of 6.8% (original decline) is assumed. This assumption is coming from the fact that saving lead to deterioration of the improved decline rate.

It has to be noticed that the decline could be even more influenced through savings, which means a higher annular reduction of expenditure has to be achieved, to result at the same economic duration as in scenario C.

In general it has to be mentioned that improvement in expenditure should be the second chose after decline improvement operations. The positive result of decline improvement also affects the expenditure development positivity, but otherwise is not the case. This could be proved by operational center Zistersdorf. Due to improvements in decline and better equipment, the rig expenditure will be reduced in near future, because only one shift is needed to fulfill the actual workover operations. This means a reduction of at least 30% in rig expenditures and 5% – 7% of overall expenditure.

4 Future Measure

As mentioned before economic value of technologies installed could not be assigned to one single technology, due the fact that numerous technologies mentioned before (chapter 2) were massively installed after proving performance on a small scale.

The sum of benefits of each single installed technology led to the success of operational center Zistersdorf. To perform even more specific analysis on each technology, RAG is now performing a systematic approach in 3 wells. In those wells technologies will be installed and monitored even more exactly as performed before.

5 Conclusion / Interpretation

The economic life time of the operational center Zistersdorf is of particular significance for RAG. Challenges operating the fields located at Zistersdorf (i.e. Gaiselberg field and RAG field) have increased gradually over decades due to the nature and maturity of the fields. Currently the average production from 33 producing wells is 6,900 m³/day of gas and 48 t/day of oil at an average water cut of 97.1%. Under these circumstances implementation of new technologies has to be performed carefully to ensure economic success.

To ensure a positive cash flow development, numerous new technologies have been introduced in both fields, with a concerted effort starting in 2005. Some of the technologies applied have been developed by RAG and its partners; examples are:

- MURAG: Continuous producing fluid level measurement & control system.
- Ceramic Sand Screen (CSS) as an alternative to conventional gravel packs.
- Electronic Controlled Rod Rotator (ECRR)

Others technologies are industry standard and have been adapted to be fit for mature field purpose. One of the technologies introduced, with the most significant influence was corrosion inhibition. Through the in-house expertise it was possible to select the most suitable corrosion inhibitor. It is important to note that in general, each new technology was tested on a small scale (2-3 wells) to prove the performance under operating conditions. After getting the conformation of success, the technologies were introduced gradually on a field scale. This controlled process had a considerable influence on the economic success. Through efforts, knowhow and technology implementation several positive effects were observable in the period investigated i.e. between 2006 and 2011:

- Reduction of workover operations due to failure of equipment.
- Increase in workover operations related to enhancement of inflow performance.
- Constant annual expenditure level.
- Increase in the number of on-stream wells.
- Reduction of annual production decline rates.
- Increase of economic life time.

An interesting observation is that the total number of workover decreased annually by 3%. The main driving factor for this decrease was the reduction in equipment failure workover. This is the direct result of the implementation of new technology, (21 workover in 2006 compared to 3 workover in 2012). This outcome had a total cumulative economic value (saving) of € 3.27 MM within 6 years. This resulted in additional availability of workover rig capacity. With these two benefits the possibility of additional workover operations enabling remediation of shut-in wells and programs related to inflow performance was created. The investments in such kinds of operations were € 3.18 MM between 2006 and 2011.

Comparing savings and investments values to each other shows almost zero additional investment, enabling the annual budget to be kept at a constant level and additionally improving i.e. decreasing annual production decline rates.

The technologies introduced increased mean time between failures (MBTF) to a theoretical value of 11.1 years, which is equivalent to 9 workover per 100 wells per year (e.g. 2012). In 2005 the rate of workover was 190 per 100 wells per year. This improvement shows impressively the benefits of suitable technology implementation and the possible savings potential.

To determine the additional revenue generated several production decline scenarios were simulated and analyzed. Values of parameters for calculating the scenarios were generated out of historical data. A certain variation of values was performed to cover possible uncertainties. In the most realistic scenario cumulative additional revenue of € 11.6 MM was determined. This is equivalent to a cumulative increase in revenue of 28% over the period of 6 years. It is emphasized that this was achieved without the need for additional budget funds.

One of the factors with the most influence on the economic life time of the operational center Zistersdorf is the production decline rate. This rate was reduced from a value of 6.8% annually before 2005 to 4% (in average) in the investigated period. This represents an improvement of approximately 40%.

Taking for a marginal cost analysis, the realistic value for production decline as 4%, the annual expenditure increase as 2.5 % and oil price development as 3% annually would result in a future additional cash flow of € 23.1 MM. Furthermore the economic life time of the operational center Zistersdorf will be extended by 12 years. Without the introduction of new technology a negative cash flow would have been generated in 2009 and 2010, resulting in the premature abandonment of these fields and leaving of producible reserves to the approximate value of € 30 million in the ground.

Ranking the most important factors related to positive cash flow generation and field life time of the operational center reveals the following:

1. Production decline
2. Expenditure development
3. Price development

Production decline has the greatest influence on all analyses performed and thus should be given top priority. Improving i.e. reducing the production decline rate can only be achieved by the implementation of new and proven technologies. After doing this, improvements in expenditure should be performed.

At RAG it has been shown impressively that the economic life time has been extended through intelligent and correct application of new technology in mature fields, guaranteeing jobs and a positive cash flow.

Gradual and justified investment into mature fields with suitable technologies to improve production decline rates is the right way to gain economic success and to increase ultimate recovery from the reservoir. A further benefit of such action is the decrease in future expenditures due to enhanced equipment performance such that the wells require only a minimal amount of workover operations.

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7 Appendices

7.1 Appendix A

	Förderung			2006	2007	2008	2009	2010	2011
829200	Förderung	471000	Bekleidung	2,541.10	1,223.12	4,602.21	4,368.44	482.51	172.75
829200	Förderung	474000	Bueromat	176.60	84.50	214.84	183.28	115.05	-
829200	Förderung	478000	Druckartikel/CD-ROM	-	-	45.55	-	-	-
829200	Förderung	480000	Fremdstrom (Kauf)	234,441.61	277,976.02	259,440.42	324,548.89	309,345.69	271,212.71
829200	Förderung	480100	Arb Energiesystem	-	-	-	-	-	1,933.24
829200	Förderung	481000	Erdgas (Kauf)	-	-	-	-	-	1,233.68
829200	Förderung	485000	Heizoel	-	-	28.33	-	-	-
829200	Förderung	486000	Benzin	52.10	25.93	20.84	-	-	30.66
829200	Förderung	487000	Dieselöl	-	4.94	14.24	-	45.50	193.54
829200	Förderung	500100	Bau - Div Arbeiten	292,532.93	179,298.95	256,557.47	143,145.41	65,327.59	87,832.32
829200	Förderung	500110	Überprüfungen	10,106.39	5,845.72	10,242.15	15,770.13	10,345.16	23,614.56
829200	Förderung	500120	Kor.schutz,Erhaltung	-	13,109.35	39,224.40	36,948.26	44,318.07	55,875.38
829200	Förderung	500200	Sonstige E-Arbeiten	50,819.78	18,708.88	49,147.47	30,281.83	20,706.34	27,412.88
829200	Förderung	500210	E-Überprüfungen	-	1,907.46	780.00	1,368.50	1,191.90	1,325.47
829200	Förderung	502000	Kranarbeiten	4,189.43	2,137.60	3,951.62	2,407.76	15,683.38	3,323.60
829200	Förderung	503100	Arb.mit Saugwagen	-	10,120.22	22,356.81	26,329.22	29,556.20	20,866.37
829200	Förderung	508000	Sonst.Transporte	8,469.20	32,587.92	34,887.01	50,788.30	39,577.44	53,230.50
829200	Förderung	524000	Slickline Service	-	-	-627.73	-	-	-
829200	Förderung	526400	SBH Winde	1,464.12	-	-	-	-	-
829200	Förderung	547000	Foerderzins FBZ	5,715.18	4,549.24	8,755.48	4,606.01	6,849.52	10,919.67
829200	Förderung	550000	Proj-Vermessung	-	-	-	515.51	419.03	3,195.51
829200	Förderung	551000	Bewirtungen	-	27.10	160.43	159.80	295.68	482.05
829200	Förderung	552000	Gutachten,Analysen	19,954.80	1,810.00	2,160.00	20,364.48	13,324.00	16,751.92
829200	Förderung	553200	Geraetemieten Ausl	-	-	2,335.50	-	-	-
829200	Förderung	553400	Sonstige Mieten	1,783.65	3,001.93	-	213.04	-	10.00
829200	Förderung	555000	Landw. Arbeiten	12,188.04	13,510.63	16,923.09	18,852.50	15,776.31	18,301.90
829200	Förderung	558000	Kontraktorpersonal	3,393.07	-	-	933.94	-	-
829200	Förderung	559000	Telekommunikation	-	-	144.00	-	-	-
829200	Förderung	560000	Postgebuehren	-	374.70	26.64	270.37	37.96	39.50
829200	Förderung	562000	Spenden-n abzugsf	-	-	1,096.91	-	-	-
829200	Förderung	565000	Entschaedigungen	345.33	876.86	32,956.64	140.00	133.06	-
829200	Förderung	572100	GSU-Training	-	-	-	-	-	103.70
829200	Förderung	579000	Sonst Leist,Kosten	248.19	2,505.70	4,534.83	1,657.11	1,828.22	2,331.93
829200	Förderung	579100	Div.Aufw.aus Handkas	-	-	28.67	-	-	-
829200	Förderung	581000	Betr Haftpflicht	3,800.00	2,000.00	5,000.00	-	12,000.00	4,662.00
829200	Förderung	581100	Betr Haft Selbstb	-	-	-	38,019.96	-	-
829200	Förderung	582000	Kfz-Haftpflicht	-	-	-	5,688.40	12,000.00	7,374.59
829200	Förderung	583000	Betriebsversich	5,500.00	-	-	-	12,000.00	23,764.43
829200	Förderung	592000	Grundueberlassung	29,105.43	31,065.29	662.45	32,477.67	33,191.99	31,725.73
829200	Förderung	593000	Freischurfgebuehr	3,120.00	3,120.00	3,120.00	3,120.00	6,526.00	5,434.00
829200	Förderung	599000	Sonst Abgaben	144.50	1,141.53	829.44	1,578.94	874.63	1,109.39
829200	Förderung	599100	Abfall - Entsorgung	19,037.99	5,279.24	16,454.23	10,820.88	3,907.46	11,762.65
829200	Förderung	600999	ILV/ELV-Personal	-	15,601.00	-	-	-	-
829200	Förderung	612010	V-Auftrag - Sanierun	16,057.38	48,774.08	150,494.51	103,866.59	170,672.35	-
829200	Förderung	612020	V-Auftrag - Optimier	3,387.57	57,894.05	36,621.88	-	-	157,783.23
829200	Förderung	612030	V-Auftrag - Replacem	33,975.02	-	-	-	-	
829200	Förderung	612040	V-Auftrag - GSU	-	17,377.59	-	-	-	
829200	Förderung	619001	Pettenbach Pers&Allg	15,120.00	16,380.00	5,520.00	-	-	
829200	Förderung	679999	ILV-Umb/Saldenausgl	21,480.77	-18,555.58	9,800.98	-16,464.76	-	
829200	Förderung	735000	Grundsteuer und Bode	-	-	-	319.40	-	-
829200	Förderung	L250	LV FBZ	477,194.30	528,113.01	490,587.85	514,133.77	462,649.72	549,715.34
829200	Förderung	L354	LV ET		270.84				697.36
829200	Förderung	L3541	LV Electr Maint	1,313.09	-	-	-	-	-
829200	Förderung	L523	LV ENG PA	1,099.72	-	-	-	-	-
829200	Förderung	L8001	LV E&P ÖL	9,053.35	4,609.06	-	-	-	-
829200	Förderung	U220	Fahrpark ZDF	10,861.10	8,612.15	16,713.00	18,111.67	6,346.98	18,579.47
829200	Förderung	U259	Telekommunik ZDF	6,627.95	6,162.63	3,923.65	3,535.69	8,645.92	567.20
829200	Förderung	U328	Well Survey	-	-	-	10,721.38	8,645.92	16,778.59
829200	Förderung	U3291	Erlöse Prod Eng	-	-	-	-225.00	-	-
829200	Förderung	U6999	Umb. Div. Kosten	-	-	-	-13,409.73	-	-
		Summe		1,305,299.69	1,297,531.66	1,489,735.81	1,396,147.64	1,312,819.58	1,430,347.82

Figure 78: Summary production expenditure.

	Winde			2006	2007	2008	2009	2010	2011
238000	Winde	526400	SBH Winde	941,549.09	930,336.70	965,616.87	962,909.08	890,790.37	956,983.50
		Summe		941,549.09	930,336.70	965,616.87	962,909.08	890,790.37	956,983.50

Figure 79: Summary workover rig expenditure.

	Personal			2006	2007	2008	2009	2010	2011
250000	Personal	410000	Arb-Grundlohn	2,360.51	3,840.84	2,327.73	4,746.67	3,200.00	4,701.33
250000	Personal	415000	Arb-Ges Soz Aufw	618.44	1,006.29	609.87	1,243.63	838.40	1,231.75
250000	Personal	420000	Ang-Grundgehalt	464,088.89	460,617.06	490,304.47	525,914.35	556,348.51	536,487.37
250000	Personal	420101	Arb/Ang Anerk.Prämie	-	4,250.00	-	-	-	-
250000	Personal	420200	Ü-Std u Normalstdzus	28,506.36	27,140.36	29,781.23	30,825.37	30,123.58	28,607.92
250000	Personal	420400	Ang-Sonst Entgelte	63,702.16	96,148.59	85,331.56	85,132.72	86,643.96	82,928.32
250000	Personal	421100	Ang-Trennungskost	263.06	444.54	-	-	-	-
250000	Personal	425000	Ang-Ges Soz Aufw	133,194.76	130,628.57	132,847.61	141,565.80	149,187.06	137,073.25
250000	Personal	428000	Reisekosten	8,621.63	3,664.85	2,786.68	14,263.11	1,636.28	267.40
250000	Personal	428100	Kilometergeld	8,463.46	8,186.10	7,789.69	8,021.97	5,255.04	4,218.90
250000	Personal	428300	Flugkosten	-	-	-	-	-	290.67
250000	Personal	428400	Taxikosten	-	-	-	-	-	66.36
250000	Personal	428500	Hotelkosten	-	-	-	-	-	149.01
250000	Personal	434000	Beitraege an MVK	-	-	-	-	3,714.58	3,172.52
250000	Personal	436000	Sonst Aufw-ÖBB-Busin	-	-	-	96.00	96.00	-
250000	Personal	437000	SonstAufw-Mietw.ARAC	-	-	-	-	950.42	225.43
250000	Personal	438000	Sonst Aufw -Overhead	2,081.46	-	-	-	-	-
250000	Personal	450000	Mech. Material	406.37	712.20	43.87	1,438.85	352.60	175.84
250000	Personal	450200	E/MSR-Material	-	-	10.42	94.21	-	-
250000	Personal	450300	Chem. Arbeitstoffe	-	-	-	184.30	-	-
250000	Personal	456000	Tubing	-	-	-	-	-	59.00
250000	Personal	470000	Lebensmittel	653.26	572.52	689.89	657.96	1,691.39	2,308.95
250000	Personal	471000	Bekleidung	-	233.28	79.34	1,051.94	292.08	1,995.50
250000	Personal	474000	Bueromat	3,102.57	1,853.71	993.15	2,185.13	1,359.77	808.01
250000	Personal	475000	Ersatz Computerperip	-	-	194.68	389.36	389.36	3,131.39
250000	Personal	478000	Druckartikel/CD-ROM	22.27	-	15.00	177.19	33.27	-
250000	Personal	480000	Fremdstrom (Kauf)	1,093.71	1,070.01	1,351.15	1,535.35	1,535.35	1,890.80
250000	Personal	481000	Erdgas (Kauf)	771.20	246.94	394.30	420.99	-344.66	-
250000	Personal	486000	Benzin	-	-	16.01	-	10.00	-
250000	Personal	487000	Dieselöl	21.67	-	-	-	-	-
250000	Personal	500100	Bau - Div Arbeiten	8,671.95	5,490.26	-	3,162.84	73.40	-
250000	Personal	500110	Überprüfungen	-	-	251.22	125.02	117.25	270.17
250000	Personal	500200	Sonstige E-Arbeiten	352.78	-	-	206.54	288.47	-
250000	Personal	503100	Arb.mit Saugwagen	-	-	981.15	712.05	-	-
250000	Personal	508000	Sonst.Transporte	90.23	-	-		1,171.76	-
250000	Personal	540000	Transporte Oel Prod.	-	59.62	-	-	-	-
250000	Personal	551000	Bewirtungen	593.73	1,647.91	2,448.23	2,686.17	2,953.28	5,938.59
250000	Personal	551100	Bewirt Firmafremde	2,406.76	623.57	-	-	-	-
250000	Personal	551200	Repraesentationen	46.80	-	-	-	-	-
250000	Personal	553100	Büromieten	2,760.00	2,415.03	2,300.04	2,300.04	2,300.04	2,300.04
250000	Personal	553400	Sonstige Mieten	778.33	783.72	1,175.58	1,690.04	1,537.44	1,537.26
250000	Personal	558000	Kontraktorpersonal	1,025.00	8,308.99	39,081.22	46,984.20	12,934.21	53,699.66
250000	Personal	559000	Telekommunikation	-	-	1,001.07	1,325.71	3,973.39	860.17
250000	Personal	559100	Mobiltelefone	-	-	-	-	1,434.53	2,725.13
250000	Personal	559200	Datendienste	-	-	-	-	157.07	429.75
250000	Personal	560000	Postgebuehren	4,591.29	3,288.19	341.89	280.46	264.03	669.36
250000	Personal	561000	Rechts-Pruefungsk	3,150.00	1,276.25	1,923.17	731.88	2,282.50	618.30
250000	Personal	562000	Spenden-n abzugsf	-	1,146.40	608.00	400.00	1,004.00	1,004.00
250000	Personal	563000	Spenden-abzugsf	-	-	-	256.00	-	296.00
250000	Personal	572000	Schulungen,Kurse,Sem	5,879.21	3,720.69	7,071.42	6,959.19	2,815.67	2,502.80
250000	Personal	572100	GSU-Training	-	1,854.50	393.88	-	68.65	352.73
250000	Personal	572200	Tagungen,Konferenzen	311.17	696.73	3,403.68	2,978.06	336.16	122.00
250000	Personal	572400	Reisekosten f. Train	-	-	-	-	-	556.32
250000	Personal	579000	Sonst Leist,Kosten	1,563.59	4,409.50	14,899.07	21,646.17	27,590.00	19,344.08
250000	Personal	579100	Div.Aufw.aus Handkas	-	22.91	2,633.91			9.60
250000	Personal	599000	Sonst Abgaben	4,967.09	3,171.18	288.99	582.38	1,399.19	4,144.23
250000	Personal	599100	Abfall - Entsorgung	302.81	303.36	594.49	1,568.91	923.16	475.82
250000	Personal	600999	ILV/ELV-Personal		-18,351.00	-	-	-	-
250000	Personal	679999	ILV-Umb/Saldenausgl	-32,313.38	-	-17,004.04	24,587.57	-59.49	-
250000	Personal	699998	Man Umb - LV	-	-	-884.88	-	-	-
250000	Personal	735000	Grundsteuer und Bode	-	-	-	56.32	-	-
250000	Personal	L3541	LV Electr Maint	691.10	-	90.14	-	-	-
250000	Personal	L354	LV ET	-	-	-	420.56	-	-
250000	Personal	L357	LV BOB	-	-	2,312.26	359.31	-	-
250000	Personal	L523	LV ENG PA	463.04	2,012.96	-	-	-	-
		Summe		724,303.28	763,496.63	819,477.14	939,964.32	906,877.70	907,645.73

Figure 80: Summary staff expenditure.

	Liquidierung			2006	2007	2008	2009	2010	2011
700829	Liquidierung	579900	Dot.RST Sondenliquid	791,950.00	227,055.58	191,369.52	220,731.80	823,949.06	823,949.06
		Summe		791,950.00	227,055.58	191,369.52	220,731.80	823,949.06	823,949.06

Figure 81: Summary abandonment expenditure.

	Sonstige Aufwendungen			2006	2007	2008	2009	2010	2011
107004	Sonstige Aufwendungen	763373	Liquid-Aufwand - ÖL	-	-	-	73,533.39	169,286.19	178,718.84
107004	Sonstige Aufwendungen	765000	Verschiedene Betrieb	-	-	-	-	306,500.00	-
259000	Telekommunikation	450000	Mech. Material	-	441.37	-	-	-	-
259000	Telekommunikation	559000	Telekommunikation	6,647.43	6,450.42	3,843.34	1,816.15	1,714.01	872.63
259000	Telekommunikation	559100	Mobiltelefone	3,549.46	2,589.21	2,193.10	3,623.39	1,131.18	-
259000	Telekommunikation	559200	Datendienste	-	-	-	-	347.80	-
222000	Fahrpark	571000	Mitgliedschaften	-	-	-	-	82.35	77.58
222000	Fahrpark	579000	Sonst Leist,Kosten	4.92	-	-	57.82	105.84	54.92
222000	Fahrpark	579100	Div.Aufw.aus Handkas	64.91	6.42	-	-	-	-
222000	Fahrpark	599000	Sonst Abgaben	303.96	66.83	-	-	-	-
222000	Fahrpark	820020	Erl.f. weiterb. Eige	-	-	-	-1,250.00	-	-
	Summe			10,570.68	9,554.25	6,036.44	77,780.75	479,167.37	179,723.97

Figure 82: Summary of other expenditures.

	Station			2006	2007	2008	2009	2010	2011
829100	Station	450200	E/MSR-Material	5,151.07	-	-	-		-
829100	Station	450300	Chem. Arbeitsstoffe	-	52.76	-	-		-
829100	Station	502000	Kranarbeiten	-	-	186.75	-		-
829100	Station	508000	Sonst.Transporte	157.36	-	164.96	-		-
829100	Station	551000	Bewirtungen					21.42	-
829100	Station	558000	Kontraktorpersonal	-	-	-	-		-
829100	Station	583000	Betriebsversich	-	6,000.00	-	-		-
829100	Station	592000	Grundueberlassung	-	-	-	907.73		-
829100	Station	612010	V-Auftrag - Sanierun	-	-	-	-	111,197.98	-
829100	Station	612080	V-Auftrag - OPEX	-	-	-	-	-	100,807.33
829100	Station	U305	Fernwirksystem	-	-	-	9,096.60	8,356.72	9,097.38
	Summe			5,308.43	6,052.76	351.71	10,004.33	119,576.12	109,904.71

Figure 83: Summary station expenditure.

	Schlammdepot			2006	2007	2008	2009	2010	2011
291000	Schlammdepot	565000	Entschaedigungen	-	39.78	-	-	-	-
291000	Schlammdepot	572200	Tagungen,Konferenzen	-	-	300.00	-	-	-
291000	Schlammdepot	579000	Sonst Leist,Kosten	-	-	-	76.23	-	-
291000	Schlammdepot	592000	Grundueberlassung	-	-	-	-	-	16.71
291000	Schlammdepot	599000	Sonst Abgaben	-	-	-	611.30	-	-
291000	Schlammdepot	612009	V-Auftrag - man.Buch	-26,024.39	-	-	-	-	-
291000	Schlammdepot	612010	V-Auftrag - Sanierun	26,024.39	17,502.50	-	-	-	-
291000	Schlammdepot	679999	ILV-Umb/Saldenausgl	1,055.05	-924.32	-	-	-	-
291000	Schlammdepot	L250	LV FBZ	17,947.44	20,469.16	13,851.03	9,957.98	22,221.29	12,848.99
291000	Schlammdepot	L7001	LV SGE SPEICHER & LO	690.00	-	-	-	-	-
	Summe			19,692.49	37,047.34	13,851.03	10,569.28	22,221.29	12,865.70

Figure 84: Summary mud deposit expenditure.

	Abschreibung			2006	2007	2008	2009	2010	2011
829080	Abschreibung	687000	Kalk. AfA Anlagen	377,975.02	307,389.11	347,937.77	-	-	3,391.07
829080	Abschreibung	687100	Großreparaturen	90,427.18	87,166.89	96,061.34	-	-	-
829080	Abschreibung	688000	Kalk. AfA Sonden	136,776.00	136,777.00	136,776.00	-	-	-
829200	Förderung	687000	Kalk. AfA Anlagen	-	-	-	363,244.97	363,666.99	414,296.11
829200	Förderung	687002	Kalk. Abschreibung v	-	-	-	-	45,592.00	-
829200	Förderung	687100	Großreparaturen	-	-	-	15,899.14	27,898.24	4,716.60
829200	Förderung	688000	Kalk. AfA Sonden	-	-	-	136,777.00	252,464.75	538,302.92
829200	Förderung	688002	Kalk. Abschreibung v	-	-	-	-	-45,592.00	-
829800	Oil FBZ OFB	687000	Kalk. AfA Anlagen	-	-	3,391.07	-	-	-
	Summe			605,178.20	531,333.00	584,166.18	515,921.11	644,029.98	960,706.70

Figure 85: Summary depreciation.

	Still Sonden			2006	2007	2008	2009	2010	2011
829900	Still Sonden	450300	Chem. Arbeitsstoffe	-	-	122.34	50.64	68.28	16.24
829900	Still Sonden	500100	Bau - Div Arbeiten	-	-	1,094.40	-	-	-
829900	Still Sonden	555000	Landw. Arbeiten	2,965.61	3,121.39	4,239.10	3,384.03	4,956.43	6,084.09
829900	Still Sonden	592000	Grundueberlassung	8,658.29	9,105.25	9,893.76	9,171.01	9,171.01	9,156.31
829900	Still Sonden	L250	LV FBZ	-	-	222.00	672.79	827.55	155.25
829900	Still Sonden	U328	Well Survey	-	-	15,692.99	-	-	-
	Summe			11,623.90	12,226.64	31,264.59	13,278.47	15,023.27	15,411.89

Figure 86: Summary inactive wells expenditure.

	Behandlung Wasser			2006	2007	2008	2009	2010	2011
829600	Behandlung Wasser	450000	Mech. Material	-	2,417.32	-2,095.97	-1.00	737.91	-
829600	Behandlung Wasser	450200	E/MSR-Material	-	-	206.92	-	-	-
829600	Behandlung Wasser	450300	Chem. Arbeitstoffe	-	1,585.11	2,057.64	-	-	-
829600	Behandlung Wasser	456000	Tubing	-	21,215.74	11,105.20	-6,747.99	2,903.68	2,923.69
829600	Behandlung Wasser	487000	Dieselöl	-	-	163.63	-	-	-
829600	Behandlung Wasser	500100	Bau - Div Arbeiten	-	4,866.10	681.80	2,254.17	-	-
829600	Behandlung Wasser	500200	Sonstige E-Arbeiten	-	-	229.90			
829600	Behandlung Wasser	508000	Sonst.Transporte	-	-	-	-	-	1,810.00
829600	Behandlung Wasser	520000	Messen	-	9,039.57	-	26,325.86	19,935.36	-
829600	Behandlung Wasser	550000	Proj-Vermessung	-	-	-	35.00	-	-
829600	Behandlung Wasser	565000	Entschaedigungen	-	-	35.00			
829600	Behandlung Wasser	638001	LV - SBH-Winde ZDF	-	104,440.00	54,680.00	82,200.00	22,010.00	19,220.00
829600	Behandlung Wasser	638009	SBH-Winde ZDF-man Bu	-	-1,938.30	-	-	-	-
829600	Behandlung Wasser	L250	LV FBZ	-	-	9,397.92	4,917.27	1,762.38	280.30
		Summe		0.00	137,623.11	76,293.45	108,984.31	46,611.42	24,233.99

Figure 87: Summary water treatment expenditure.

	Abwasser			2006	2007	2008	2009	2010	2011
829500	Abwasser	450000	Mech. Material	5,375.01	4,494.42	2,407.36	3,402.31	3,481.68	1,046.82
829500	Abwasser	450200	E/MSR-Material	-	681.29	3,429.13	925.78	1,161.44	7,369.80
829500	Abwasser	450300	Chem. Arbeitstoffe	7,278.60	14,136.98	11,519.13	12,525.87	11,468.72	5,767.88
829500	Abwasser	450400	K-Schutz/Arb-Stoffe	-	-	1,627.08	905.50	-	-
829500	Abwasser	471000	Bekleidung	-	-	-	123.19	-	-
829500	Abwasser	480000	Fremdstrom (Kauf)	98,845.78	122,204.23	128,077.12	157,847.80	160,037.45	132,775.24
829500	Abwasser	500100	Bau - Div Arbeiten	60,903.88	69,570.66	50,287.05	60,375.61	27,621.92	25,709.66
829500	Abwasser	500110	Überprüfungen	-	632.90	151.20	-	-	247.91
829500	Abwasser	500120	Kor.schutz,Erhaltung	-	-	-	1,478.41	-	-
829500	Abwasser	500200	Sonstige E-Arbeiten	195.07	1,775.12	9,460.77	967.66	3,910.13	3,041.07
829500	Abwasser	500210	E-Überprüfungen	-	-	-	912.32	794.60	883.65
829500	Abwasser	503100	Arb.mit Saugwagen	-	-	8,907.23	3,177.26	-	-
829500	Abwasser	508000	Sonst.Transporte	-	1,841.66	-	-	-	-
829500	Abwasser	555000	Landw. Arbeiten	-	6,714.89	3,767.21	3,441.80	5,439.42	5,586.66
829500	Abwasser	565000	Entschaedigungen	-	-	-	150.00	-	-
829500	Abwasser	579000	Sonst Leist,Kosten	40.00	-	-	76.10	-	-
829500	Abwasser	579100	Div.Aufw.aus Handkas	-	27.46	-	-	-	-
829500	Abwasser	592000	Grundueberlassung	-	-	35.20	-	-	-
829500	Abwasser	599100	Abfall - Entsorgung	2,191.04	-	-	3,199.92	2,662.20	-
829500	Abwasser	612010	V-Auftrag - Sanierun	-	16,340.21	259,332.85	-	38,943.78	-
829500	Abwasser	612030	V-Auftrag - Replacem	21,892.10	-	-	-	-	-
829500	Abwasser	L250	LV FBZ	-	-	20,701.01	21,729.47	32,029.31	15,233.00
		Summe		196,721.48	238,419.82	499,702.34	271,239.00	287,550.65	197,661.69

Figure 88: Summary residual water expenditure.

	Behandlung			2006	2007	2008	2009	2010	2011
829400	Behandlung	526100	Tubingreinigung	10,227.02	12,558.24	7,502.55	19,540.71	8,547.52	1,029.49
829400	Behandlung	526400	SBH Winde	34,015.80	13,031.44	2,904.50		-	5,200.00
829400	Behandlung	551000	Bewirtungen	-	493.06	-	-	-	-
829400	Behandlung	552000	Gutachten,Analysen	1,827.00	-	-	2,000.00	2,520.00	-
829400	Behandlung	553200	Geraetemieten Ausl	11,688.00	8,043.00	37,805.85	-	-	-
829400	Behandlung	553400	Sonstige Mieten	11,570.90	26,953.60	29,774.10	26,776.00	24,888.40	42,894.32
829400	Behandlung	612020	V-Auftrag - Optimier	23,593.99	-	-	-	-	-
829400	Behandlung	638001	LV - SBH-Winde ZDF	931,700.00	756,000.00	833,360.00	852,675.00	620,155.00	782,440.00
829400	Behandlung	638009	SBH-Winde ZDF-man Bu	-31,125.91	-13,990.00	23,776.87	6,134.08	61,695.37	-1,226.50
829400	Behandlung	679999	ILV-Umb/Saldenausgl	5,344.51	-3,465.35	3,004.31	-5,061.10	-	-
829400	Behandlung	820003	Erl.f.weiterb.Eigen-	-	-	-	-2,047.65	-	-
829400	Behandlung	L250	LV FBZ	110,312.61	113,503.51	110,265.81	138,644.05	118,048.62	148,082.75
		Summe		1,109,153.92	913,127.50	1,048,393.99	1,038,661.09	835,854.91	978,420.06

Figure 89: Summary treatment expenditure.

7.2 Appendix B

Year	Decline 4%, Price Variable, Expenditure Variable						
	Price 1%	Price 3%	Price 4%	Price 5%	Expenditur 2%	Expenditur 2.5%	Expenditur 3%
2012	10382176	10580312	10683034	10785755	6949100	6983164	7017228
2013	10073717	10461813	10665941	10872041	7088082	7157743	7227745
2014	9774489	10344641	10648876	10959018	7229843	7336686	7444577
2015	9484215	10228781	10631837	11046690	7374440	7520104	7667914
2016	9202626	10114218	10614826	11135063	7521929	7708106	7897952
2017	8929461	10000939	10597843	11224144	7672367	7900809	8134890
2018	8664466	9888929	10580886	11313937	7825815	8098329	8378937
2019	8407396	9778173	10563957	11404449	7982331	8300787	8630305
2020	8158012	9668657	10547054	11495684	8141978	8508307	8889214
2021	7916084	9560368	10530179	11587650	8304817	8721015	9155891
2022	7681387	9453292	10513331	11680351	8470914	8939040	9430568
2023	7453704	9347415	10496510	11773794	8640332	9162516	9713485
2024	7232824	9242724	10479715	11867984	8813139	9391579	10004889
2025	7018543	9139206	10462948	11962928	8989401	9626368	10305036
2026	6810662	9036846	10446207	12058631	9169189	9867028	10614187
2027	6608990	8935634	10429493	12155100	9352573	10113703	10932613
2028	6413339	8835555	10412806	12252341	9539625	10366546	11260591
2029	6223530	8736596	10396145	12350360	9730417	10625710	11598409
2030	6039386	8638747	10379511	12449163	9925025	10891352	11946361
2031	5860737	8541993	10362904	12548756	10123526	11163636	12304752
2032	5687419	8446322	10346324	12649146	10325996	11442727	12673894
2033	5519271	8351723	10329769	12750339	10532516	11728795	13054111
2034	5356139	8258184	10313242	12852342	10743167	12022015	13445734
2035	5197871	8165693	10296741	12955161	10958030	12322565	13849107
2036	5044323	8074237	10280266	13058802	11177191	12630630	14264580
2037	4895351	7983805	10263817	13163273	11400734	12946395	14692517
2038	4750819	7894387	10247395	13268579	11628749	13270055	15133293
2039	4610594	7805970	10230999	13374727	11861324	13601807	15587291
2040	4474547	7718543	10214630	13481725	12098551	13941852	16054910
2041	4342552	7632095	10198286	13589579	12340522	14290398	16536557
2042	4214487	7546616	10181969	13698296	12587332	14647658	17032654
2043	4090236	7462093	10165678	13807882	12839079	15013849	17543634
2044	3969683	7378518	10149413	13918345	13095860	15389196	18069943
2045	3852719	7295879	10133174	14029692	13357777	15773926	18612041

Figure 90: Results framework scenario A.

Year	Price 3%, Decline Variable., Expenditure Variable					
	Decline 3%	**Decline 4%**	**Decline 5%**	**Expenditure 2%**	**Expenditure 2.5%**	**Expenditure 3%**
2012	10690524	10580312	10470101	6949100	6983164	7017228
2013	10680903	10461813	10244994	7088082	7157743	7227745
2014	10671290	10344641	10024726	7229843	7336686	7444577
2015	10661686	10228781	9809195	7374440	7520104	7667914
2016	10652090	10114218	9598297	7521929	7708106	7897952
2017	10642503	10000939	9391934	7672367	7900809	8134890
2018	10632925	9888929	9190007	7825815	8098329	8378937
2019	10623355	9778173	8992422	7982331	8300787	8630305
2020	10613794	9668657	8799085	8141978	8508307	8889214
2021	10604242	9560368	8609905	8304817	8721015	9155891
2022	10594698	9453292	8424792	8470914	8939040	9430568
2023	10585163	9347415	8243659	8640332	9162516	9713485
2024	10575636	9242724	8066420	8813139	9391579	10004889
2025	10566118	9139206	7892992	8989401	9626368	10305036
2026	10556609	9036846	7723293	9169189	9867028	10614187
2027	10547108	8935634	7557242	9352573	10113703	10932613
2028	10537615	8835555	7394761	9539625	10366546	11260591
2029	10528131	8736596	7235774	9730417	10625710	11598409
2030	10518656	8638747	7080205	9925025	10891352	11946361
2031	10509189	8541993	6927980	10123526	11163636	12304752
2032	10499731	8446322	6779029	10325996	11442727	12673894
2033	10490281	8351723	6633279	10532516	11728795	13054111
2034	10480840	8258184	6490664	10743167	12022015	13445734
2035	10471407	8165693	6351115	10958030	12322565	13849107
2036	10461983	8074237	6214566	11177191	12630630	14264580
2037	10452567	7983805	6080953	11400734	12946395	14692517

Figure 91: Results framework scenario B.