Economic efficiency calculation of new technology employments in brown fields in Romania

Master thesis

by

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ppm	parts per million
NPV	net present value
bbl	barrel
diss.	dissertation
cf.	confer
p.	page
capex	capital expenditures
opex	operating expenditures
EMI	electromagnetic inspection
WTS	wall thickness measuring system
API	American Petroleum Institute
DC	direct current
VGA	Video Graphics Array
SRS	sucker rod string

1 Abstract

The oil and gas company OMV wants to introduce new technologies for wells in Romania to increase the annual production there. These new technologies should reduce the current annual intervention frequency and therefore lead to a higher annual production. This thesis deals with the estimation of the total savings and the production increase, which are caused by the employment of new technologies in Romania. These new technologies include the installation of new tubing material, the installation of new sucker rod strings and the employment of corrosion inhibitors. For every new planned action an employment scenario, which includes a best, a worst and a most realistic case, has been calculated. In addition an employment scenario for the combination of the most realistic cases has been evaluated. Afterwards a Monte Carlo Simulation has been carried out to consider how the variability of different input parameters affects various output parameters. The results of the simulation show that the oil price, the number of interventions and the intervention costs have a significant influence on the total savings. In comparison to these, the influences of the material costs are very low. The reason for this is that the savings due to the reduced number of interventions are significantly higher than the costs for the new technologies. This fact shows that enormous savings could be realized by the employment of the new technologies.

Der Öl- und Gaskonzern OMV beabsichtigt neue Technologien für Sonden in Rumänien einzuführen, um die jährliche Produktion zu erhöhen. Diese neuen Technologien sollen die aktuelle Behandlungsfrequenz reduzieren und somit zu einer höheren jährlichen Produktion führen. Diese Arbeit befasst sich mit der Schätzung der Ersparnisse und der Produktionserhöhung, die durch den Einsatz neuer Technologien in Rumänien verursacht werden. Diese Technologien umfassen die Installation neuer Steigrohre, die Installation neuer Pumpgestänge und den Einsatz von Korrosionsinhibitoren. Für jede geplante Maßnahme wurde ein Einsatzszenario, welches einen schlechtesten, besten und realistischsten Fall berücksichtigt, berechnet. Zusätzlich wurde noch ein Kombinations-Szenario der realistischsten Fälle errechnet. Danach wurde eine Monte Carlo Simulation durchgeführt, um den Einfluss verschiedener Inputparameter auf bestimmte Outputparameter zu untersuchen. Die Resultate der Simulation zeigen, dass der Ölpreis, die Anzahl der Behandlungen und die Behandlungskosten den größten Einfluss auf die Ersparnisse haben. Im Vergleich dazu sind die Einflüsse der Materialkosten sehr gering. Der Grund dafür ist, dass die Ersparnisse aufgrund der reduzierten Behandlungsanzahl bedeutend höher sind, als die Kosten für die neuen Technologien. Diese Tatsache zeigt, dass durch den Einsatz neuer Technologien enorme Ersparnisse erzielt werden können.

2 Introduction

The oil and gas company OMV has the intention to install new materials and to introduce new technologies for wells in Romania to increase the annual production there. The task of this thesis is to estimate the savings and the production increase, which could be realized due to employment of the new technologies.

2.1 Current situation in Romania

In 2004 OMV acquired 51% of the Romanian oil and gas company Petrom. At the moment 9,540 pumping wells are installed in Romania. These wells are characterized by a significantly high number of workovers per year. Generally a workover can be described as a major maintenance job on an oil or gas well.[1]

A workover in Romania cannot be compared to a usual workover in Austria, because in Austria a workover serves the purpose of preventive maintenance. In Romania the philosophy is just to wait until, for example, a tubing failure or a sucker rod string failure occurs. If such a failure happens an intervention is carried out to exchange just the broken tubing joint or sucker rod joint. Currently the average intervention frequency of a well in Romania is approximately 10 interventions per year.[2]

Compared to Austria less preventive maintenance is practiced in Romania, because just the broken parts are exchanged when doing an intervention. The average costs for an intervention in Romania are on average about 2,270 Euro. These costs have been calculated by evaluating the average intervention costs of eight operating regions in Romania. The average endurance of one intervention, without consideration of the dead time, which is the time the well 'waits' for the intervention, is 27 hours. This average endurance has been calculated by evaluating the average intervention endurances of the same eight operating regions in Romania again.

2.2 Comparison to the situation in Austria

In Austria, where preventive maintenance is carried out, the average time period between two workovers is about 1,200 days. In Austria the philosophy is not just to exchange the broken part instead 100% of the tubing material in the well are wall thickness surveyed, and additionally 10% of the tubing material is replaced with new material, which is J-55 steel during every workover. The sucker rod string is exchanged after every third failure respectively after 25 million alternations of load. That means that it is replaced after approximately eight years under the assumption

[1] According to statements of experts.

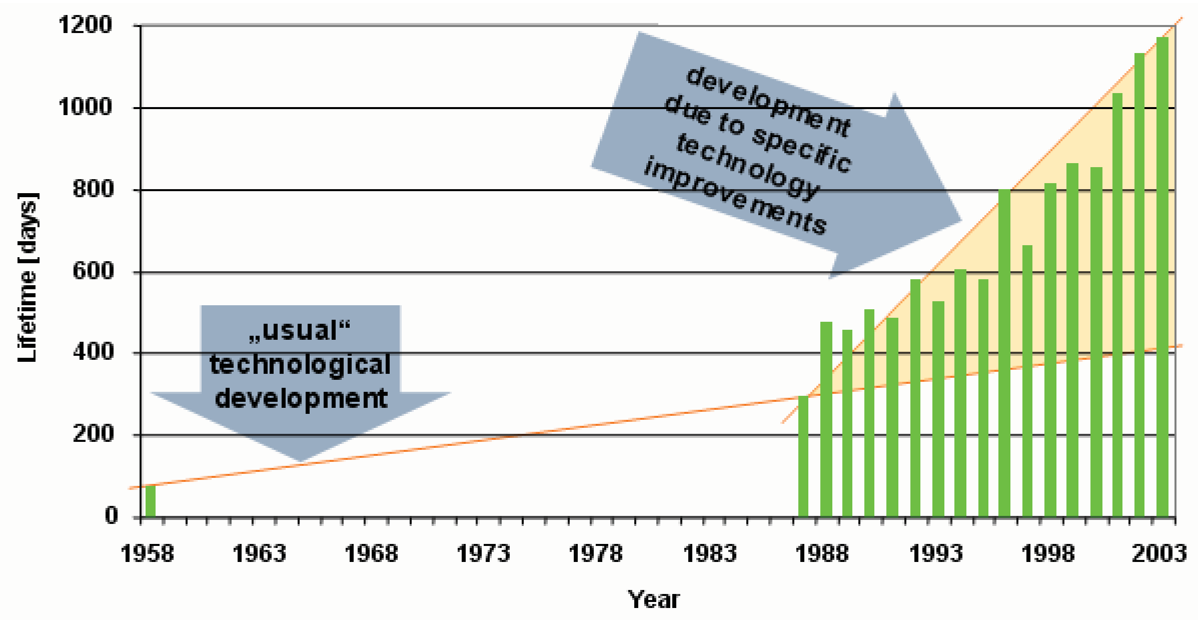
[2] According to statements of experts.

of 6 up- and down movements or strokes per minute. The cost for a workover in Austria is on average 30,000 Euro.[3]

In the 1980s the average workover frequency in Austria was also very high compared to the current situation. But the workover frequency could be decreased by the employment of new technologies. These technologies included the change of the tubing material, the rod grade and the rod guides as well as an inhibitor optimization.

Fig. 2-1 shows this development due to the employment of the new technologies. As can be observed in this table the lifetime of a sucker rod pumped unit could be increased from about 300 days in the year 1986 to about 1,200 days in the year 2003.

Fig. 2-1 Increase in Lifetime of Sucker Rod Pump Units[1]



2.3 Aim of the master thesis

OMV wants to decrease the intervention frequency in Romania by the employment of new materials and new techniques in brown fields in Romania. A brown field is an oil or gas accumulation that has progressed to a stage of declining production.[5] Furthermore it is characterized by an increasing water cut of a certain percentage per year. Currently this production decline is about 10% in Romania.[6] The goal of the planned actions, including new materials and new techniques, is now to decrease

[3] According to statements of experts.

[4] From Havlik,Oberndorfer (2006) p.6.

[5] www.glossary.oilfield.slb.com

[6] According to statements of experts.

this 10% decline in Romania by increasing the production time, which should be realized by a lower number of interventions per year. Obviously, less intervention time means more production time. Due to the decreased number of interventions per year – and the therefore increased annual production time – the annual production decline can be reduced. This reduction of the production decline causes an annual production increase.

The new material should include new tubings, new sucker rod strings and protectors for the sucker rod strings. The new techniques should cover the usage of corrosion inhibitors, thermoplastic tubular liners and the introduction of the wall thickness survey.

The aim of this thesis is to estimate the savings and the increase of production that can be realized by decreasing the intervention frequency. The decrease of the intervention frequency for every measure was assumed by experts from the OMV and is very conservative to guarantee a realistic model with realistic output parameters.

As already mentioned the decrease of intervention frequency for each measure was assumed and the task was to construct a calculation model. This model refers to 7,579 wells which are equipped with sucker rod pumps and covers a time period of 5 years. With this model it is possible to estimate the savings and the increase of production that can be realized by the assumed intervention frequency decrease for each planned action.

Afterwards a simulation with the software @risk® was carried out to consider how the variability of different input parameters affects various output parameters.

3 Description of the NPV method and the Monte Carlo Simulation

3.1 Description of the net present value method

The net present value method is used to calculate the profitability of a long term investment. It is a dynamic capital budgeting method. Two types of capital budgeting methods can be distinguished, the static methods and the dynamic methods. In comparison with the static methods, the dynamic methods observe several time periods and consequently the time value of the money is considered. [7]

That means that each net cash flow, which is defined as the difference between net annual revenues and net annual expenditures, of a long term investment has to be discounted at a certain discount factor to its present value. The net present value is then calculated as the sum of all these discounted cash flows of a long term investment.[8]

The exact definition of the net present value method is:

'The net present value method is a total analysis with the aim to calculate the present value of the cash flow (profit or cost savings), which flows back due to the amortization of the capital expenditure and the imputed interest rate'.[9]

The equation of the net present value can be represented as:[10]

$$NPV = \sum_{t=0}^{T} (e_t - a_t) * q^{-t}$$

$t = time\ index$

$T = last\ point\ of\ time\ in\ the\ calculation$

$e_t = revenues$

$a_t = expenditures$

$q = discounting\ factor$

Different net present value results have different impacts on planned long term investments. This fact is shown on Tab. 3-1.

[7] Cf. Warnecke, Bullinger, Hichert, Voegele (1996), p.30 et sq.
[8] Cf. Götze, Bloech (1995), p.73 et sqq.
[9] Warnecke, Bullinger, Hichert, Voegele (1996), p.90.
[10] From Götze, Bloech (1995), p.74.

Tab. 3-1 Interpretation of the result of the net present value calculation[11]

If NPV > 0	The invested capital is regained and the investment realizes a profit	The planned long-term investment should be realized
If NPV < 0	The invested capital is not regained and the investment incurs a loss	The planned long-term investment should be refused
If NPV = 0	The invested capital is regained and the investment neither realizes a profit nor a loss	The planned long-term investment should be refused, because no profit is realized

Choosing the right imputed interest rate is very important for the calculation. The imputed interest rate considers the opportunity costs, which develop because certain alternative chances or opportunities of the company are not taken. These opportunity costs can be described as the average earnings of other investments of the company, which are refused if the calculated long term investment is chosen.[12] Companies often have one single imputed interest rate with which they calculate the profitability of certain projects. For example the imputed interest rate of OMV is 11%.[13]

A simple example should illustrate the principle of discounting: If the interest rate for $1 is 15%, this dollar would grow to $1.15 after one year. That means that $1/1.15 or 0.8696$ would grow to $1 after one year assuming an interest rate of 15%. Thus the present value of $1, which is received in one year is $0.8696 assuming an imputed interest rate of 15% or conversely the discounted value of $1 at a imputed interest rate of 15% would be $0.8696. This procedure is shown for a time period of ten years on Tab. 3-2, which be found on the next page.[14]

[11] Cf. Warnecke, Bullinger, Hichert, Voegele (1996), p.90 et sq.
[12] Cf. Götze, Bloech (1995), p.86.
[13] According to statements of experts.
[14] Cf. Allen, Seba (1993), p. 157 et sq.

Tab. 3-2 Development of a sum of $1 at an interest rate(1) and an imputed interest rate (2) of 15%[15]

Year	(1)	(2)
0	$1.0000	$1.0000
1	$1.1500	$0.8696
2	$1.3225	$0.7561
3	$1.5209	$0.6575
4	$1.7409	$0.5718
5	$2.0114	$0.4972
6	$2.3131	$0.4323
7	$2.6600	$0.3759
8	$3.0590	$0.3269
9	$3.5179	$0.2843
10	$4.0456	$0.2472

The value of $1 has doubled after approximately 5 years. That coincides with the rule of 72 which states that the time needed to double the money at a certain interest rate can be calculated by dividing 72 by the interest rate, which would be 72/15, and that equals 4.8.[16]

3.2 Description of the payout period

The payout period of an investment is the time from the first expenditure of a long term investment until the net present value becomes positive or, in other words, it is the time period which is necessary to regain the invested capital from the sum of the net cash flows.[17]

[15] From Allen, Seba (1993), p. 158.
[16] Cf. Allen, Seba (1993), p. 158.
[17] Cf. Allen, Seba (1993), p. 149.

The following formula is used to calculate the payout period of an investment:[18]

$$Payout\ period = t + KW_t / (KW_t - KW_{t+1})$$

$t = last\ period\ which\ shows\ a\ negative\ net\ present\ value$

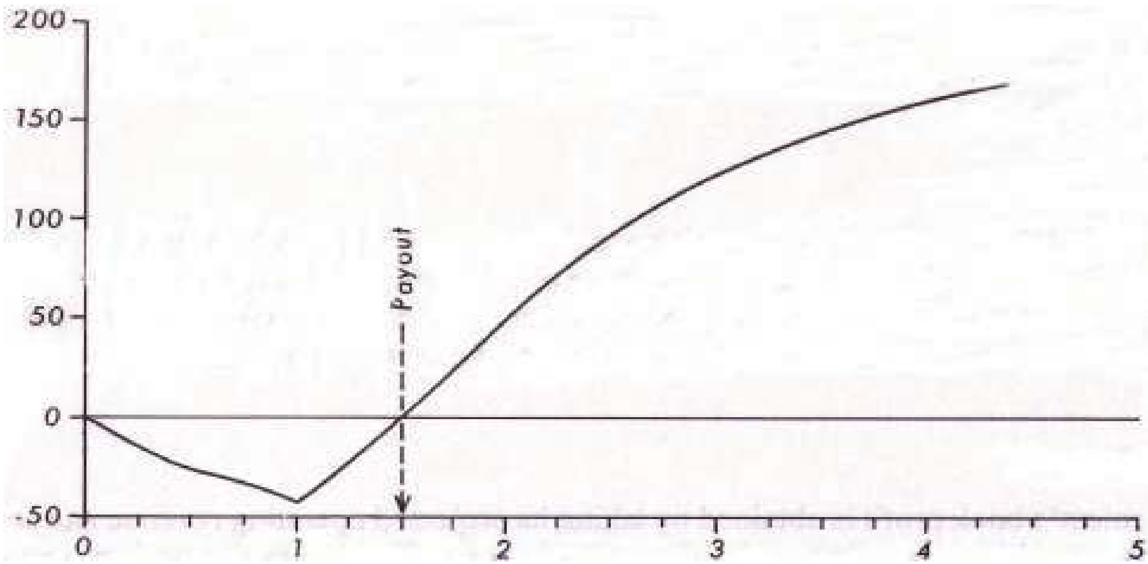
$KW_t = net\ present\ value\ of\ the\ last\ period\ which\ shows\ a\ negative\ net\ present\ value$

$KW_{t+1} = net\ present\ value\ of\ the\ first\ period\ which\ shows\ a\ positive\ net\ present\ value$

Fig. 3-1 shows the payout period of a long-term investment. The chart shows that the payout period for this investment equals to 1.5 years or 18 months.

Fig. 3-1 Payout period of a long-term investment[19]

NPV [Thousands of Dollars]



Time [years]

[18] From Götze, Bloech (1995), p.103.

[19] From Allen, Seba (1993), p. 149.

3.3 Monte Carlo Simulation

Generally a simulation is an analytical method, which tries to imitate a real life system. The Monte Carlo Simulation is a numerical method, which is used to simulate the behavior of physical, mathematical or other kinds of systems. These systems have to be described by a stochastic model, which is then simulated.[20]

3.3.1 History of the Monte Carlo Simulation

The first documented use of random samplings in history was carried out by the Compte de Buffon. He did his experiment in 1777. For the execution of his experiment he took a horizontal plane and constructed straight lines with a distance of d on it. Then he calculated the probability that a needle with the length L $(L < d)$ will intersect one of these lines. The experiment was repeated many times. The mathematical analyses of this problem showed that the probability is $p = 2 * L/(\pi * d)$. Years after this experiment, Laplace had the idea that this experiment could be used for the evaluation of *PI*.[21]

The Monte Carlo method was also used in the Second World War for the construction of the atomic bomb. The first charts of random numbers were set up on the basis of roulette game results from the famous casino of Monaco. This was also the reason why the American scientists Metropolis and Ulam called this method of random sampling Monte Carlo Simulation in the year 1949. Today the Monte Carlo Simulation has many applications in different sciences like physics, mathematics and mathematical economics.[22]

3.3.2 Monte Carlo Simulation with the software @risk®

The software package @risk® is an add-in for Microsoft Excel®. First, a calculation model is created with an Excel® spreadsheet. This model contains a certain number of uncertain variables. These variables are the input parameters of the simulation. For each of these input parameters a probability distribution is defined. Two types of probability distributions can be distinguished: discrete distributions and continuous distributions. Examples for the discrete distributions are the Binomial-, the Discrete- and the Poisson Distribution. Examples for the continuous distributions are the Histogram, the Lognormal-, the Normal-, the Uniform and the Triangle Distribution.[23]

For the simulation of the calculation model of this thesis, the Triangle Distribution was used. The Triangle Distribution is indicated by the fact that the probability, which is shown on the ordinate, is decreasing from the centre to the lower and

[20] Cf. Hengartner, Theodorescu (1978), p.11
[21] Cf. Kalos, Whitlock (1986), p.4 et sq.
[22] Cf. Hengartner, Theodorescu (1978), p.17.
[23] Cf. Staber (2006), p.8.

upper boundaries of the abscissa. That means that the value in the middle of the probability distribution has the highest probability of being realized. For each input parameter a certain interval of possible values is defined. Concerning the thusly created calculation model, the probabilities of the input parameters to reach a value in the centre of the defined interval are higher than the probabilities that the input parameters lie at the upper or lower end of the assumed interval. For example, the defined interval for the oil price is between $20 and $100. The probability of the oil price to reach a value of $60 is much higher than to be $20 or $100. For this reason the Triangle Distribution has been chosen to represent the probability distribution of the defined input parameters.

Fig. 3-2 shows the density function of a Triangle distribution and Fig. 3-3 shows the distributive function of a Triangle Distribution. In comparison with the density function, the distributive function shows the accumulation of the probabilities.

Fig. 3-2 Density function of a Triangle distribution[24]

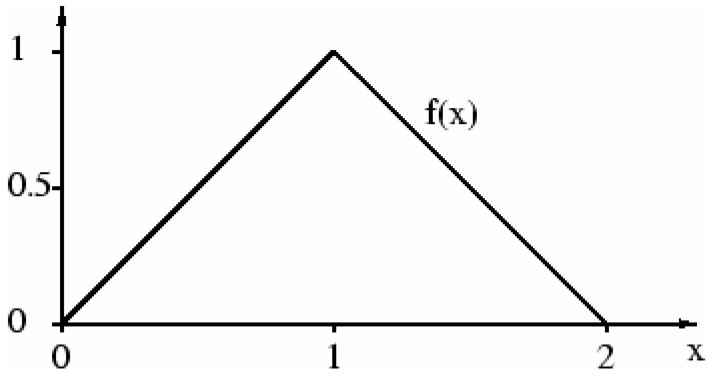
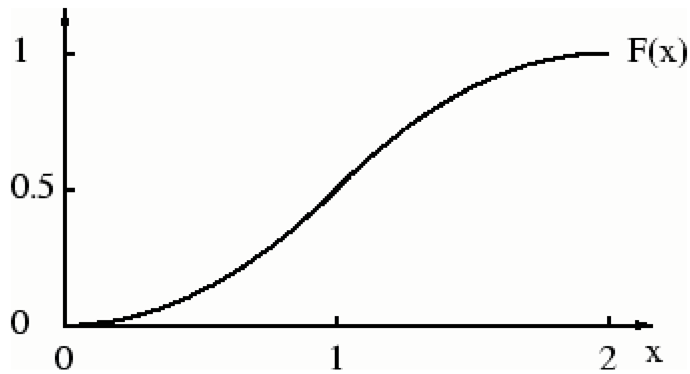


Fig. 3-3 Distributive function of a Triangle distribution[25]

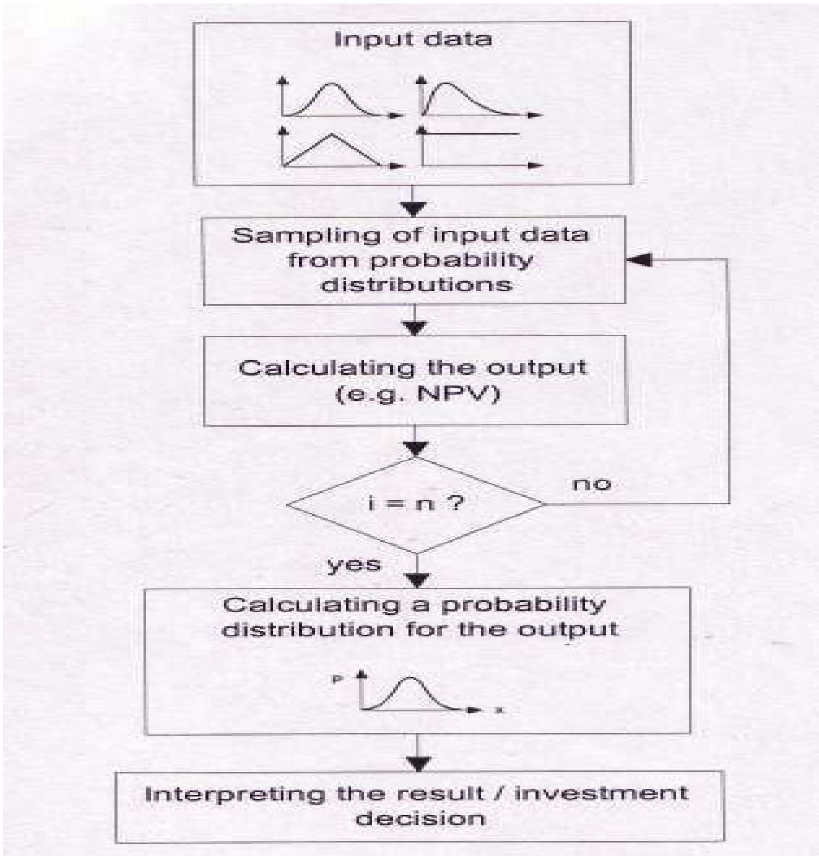


[24] www.statistik.tuwien.ac.at
[25] www.statistik.tuwien.ac.at

Besides the definition of input parameters, output parameters are also defined. These output parameters are usually the final results of the calculation model (e.g. NPV). Afterwards certain simulation settings have to be chosen. The most important of these settings are the number of simulation trials or iterations that are calculated during the simulation and the method of generating the random numbers. The software @risk® offers two methods to generate the random numbers, the Monte Carlo method and the Latin Hypercube method. For the simulation of the calculation model of this thesis the Monte Carlo method was used. After selecting the appropriate settings the simulation can be started. During one single simulation trial a random number from the defined probability distribution is created for each uncertain variable by the software @risk®. From these random numbers an output for each single simulation trial is calculated. The final result of these calculations is a probability distribution for each output.

After the simulation, the analysis of the simulation results, which can be displayed in Histograms and Tornado Charts, is carried out. For the interpretation of the Histograms certain measured values are used, which are the mean, the median and the mode. The mode is the most likely value, the median is the mid-value and the mean is the weighted average value. The whole flow chart of a Monte Carlo Simulation is shown on Fig. 3-4.

Fig. 3-4 Flow chart of a Monte Carlo Simulation[26]



[26] From Zettl (2000), p.43.

The flow chart shows that at first a probability distribution is defined for each of the input parameters. The next step of the Monte Carlo Simulation is the sampling of the input data from the defined probability distribution. After that a certain output parameter is calculated. As can be observed on the flow chart this procedure is repeated until the before defined number of iterations is reached. At the end of the Monte Carlo Simulation the software calculates a probability distribution for the output. Afterwards the results of the simulation are interpreted and investment decisions can be made.

3.3.3 Sensitivity analysis

The aim of a sensitivity analysis is to indicate how strong the influence of an input parameter on an output parameter is. Two types of sensitivity analyses can be distinguished: The probabilistic sensitivity analysis and the deterministic sensitivity analysis.

The following difference exists between these two analyses. The probabilistic analysis is used to compare the influences of all input parameters on a certain output parameter after a Monte Carlo Simulation was carried out. The deterministic analysis is used to show the influence of a single input parameter on a certain output parameter.

The first necessary step for doing a probabilistic analysis is to define a realistic probability distribution for all of the input parameters and to define the output parameters which are influenced by the uncertain variables. During the simulation run the input parameters are then varied between the previously defined boundaries: for example an oil price of $60 could be varied between $20 and $100. These boundaries can be defined as absolute values or as percentage rates of the basic initial value.

After the simulation, the strength of the influences of the different parameters is shown by using a Tornado Chart. The software @risk® creates a Tornado chart by means of a **regression analysis** or a **correlation analysis**.

Describing how a dependant variable Y relates to an independent variable X by a straight line is called the **regression** of Y on X. For the description of the linear regression a certain relation between a dependent variable Y and an independent variable X has been assumed. This relation ship is shown on Tab. 3-3.[27]

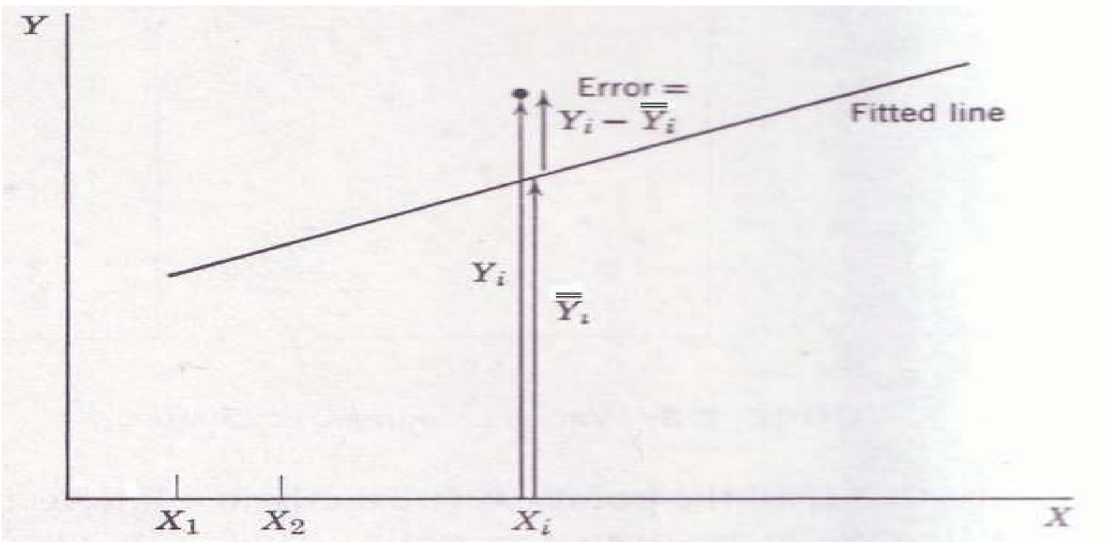
[27] Cf. Wonnacott, Wonnacott (1981), p. 13.

Tab. 3-3 Assumed relation between *X* and *Y*[28]

X	***Y***
100	40
200	50
300	50
400	70
500	65
600	65
700	80

The principle of linear regression is to determine a line, which fits these points in the best way. An accurate fit of these points minimizes the total error. A typical error, which is also called deviation, is displayed on Fig. 3-5.[29]

Fig. 3-5 Typical error in fitting points with a line[30]



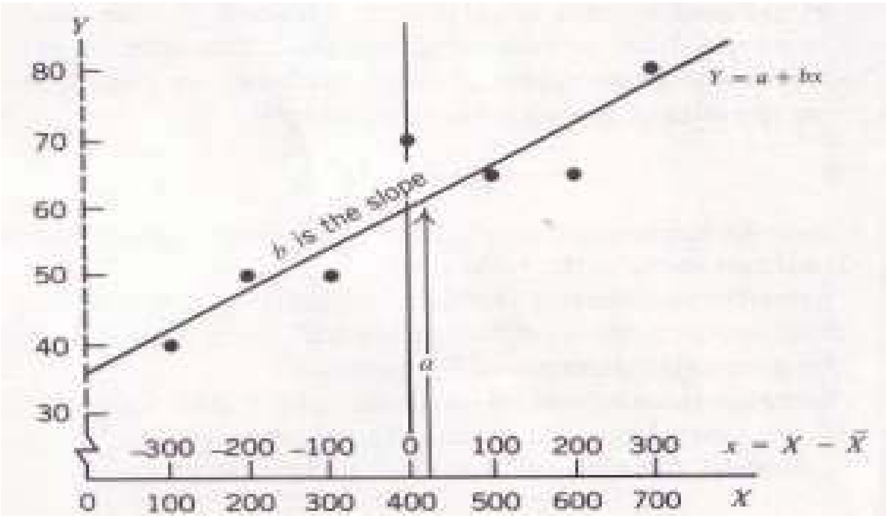
It is the vertical distance between Y_i and the value $\overline{\overline{Y}}_i$ on the fitted line. That means the vertical distance equals $Y_i - \overline{\overline{Y}}_i$. This error is negative when Y_i is below the fitted

[28] From Wonnacott, Wonnacott (1981), p. 14.
[29] Cf. Wonnacott, Wonnacott (1981), p. 15 et sq.
[30] From Wonnacott, Wonnacott (1981), p. 16.

line and positive when Y_i is above the fitted line. To minimize the total error the sums of the squares of the errors $\sum\left(Y_i - \overline{\overline{Y}}_i\right)^2$ are minimized:[31]

This solution is called the least squares solution. Fig. 3-6 shows again the Y values from Tab. 3-3 plotted against the X values from Tab. 3-3.

Fig. 3-6 Regression after translating X and Y[32]



As already mentioned the objective of the linear regression is to determine a line, which fits these points in the best way. For this purpose a new variable is defined at first. This new variable is called x and it equals $X - \overline{X}$, where $\overline{X}$ is the mean value of the X values. This new definition is equivalent to a geometric translation of the axes. This fact is also displayed on Fig. 3-5. The ordinate has been shifted right from 0 to $\overline{X}$. In this certain case $\overline{X}$ equals 400. The new x values are negative or positive. It depends on whether the X values are less or greater than $\overline{X}$. There is no change in the Y values. The sum of the new x values equals zero. The line that fits the assumed points in the best way is represented by the equation $Y = a + b * x$. The regression coefficients a and b must be selected in a manner that satisfies the least squares criterion. That means that the values of a and b are selected in a way that the term $\sum\left(Y_i - \overline{\overline{Y}}_i\right)^2$ is minimized. Each fitted value $\overline{\overline{Y}}_i$ is on the estimated line $\overline{\overline{Y}}_i = a + b * x$. Therefore $S(a,b) = \sum\left(Y_i - a - b * x_i\right)^2$, where the notation $S(a,b)$ depends on a and b. The question is now at which values of a and b $S(a,b)$ will be a minimum. This values are $a = \overline{Y}$, which is the mean value of the Y values, and $b = \left(\sum x_i * Y_i\right) / \sum x_i^2$. Concerning the example of Tab. 3-3 $a = 60$ and $b = 0.59$. That means that the least squares equation in this case equals $\overline{\overline{Y}}_i = 60 + 0.59 * x$.[33]

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[31] Cf. Wonnacott, Wonnacott (1981), p. 15 et sqq.

[32] From Wonnacott, Wonnacott (1981), p. 18.

[33] Cf. Wonnacott, Wonnacott (1981), p. 19 et sqq.

The regression analysis shows how certain variables are linearly related. In comparison to the regression analysis, the **correlation analysis** shows only the degree to which variables are linearly related. As already explained, in regression analysis a whole function is calculated. But in the correlation analysis only one number, which is the correlation coefficient *r*, is determined. This number is an index that shows how closely two variables move together. As it has been done for the regression analysis, a certain relation between an independent variable X and a dependent variable Y has been assumed, which is shown on Tab. 3-4.[34]

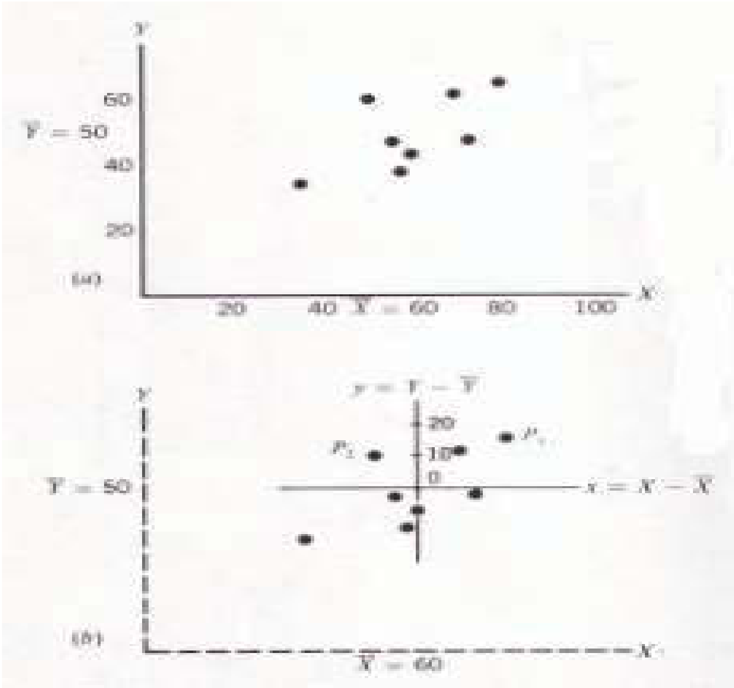
Tab. 3-4 Assumed relation between *X* and *Y*[35]

X	***Y***
36	35
80	65
50	60
58	39
72	48
60	44
56	48
68	61

Fig. 3-7 displays two plots of these points. In Fig. 3-7 (b) both axes are shifted. Due to this procedure two new variables are defined. These new variables are x, which equals $X-\overline{X}$ and y, which is $Y-\overline{Y}$. In this certain case the mean value $\overline{X}$ equals 50 and the mean value $\overline{Y}$ is 60.[36]

[34] Cf. Wonnacott, Wonnacott (1981), p. 152.
[35] From Wonnacott, Wonnacott (1981), p. 153.
[36] Cf. Wonnacott, Wonnacott (1981), p. 152. et sqq.

Fig. 3-7 Plot of assumed points[37]



If the x and y values of a certain point have the same sign, the point will be in the first or in the third quadrant, such as P_1. Conversely if the x and y values of a certain point have the same sign, the point will be in the first or in the third quadrant, such as P_1. For this reason, if X and Y are related positively, that means one rises when the other rises, most of the points will be in the first and third quadrant. But if X and Y are related negatively, that means one rises when the other falls, most of the points will be in the second and fourth quadrant. If there is no relation between X and Y the points are evenly distributed over the four quadrants.[38]

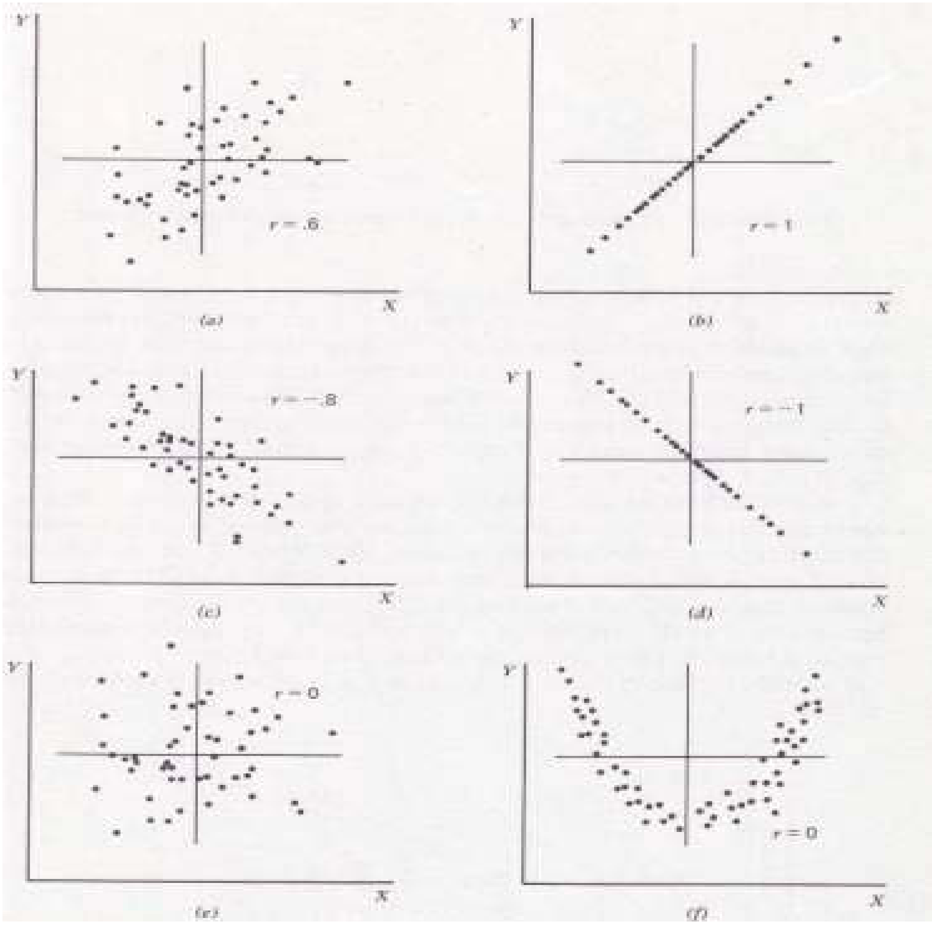
The correlation coefficient is calculated by using the following formula:[39]

$$r = \sum(x * y) / \sqrt{\left(\sum x^2 * \sum y^2\right)}$$

[37] From Wonnacott, Wonnacott (1981), p. 154.
[38] Cf. Wonnacott, Wonnacott (1981), p. 155.
[39] Cf. Wonnacott, Wonnacott (1981), p. 156.

Fig. 3-8 shows different relations between X and Y.

Fig. 3-8 Different relations between *X* and *Y*[40]



In Fig. 3-8(b) X and Y have a perfect positive relation, and so the correlation coefficient r equals 1. Fig. 3-8(d) displays a perfect negative relation. In this case the correlation coefficient r is 1. Consequently the correlation coefficient r has an upper limit of 1 and a lower limit of -1.[41] If an input parameter and an output parameter have a high correlation coefficient, it means that the input variable has a significantly high impact on the output parameter. Negative coefficients indicate that an increase in the input parameter is associated with a decrease in the output parameter. Positive coefficients indicate that an increase in the input parameter leads to an increase in the output parameter.[42]

The correlation coefficients of Fig. 3-8(e) and Fig. 3-8(f) are 0. Fig. 3-8(e) shows no relation between X and Y, but Fig. 3-8(f) shows a strong relation between X and Y. Therefore a zero value of the correlation coefficient r does not mean that there

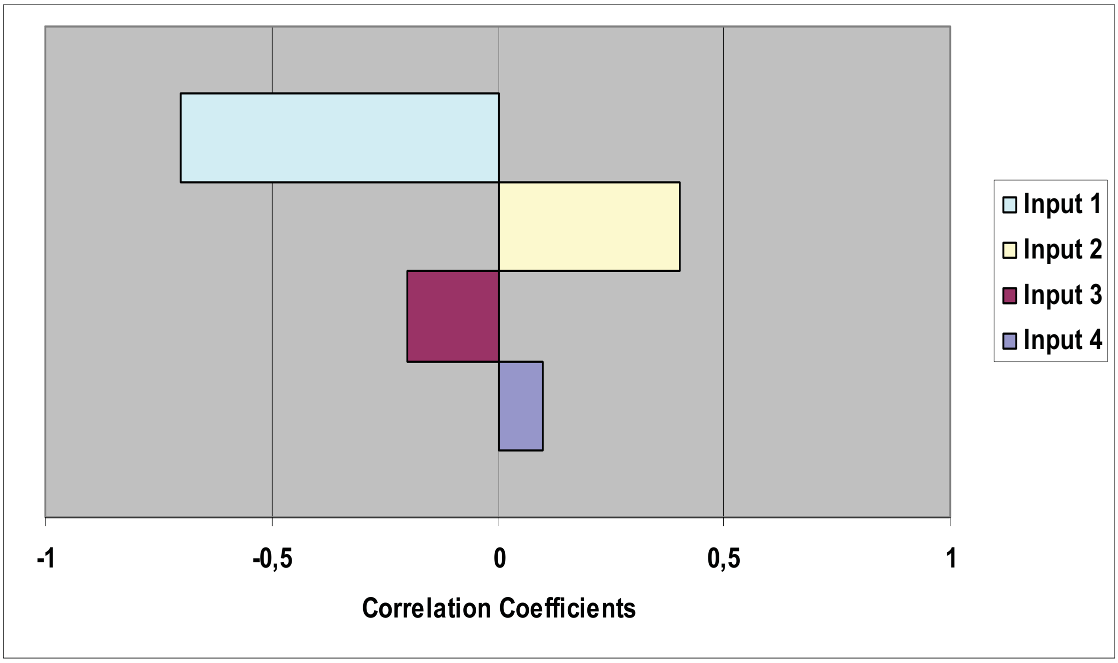
[40] From Wonnacott, Wonnacott (1981), p. 157.
[41] Cf. Wonnacott, Wonnacott (1981), p. 156.
[42] www.decisiioneering.com

is no relation between X and Y, it just means that there is no *linear* relation between X and Y. Thus this form of correlation is just a measure of *linear* relation.[43]

This procedure leads to a measurement of sensitivity for each input variable. A Tornado Chart consists of horizontal bars which are arranged one after another according to size. The longer a bar of a certain input parameter is, the higher is its influence on the output parameter. That means that the longer bars at the top of the diagram represent the most significant input parameters.[44] The abscissa of a Tornado chart displays the correlation coefficient which, as already explained, ranges between -1 and 1. Another important aspect of the Tornado charts is the side of the input parameters. If the output parameter increases with an increasing value of the input variable, the input parameter is displayed on the right side of the diagram. But if the output parameter decreases with an increasing value of the input variable, the input parameter is displayed on the left side of the diagram.

Fig. 3-9 shows an example of a Tornado Chart which shows the influence of four different input variables. As can be seen from the chart, Input 1 has the highest influence on the output and Input 4 has the lowest influence.

Fig. 3-9 Example of a Tornado Chart



As already mentioned, deterministic analyses are carried out to show the influence of a single input parameter on a certain output parameter. For these analyses no simulation is necessary. Instead of this every single input parameter is changed in fractional steps to show how strong the influence of the parameter is. Afterwards, the change of the output parameter with the input parameter is plotted. By plotting

[43] Cf. Wonnacott, Wonnacott (1981), p. 156.

[44] Cf. Guide to using @risk® (2002), p.66.

a coordinate for every single input parameter in one diagram a Spider Diagram is created. The steeper a graph in this diameter is, the stronger the output is influenced by the respective input parameter. So when analyzing a spider diagram the focus should be laid on the high slope input parameters.[45]

Fig. 3-10 Example of a Spider Diagram[46]

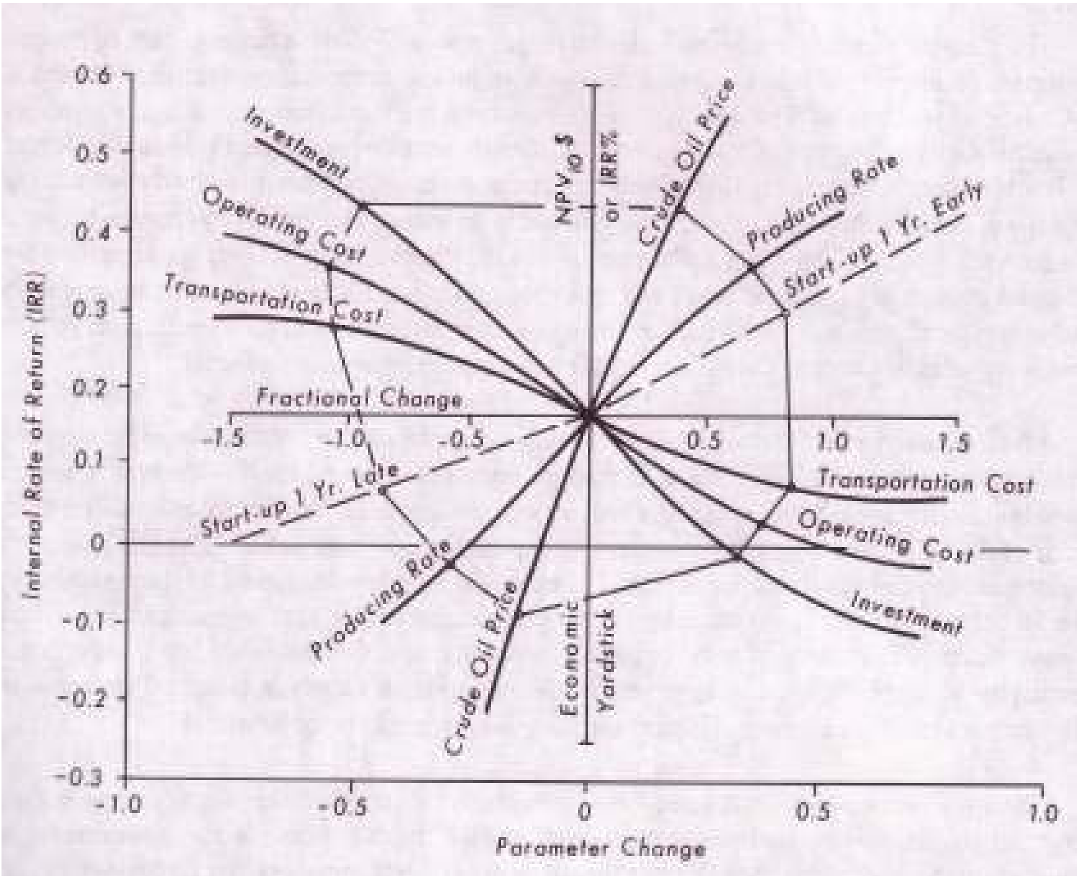


Fig. 3-10 represents a Spider Diagram. The abscissa shows the fractional changes of the input parameters and the ordinate represents the resulting change of the output parameter. The most important input parameters in this diagram are for example the crude oil price and the production rate. The output parameter in this diagram is the Internal Rate of Return, which can be described as the discount factor at which the net present value of an investment is zero. In other words if the discount factor is increased, the net present value decreases and at a certain discount factor, which is the internal rate of return, it becomes zero. All curves of the diagram go through the origin, because if the input parameters are not varied, the output parameter will not change either. By connecting the limits between which the input parameters are varied, the spider web can be constructed, which can also be seen on Fig. 3-10.

[45] Cf. Allen, Seba (1993), p. 214 et sq.

[46] From Allen, Seba (1993), p. 214.

4 Description of sucker rod pumping and new technologies

This chapter gives the reader an overview about the design and the operating mode of a sucker rod pumping unit. Furthermore it describes the new technologies, which are planned to be employed at wells in Romania.

4.1 Sucker rod pumping

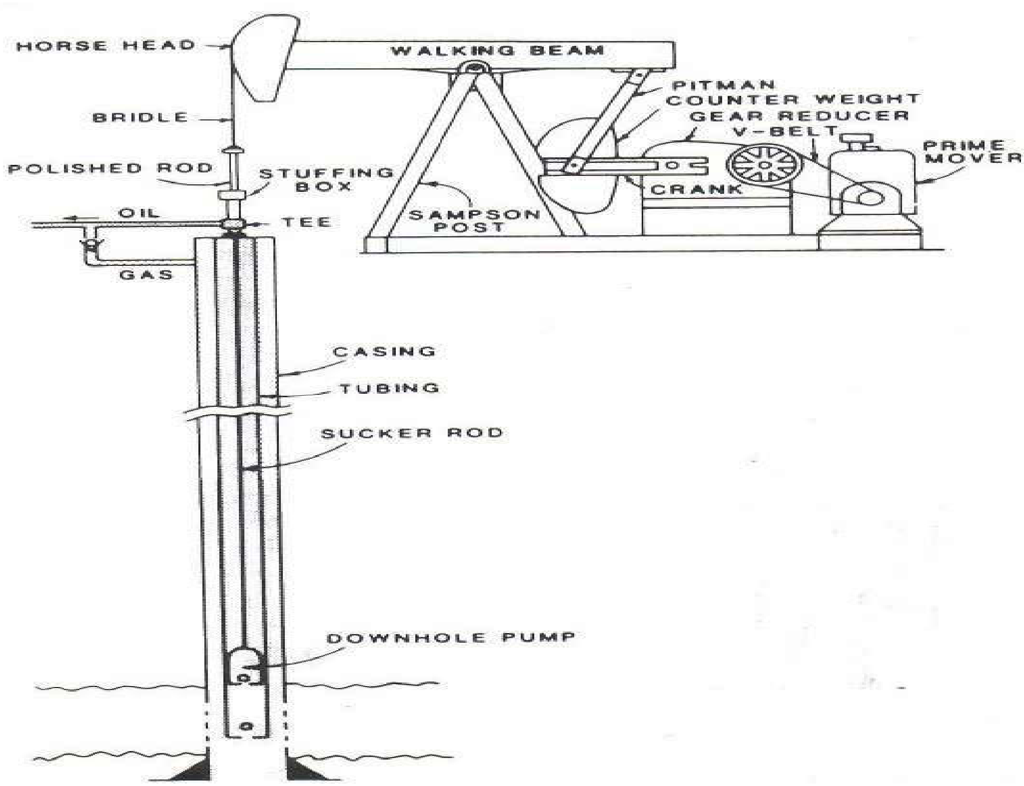
Sucker rod pumps are downhole pumps which are used to lift reservoir fluids to the surface. They increase the productivity of the well by reducing the pressure at the bottom of the well, the so-called bottomhole flowing pressure. The pumps act by increasing the pressure at the bottom of the tubing to lift the production medium to the surface. Two types of pumps are used, which are the positive displacement pumps and the dynamic displacement pumps. Sucker rod pumps belong to the group of positive displacement pumps.[47]

4.1.1 Components of a sucker rod pump unit

The main components of a sucker rod pumping unit are the prime mover, the V-Belt, the gear reducer, the crank with the attached counterweight, the pitman, the walking beam, the horse head, the Sampson post, the bridle, the polished rod, the stuffing box, the casing, the tubing, the sucker rod string and the downhole pump. Fig. 4-1 shows a well equipped with a sucker rod pump unit.[48]

[47] Cf. Economides/Hill/Ehlig-Economides (1994), p.551 et sqq.
[48] Cf. Economides/Hill/Ehlig-Economides (1994), p.553 et sq.

Fig. 4-1 Sucker rod pumped well[49]



The drive unit of a sucker rod pumping unit consists of three components. The first component is the prime mover which supplies power to the pumping unit system. The prime mover can be an electrical motor, a diesel engine or an internal combustion gas engine. The second part is the V-belt which is a transmission unit between the prime mover and the gear reducer. The gear reducer is the third component of the drive unit. The gear reducer reduces the high speed of the motor to the lower operating speed of the pumping unit. The crank translates this rotating motion into a reciprocating motion of the polished rod. The translation is fulfilled by the pitman and walking beam with the attached horse head as shown in Fig. 4-1. The crank arms with the attached counterweights even out the load on the drive unit. They do this by absorbing the energy during a downward stroke and releasing the energy during an upward stroke. The polished rod is on the upper side connected to the horse head by the so-called bridle. The polished rod has a polished surface and is connected on the lower side to the sucker rods below the stuffing box. The stuffing box contains packing elements. These elements form a seal with the polished rod. This prevents oil from spilling out of the top of the well. The Sampson post is a support for the walking beam. The subsurface equipment consists of the casing outside, the tubing, the sucker rod string inside the tubing and the downhole pump. The space between the casing and the tubing is called the annulus.[50]

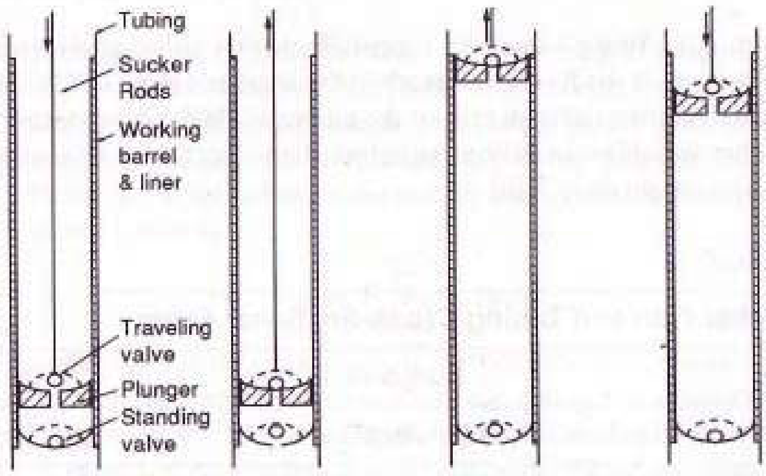
[49] From Economides/Hill/Ehlig-Economides (1994), p.554.

[50] Cf. Kessler (2003) p.112 et sqq.

4.1.2 Pumping process

A downhole pump consists of two parts, a barrel and a plunger. Sucker rod pumps have the same mode of function like piston pumps.[51] The barrel has a ball-and-seat check valve at its bottom. This valve is called standing valve. The plunger contains another ball-and-seat check valve, the traveling valve.[52] Fig. 4-2 shows the sequence of a pumping process carried out by a sucker rod pump.

Fig. 4-2 Pumping process of a sucker rod pump[53]



The pumping process starts with a downward movement of the plunger. During this downward movement the traveling valve opens, the standing valve closes and the production medium is displaced and pushed up into the tubing. While the plunger moves downward, the total fluid load must be borne by the production tubing. At the beginning of an upward movement the traveling valve closes. From this moment on the whole fluid load is put on the sucker rod string. At the same time the standing valve opens. During the upward movement of the plunger, the barrel is filled again with fluid, until the plunger is in the top dead end position again. This is followed by the downward movement of the plunger and the whole procedure starts again.[54]

4.1.3 Different types of sucker rod pumps

Generally three types of sucker rod pumps can be distinguished: Tubing pumps, insert pumps and casing pumps.

Concerning tubing pumps the pump cylinder or barrel is an integrated component of the production tubing-string. As a consequence the tubing pump must be installed at the same time as the rest of the tubing. Compared to an insert pump of the same tubing size, the production rate of a tubing pump is larger. Therefore the

[51] Cf. Kessler (2003) p.110.
[52] Cf. Economides/Hill/Ehlig-Economides (1994), p.553.
[53] From Economides/Hill/Ehlig-Economides (1994), p.555.
[54] Cf. Kessler (2003) p.110.

production rate is higher than that of the tubing pump. These pumps are used for medium production rates.[55]

Insert pumps are inserted into the sucker rod string. Two types of insert pumps can be distinguished. One type has a fixed cylinder, this type is the so-called stationary barrel insert pump and the other type has a moving cylinder and is the so-called traveling barrel insert pump.[56] Casing pumps are not used in OMV operated fields in Romania.[57]

4.2 Corrosion inhibitor

Generally **corrosion** is an electrochemical reaction of a metal or an alloy with its environment, which causes a deterioration of the material and destroys the structure of the metal or alloy.[58] The corrosion is measured in millimeter per year or milli-inch per year. 1 milli-inch conforms to 0.0254 millimeter. The threshold value or limit for corrosion is at 0.05 millimeter per year or 2 milli-inches per year.

A corrosion inhibitor is a chemical compound, which is added to a fluid system in rather small concentration to prevent or slow down the corrosion of a material, which is in contact with the fluid system. Inhibitors are widely used in production oil and gas wells. Corrosion inhibitors are used during the production to control the effect of the corrosion of steel and salt water, oil or hydrogen sulfide.[59]

In most cases, corrosion inhibitors are the most economic and most reliable way of corrosion control. The inhibitor concentration in which it is supposed to be added in Romania is approximately 35 ppm.[60]

In wells that are rod pumped the abrasion of the rods on the tubing also requires lubricating properties of the inhibitor film. It is also possible that air enters through the annulus of a well, and so the inhibitor must not lose its function in the presence of oxygen.[61]

Corrosion occurs almost anywhere in the production system, such as for example in downhole installations, in the surface lines and in the surface equipment. The rate of corrosion varies with time, depending on the particular conditions of the oilfield and pressure variations.[62]

The following procedure is carried out to inhibit the corrosion of a well: The inhibitor is injected by inhibitor treatment pumps into the annulus. Then it moves down to the pump, because of the higher specific gravity than the production medium and afterwards it is reproduced again through the tubing.

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[55] Cf. Kessler (2003) p.110 et sq.
[56] Cf. Kessler (2003) p.111 et sq.
[57] According to statements of experts.
[58] Cf. www.corrosionsource.com
[59] Cf. www.glossary.oilfield.slb.com
[60] According to statements of experts.
[61] Cf. Clubley (1990), p.23.
[62] Cf. www.glossary.oilfield.slb.com

OMV intends to equip a certain number of wells with inhibitor treatment pumps to inhibit these wells. The planned employment of the corrosion inhibitor is described in detail in chapter 5.

4.3 Thermoplastic tubular liners

For oil production wells which are equipped with beam pumps, thermoplastic tubular liners provide a long term protection on the inner diameter surface of the tubing. This is necessary to prevent wear which can be caused by either reciprocating or rotating rod action. The tubing failure is often the result of a synergistic effect of *two* processes: The *first* one is caused by the rods which are wearing along the tubing wall. This constant wear removes the protective passive film which was built on the tubing surface. This process is coupled with a *second* one which is the electrochemical attack of the surrounding environment, also known as corrosion.[63]

As wear is the main reason for tubing failure drastic reductions in operation costs can be achieved firstly by eliminating the wear which is caused by the rods on the inner surface of the tubing and secondly by reducing corrosion of the inner surface of the tubing. As will be explained in great detail in this thesis, the savings are being realized in the form of increased tubing life, less interventions, increased production, higher revenues and therefore higher profits for the following years.

There is also the possibility to apply the liners in used tubings, because it requires only minimal preparation. The benefits are realized even in highly deviated and doglegged wells. Thermoplastic tubular liners are nearly abrasion resistant and inert to chemicals, which are used to eliminate problems, which were caused by wireline damage, chemical treatments and acidizing.[64]

The **lining procedure** is carried out in the following manner. At first the thermoplastic tubular liner has to be sized for the various dimensional tolerances, so that it can be installed in the carbon steel tubulars. For that purpose, after manufacturing, it is reduced to the inner diameter of the API steel tubulars, which are already threaded and coupled. If there is no accumulation of scale or paraffin on the internal surface caused during previous services, no blasting or cleaning service of the tubing inner surface has to be carried out. After the thermoplastic liner is inserted into the tubing it expands and conforms to the contours of the internal surface of the pipe. An excess of liner material extends from both ends of the pipe. This liner material is then heated and formed in a way that it covers both ends of the tubing. The result of this procedure is a seamless, continuous thermoplastic lining in every part of the tubing.[65]

To prevent imperfections, the threads are visually inspected on the tubing as well as on the couplings. This effort is carried out to maximize the reusability of the steel

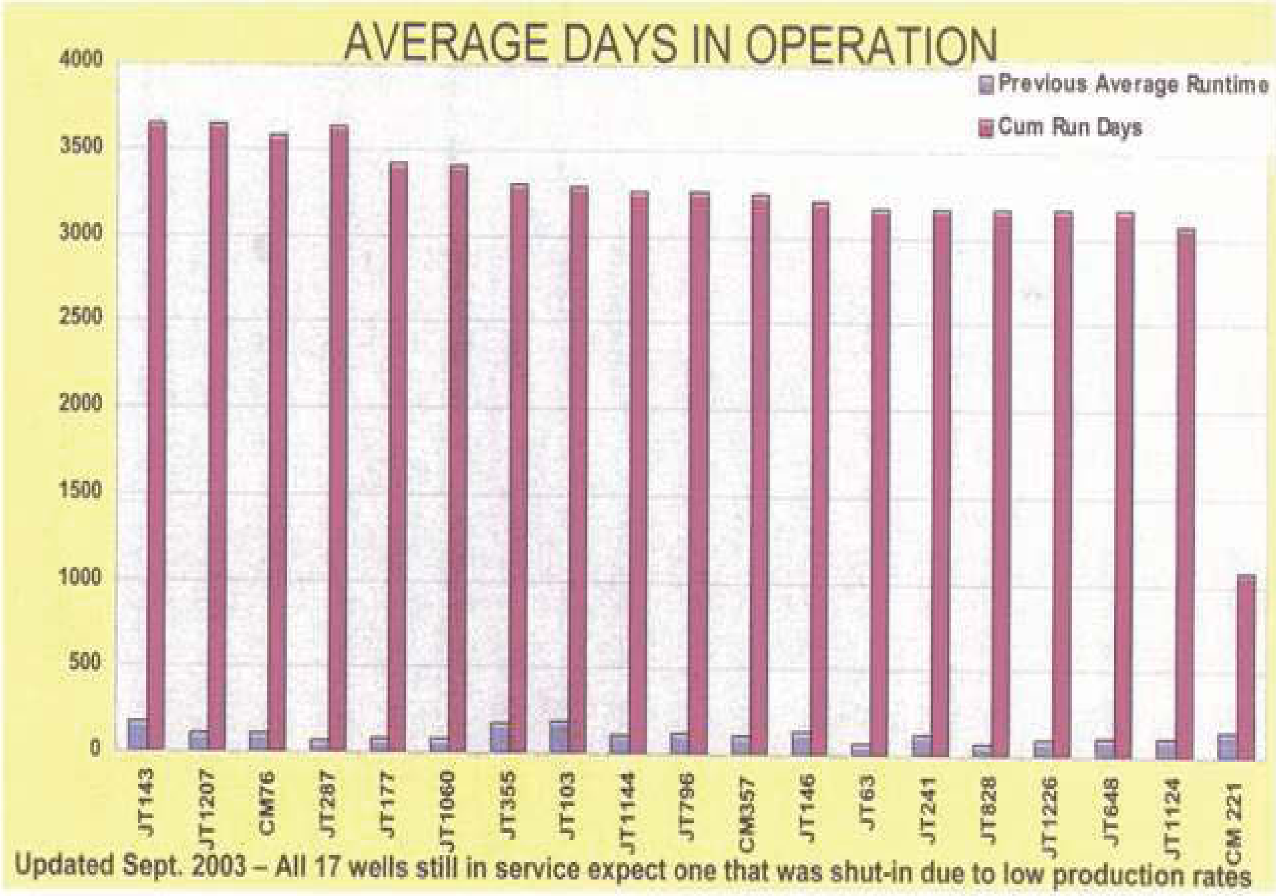
[63] Cf. Davis (2003), p.1 et sq.
[64] www.westernfalcon.com
[65] Cf. Davis (2003), p.2.

tubulars. An API ring gauge is also used to inspect the tube threads and an API plug gauge is used to evaluate the couplings. In the case that the threads do not fit with the API criteria, it does not require great costs to repair them. With this process the tubing connections should be prevented to be a premature failure point, and it also guarantees the longevity of the lined tubing. The aim of this whole lining procedure is to make the steel tubing a completely reusable element and to make sure that you do not need any replacement, as long as you do not have unusual conditions such as improper handling, misuse or external corrosion.[66]

Two examples from different regions in the world show the significant effect of the employment of thermoplastic tubular liners on the tubing runtime. The first example is the application of lined tubings in the South eastern Permian Basin. This sedimentary basin is located in the western part of Texas, U.S.A. Before the lined tubings had been installed the average tubing life was 110 days. Then seventeen production wells were completed with lined tubings. The depths of these wells ranged between 2,800 and 3,000 feet. Afterwards the annual workover frequency, which includes workovers due to all failures not just tubing failures, was reduced from 4.3 workovers per well before installation to 0.59 workovers per well after the installation. The tubing related workovers could be increased from before 110 days to an average run time of approximately 3,500 days, as it is shown in Fig. 4-3. The last well on the chart with the name CM221 was shut-in due to low production rates, so it was excluded from the study.[67]

[66] Cf. Davis (2003), p.2 et sq.
[67] Cf. Davis (2003), p.3.

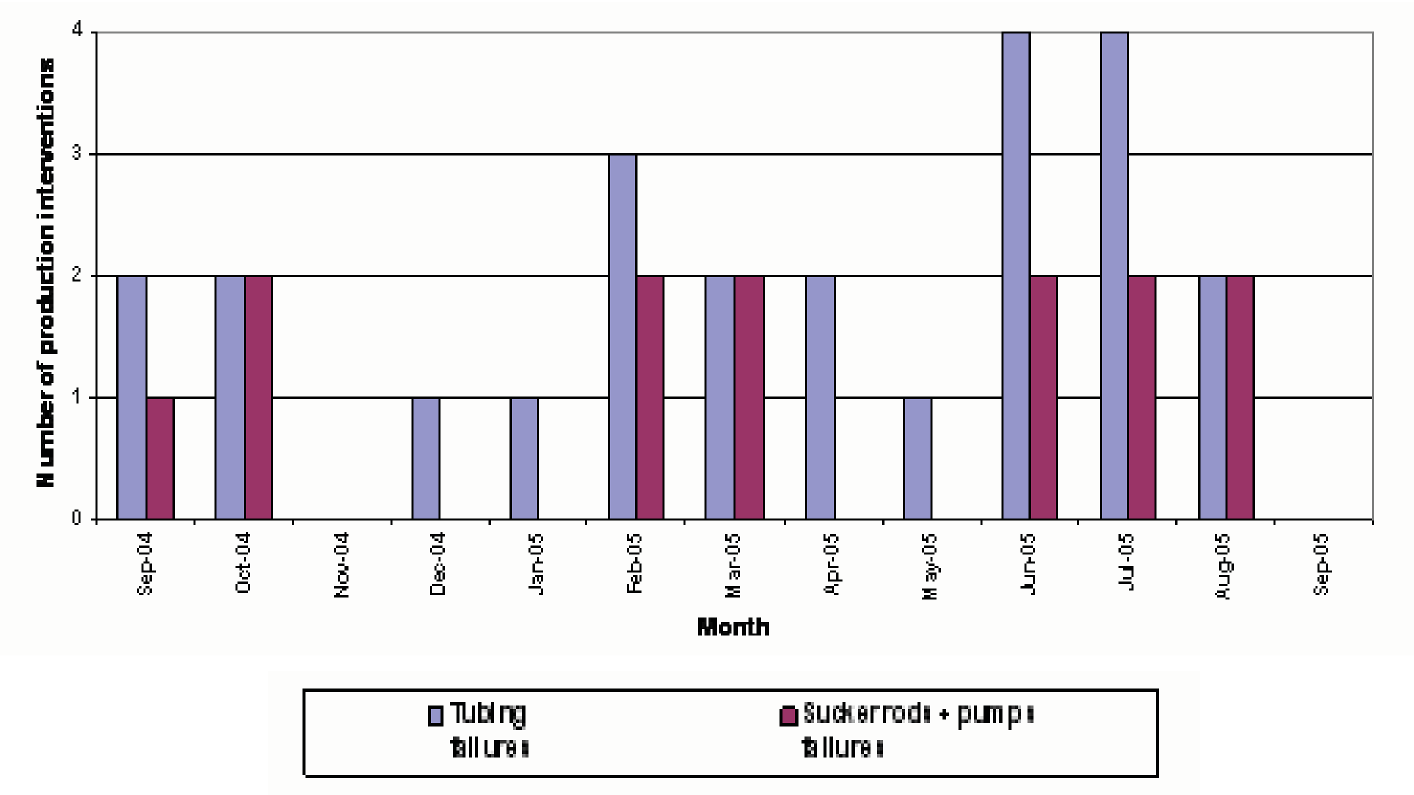
Fig. 4-3 Tubing Runlife before and after lined tubing installation[68]



The second example refers to a well in Romania named 805 Moreni. Fig. 4-4 shows the failure frequency of the well before thermoplastic tubular liners were installed. In comparison with this situation Fig. 4-5 shows the failure frequency of the well after the installation of the lined tubings. The charts distinguish between two types of failures: tubing failures and sucker rod failures, which also include pump failures. On the chart the tubing failures are shown in blue color and the sucker rod failures are shown in red color.[69]

[68] From Davis (2003), p.6.
[69] Cf. Dumitru (2006), p.13.

Fig. 4-4 Failure frequency before usage of thermoplastic tubular liners[70]

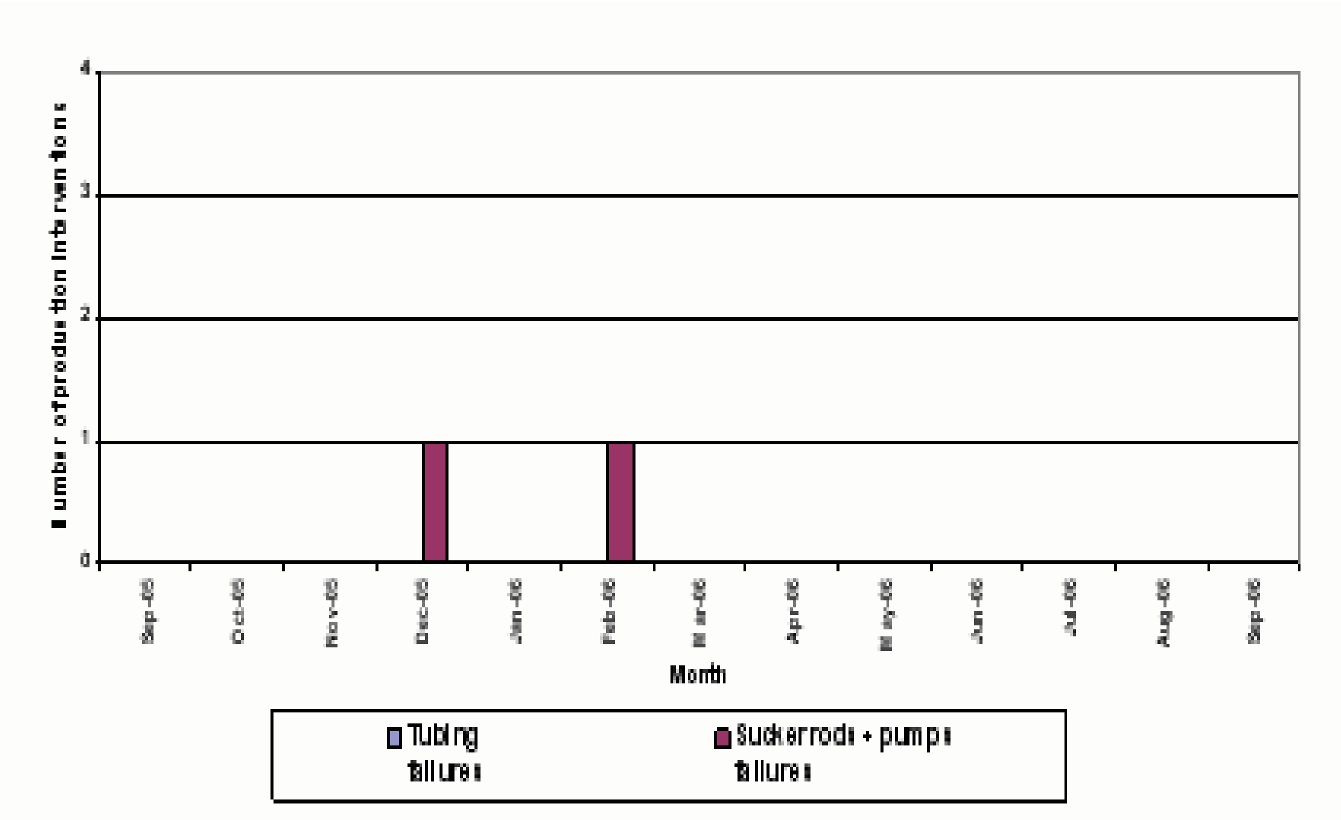


The charts show that after the installation of thermoplastic tubular liners the tubing failures could be reduced from 24 during the time period of September 2004 to September 2005 to a failure frequency of 0 during the time period of September 2005 to September 2006. The charts also show that the sucker rod failures could be reduced from 13 during the time period of September 2004 to September 2005 to a failure frequency 2 during the time period of September 2005 to September 2006. The thermoplastic tubular liners also influence the sucker rod failure frequency, because they reduce the wear of the sucker rods along the tubing wall. Due to these actions the average runtime of sucker rod pumped wells in Romania could be increased to 600 days until the end of April 2007.

These figures show that a significantly high intervention frequency reduction can be achieved by the employment of thermoplastic tubular liners. For this reason OMV plans to equip a certain percentage of wells with this technology. The planned employment of the thermoplastic tubular liners is explained in detail in chapter 5.

[70] From Dumitru (2006), p.13.

Fig. 4-5 Failure frequency after usage of thermoplastic tubular liners[71]



4.4 Wall thickness survey

The wall thickness survey is carried out with the Tubing Vetcoscope C. This is a fully computerized tubing inspection system, which has also been proven in the field. It inspects tubular goods for transversely oriented defects and pitting corrosion by means of the electromagnetic stray flux leakage method. It also detects 'Even wear and Rod wear' by measuring wall thickness by using gamma radiation which penetrates the walls. The tubing dimensions which can be used for the system range from 1.66 inch to 3.5 inch. The pipe ends have to be inspected manually before or after the Electro-Magnetic Inspection and the Gamma through wall radiation.[72]

[71] From Dumitru (2006), p.13.
[72] Cf. Tuboscope Vetco (2005), p.2.

4.4.1 Electromagnetic Inspection (EMI)

The EMI unit is used for the detection and location of defects in seamless pipes. After loading the pipes from the pipe rack, they are centralized and two pinch roller systems drive the pipe through the inspection system. By using the electromagnetic stray flux leakage method, defects in the pipe are detected. This method is based on the magnetization of the pipe by a magnetic DC field in longitudinal direction. Defects in the pipe cut the field lines and cause a flux leakage. This flux leakage induces a signal voltage in the sensors, which are encircling the pipe. The amplitude of the signal depends on the form of the defect, the degree and the velocity of the magnetization. The results of the EMI inspection are displayed on a VGA color monitor.[73]

4.4.2 Wall thickness measuring system (WTS)

The wall thickness radiation system consists of a gamma radiation source and a scintillation counter opposite. These devices are placed in a rotating head. The head rotates at a constant number of revolutions per minute, while the inspected pipe is driven through it. This procedure leads to a helical scanning of the pipe.[74]

The source emits gamma rays which penetrate both pipe walls. The scintillator on the opposite side measures the absorption of the gamma rays. Wall thicknesses from 2.6 mm to 15 mm can be measured with this system. Taking even wear into account the accuracy of the measurement is 0.2 mm. Rod wear which is larger than 15% from the nominal wall thickness can be detected and classified into a maximum of five rod wear groups. These rod wear groups are often chosen between 0 – 15%, 15%-30%, 30%-50%, 50%-75% and larger than 75%.[75]

After the measurement, the pipes are marked with three different colors, which are white, blue and red. A pipe which shows a wear of maximal 30% can still be used and is marked with white color. A pipe with a wear between 30% and 50% is restricted serviceable and is marked with blue color. Pipes which are marked with red color have a wear of greater than 50% and have to be taken out of service.[76]

OMV intends to introduce the wall thickness survey in Romania to identify the tubings which can still be used. The planned employment of the wall thickness survey is described in detail in chapter 5.

[73] Cf. Tuboscope Vetco (2005), p.4.
[74] Cf. Tuboscope Vetco (2005), p.4.
[75] Cf. Tuboscope Vetco (2005), p.4 et sq.
[76] According to statements of experts.

5 The calculation model

5.1 General information

The calculation model of this thesis was created to calculate the savings and the production increase due to a lower number of interventions per year at sucker rod pumped wells in Romania. The model refers to the 7,579 sucker rod pumped wells in Romania. The time period of the model is 5 years. It was calculated for an oil price of $60, which was varied between $20 and $100 during the Monte Carlo Simulation.

The savings can be more accurately described as the difference in the net present value of the current situation and the planned situation in Romania. That means that in the model, the net present value is once calculated assuming an intervention frequency of 10 for the next five years and then it is evaluated for an assumed, decreased number of interventions per year. The difference of these net present values shows then the savings that could be realized by the introduction of different planned actions in Romania.

A production increase can also be realized by decreasing the number of interventions per year, because less interventions means more production time and hence a production increase for the wells which are affected by the planned future actions. As already mentioned, this decreased intervention frequency was realized by the usage of new materials and the employment of new technologies.

The new material which is planned to be installed in Romania includes new grade J-55 tubings, new grade *D special* sucker rod strings, with spray metal couplings, which are a mechanical devise to connect the single parts of the sucker rod string, as well as protectors for the sucker rod strings. The protectors are used to centralize the sucker rod string in the well.

The new technologies, which OMV plans to introduce in Romania, are the employment of corrosion inhibitors, thermoplastic tubular liners and the introduction of a wall thickness survey. The intervention frequency decrease from the actual frequency of 10 interventions per year to certain values in the next years for each planned action was assumed very conservatively to guarantee realistic outputs of the calculation model. The savings and production increases are calculated for three different planned actions. Additionally for each of the planned actions three cases have been calculated – a best case, a worst case and a most realistic case – referring to the realization of the actions according to logistics and deliverability.

The first planned action is the installation of new tubing material at a certain percentage per year. This percentage differs for the best, the worst and the most realistic cases. The new tubing material is also equipped with thermoplastic tubular liners to increase their durability. Concerning the old equipment a wall thickness survey is carried out to find the tubings which can still be used, and therefore installed in other wells. That means that for the wells which are affected by the tubing exchange the complete tubing string has been exchanged with new material in the model, because no one is able to predict the number of tubings which can still be used.

The second planned action is to install new sucker rod strings at a certain percentage per year. Again, this percentage is differentially chosen for the best, the worst and the most realistic cases. They are also not built in by exchanging just the broken parts of the well, but the new sucker rod string material is installed by exchanging complete sucker rod strings. Every new rod is also equipped with three new rod guides to centralize the sucker rod string. Additionally every newly installed sucker rod string is also equipped with a repaired sucker rod pump.

The third planned action concerns the employment of corrosion inhibitor for a certain number of wells. It includes the installation of a certain number of inhibitor treatment pumps per year and the purchase of the corrosion inhibitor. The number of inhibitor treatment pumps was again varied to display a best, worst and most realistic case.

On the basis of the preceding three planned actions, a fourth case was calculated, which combines the three most realistic cases. The fourth case considers the purchase of the materials for all of the most realistic cases and shows how the savings and production increases can be realized by an assumed intervention frequency decrease for the entire 7,579 sucker rod pumped wells.

5.2 Description of intervention basic data

The basic data concerning interventions have been used as input data for calculation of the annual production increase, annual revenues and annual savings due to the reduced number of interventions. They have been calculated in the same way for all planned future actions.

The necessary basic data to calculate the annual savings and the annual production increase due to the employment of new technologies include:

- **the total number of wells in Romania,**
- **the number of sucker rod pumped wells,**
- **the average costs of an intervention,**
- **the actual average number of interventions per year,**
- **the average intervention duration,**
- **the total oil production per day,**
- **the assumed intervention frequency decrease for each calculated case and**
- **the crude oil price.**

During the creation of the thesis, the crude oil price ranged between \$55 and \$65 per bbl. For this reason the crude oil price has been assumed as \$60 per bbl for the model and during the simulation it was varied between \$20 and \$100. 1 Dollar has been converted to 1 Euro by a factor of 0.75. That means 1 Dollar is equal to 0.75 Euro.

If a failure occurs at a sucker rod pumped well, it usually takes some time until the repair process for this sucker rod pumping unit begins. This 'waiting time' of a well for an intervention is the so-called dead time until an intervention takes place. This dead time differs for each well and strongly depends on the production rate of a certain well. That means that a well with a significantly high production rate of, for example, 15 tons per day has a lower dead time than one with a low production rate of, for example, 0.5 tons per day. Due to the fact that it is very difficult to consider all these different dead times in a theoretical calculation model an **average weighted dead time of 6 days** per well has been chosen for the model. That means that in the model it is assumed that after a failure occurs, the average well stands latent for 6 days, until an intervention is carried out.

Another important aspect that has to be taken into account is the fact that, after an intervention, it takes a well some time to reach 100% of its usual production again. According to statements of experts, a well produces on average 15% less oil during this start-up time than during the normal production time. For the calculation model an average **start up time of 14 days** was assumed. Consequently, in these 14 days an average well produces 15% less than normal, which means an average **production loss of 15%** during these 14 days. For a better understanding, all the input data for the calculation of the annual savings and the annual production increases, which are written above in bold are listed again on Tab. 5-1. With the exception of the total oil production per year, which is displayed on Tab. 5-3 and the assumed intervention frequency decrease for each calculated case, which are represented in subsequent chapters.

Tab. 5-1 Input data for the calculations of annual savings and production increase due to the employment of new technologies

Total number of wells in Romania	9,540	[ ]
Number of sucker rod pumped wells	7,579	[ ]
Average costs of an intervention	2,271.20	[Euro/intervention]
Actual average number of interventionsper well per year	10	[Interventions/year]
Average intervention duration	27.3	[hours]

Crude oil price	60	[$]
Average weighted dead time of a well	6	[days]
Average time until 100% of the production are reached again	14	[days]
Average production losses due to start up effect	15	[%]

The total number of 9,540 wells in Romania and the number of sucker rod pumped wells have already been mentioned in preceding chapters.

The average costs of 2,271.20 Euro per intervention have been calculated, as also already mentioned in the introduction of the thesis by evaluating the average intervention costs of eight operating regions in Romania. These eight operating regions are unit Ticleni, unit Craiova, unit Suplac, unit Arad, unit Zemes, unit Moinesti, unit Braila and unit Petromar. For the thesis the following data of these regions were available:

- **the average time period between two interventions in days**
- **the average duration of an intervention in hours and**
- **the average costs of an intervention in RON.**

The currency RON has been converted to Euro by a factor of 0.28, because 1 RON is equal to 0.28 Euro. All these data are shown on Tab. 5-2. By using these data the average number per interventions per well per year, average duration and the average costs of an intervention in Romania have been calculated.

The average number of interventions per well per year has been calculated by summing up the given time periods between two consecutive interventions, creating the average of them and dividing 365 by this average. The given time periods between two consecutive interventions last from the end of one intervention to the end of the next intervention. That means that they include the production time, the dead time and the intervention time. This calculation has led to the actual intervention frequency of 10 intervention per year per well.

The average duration of an intervention in Romania has again been calculated by summing up the given durations of interventions in different regions and averaging them. The average costs have been calculated in the same manner. Afterwards the costs in RON have been converted to Euro.

Tab. 5-2 Intervention data from different regions in Romania[77]

Region name	Average time period between 2 interventions	Average duration of an intervention	Average costs of an intervention	
	[days]	[hours]	[RON]	[Euro]
Unit Ticleni	39,0	23,6	5.642,2	1.579,8
Unit Craiova	36,0	57,6	11.725,2	3.283,1
Unit Suplac	18,4	14,3	4.303,5	1.205,0
Unit Arad	67,0	22,7	3.718,0	1.041,0
Unit Zemes	27,9	8,0	1.018,8	285,3
Unit Moinesti	24,8	8,3	1.051,1	294,3
Unit Braila > 1.000m		50,3	21.931,8	6.140,9
Unit Braila < 1.000m		33,2	15.500,0	4.340,0
Unit Petromar	0,0	0,0	0,0	0,0
Sum:	213,1	218,0	64.890,5	18.169,3
Average:	35,5	27,3	8.111,3	2.271,2
Average number of interventions/well/year:	10,3			

The Romanian oil production is characterized by an annual decline of 10%. Consequently the daily production is also reduced by 10% per year, as it is represented on Tab. 5-3.

Tab. 5-3 Production forecast with a decline of 10% for the next five years

	Current	1st year	2nd year	3rd year	4th year	5th year
Daily Production[bbl/day]	93.000,00	83.700,00	75.330,00	67.797,00	61.017,30	54.915,57

5.2.1 Total production losses caused by an intervention

Based on all these data the production losses due to one single intervention including dead time, intervention time and start up time have been evaluated, as it is displayed on Tab. 5-4. These total production losses caused by one intervention are also necessary for the calculation of annual savings and the production increase due to the employment of new technologies.

Tab. 5-4 Calculation table of intervention basic data

INTERVENTION BASIC DATA	Current	1st year	2nd year	3rd year	4th year	5th year
Total oil production/day [bbl/day]	93.000,00	83.700,00	75.330,00	67.797,00	61.017,30	54.915,57
Total oil production/day [tons/day]	12.687,59	11.418,83	10.276,94	9.249,25	8.324,32	7.491,89
Average production rate/day/well [bbl/day]	9,75	8,77	7,90	7,11	6,40	5,76
Average production rate/day/well [tons/day]	1,33	1,20	1,08	0,97	0,87	0,79
Average intervention duration [days]	1,00	1,00	1,00	1,00	1,00	1,00
Production losses due to intervention [tons]	1,33	1,20	1,08	0,97	0,87	0,79
Averaged weighted dwell time of a well until an interv. [days]	6,00	6,00	6,00	6,00	6,00	6,00
Production losses due to dwell time [tons]	7,98	7,18	6,46	5,82	5,24	4,71
Time until 100% of the production are reached [days]	14,00	14,00	14,00	14,00	14,00	14,00
Proction losses due to the start up effect [%]	15,00%	15,00%	15,00%	15,00%	15,00%	15,00%
Production losses due to the start up effect [tons]	2,79	2,51	2,26	2,04	1,83	1,65
Prod. losses per well (dwell+intervention+ start up time) [tons]	12,10	10,89	9,80	8,82	7,94	7,15
Total oil production of sucker rod pumped wells [tons/day]	10.079,58	9.071,62	8.164,46	7.348,02	6.613,21	5.951,89
Total oil production of sucker rod pumped wells [bbl/day]	73.893,33	66.495,00	59.845,50	53.860,95	48.474,86	43.627,37

[77] On the tables of the thesis the decimal places are marked with a comma and the thousands places are marked with a point

In the first row of this table the years of the calculation model are shown. The first column represents the necessary data to calculate the production losses resulting from an intervention.

The second and the third row of the table show the total Romanian oil production per day in bbl and in metric tons. The calculation model uses a factor of 7.33 to convert metric tons to bbl. That means that 1 metric ton equals to 7.33 bbl.

The next step in the calculation is to evaluate the average production rate per day per well. This has been done by dividing the total oil production rate per day by the total number of wells in Romania, because the total oil production per day refers to all wells and not only to the sucker rod pumped wells. The average production rate has been calculated in bbl per day, shown in the third row of the table, and in tons per day, shown in the fourth row.

During one intervention procedure three types of losses must be distinguished:

- **Production losses due to the intervention itself**
- **Production losses during the dead time**
- **Production losses during the start up time, until the production reaches again 100%.**

The production losses during the intervention time can be calculated by multiplying the average production rate per day per well and average duration of an intervention. The average duration of an intervention is 27.3 hours, as it displayed on Tab. 5-2. This value has been rounded in the calculation to 1 day. The production losses during the average intervention time of one day in tons are displayed for all years in the seventh row of the table.

In the same manner, that means that by multiplying the average production rate per day per well with the average weighted dead time of a well, the production losses during the dead time, which is the time an average well 'waits' for an intervention, have been calculated. The results in tons are shown in the ninth row of the Tab. 5-4. As already explained the start up effect after an intervention causes a reduced production for several days. The production losses due to this start up effect have been calculated as the product of

- **the average production rate per day per well,**
- **the average time of 14 days until 100% of the production are reached again and**
- **the production loss in percent due the start up effect, which is ~15%.**

The results are given in tons in the twelfth row of the table. The total production losses due to one single intervention including dead time, intervention time and start up time have then been evaluated by simply adding up the production losses during the intervention, during the dead time and during the start up time. These total production losses per well are given again in tons in the thirteenth row of the table.

In the last two rows of Tab. 5-4, the total oil production of sucker rod pumped wells in bbl and in tons is shown. This total oil production is the product of the average production rate per day per well and the number of sucker rod pumped wells for each year of the calculation.

5.2.2 Annual revenues for a constant intervention frequency

The next step of the calculation is to evaluate the annual revenues from the oil production under the assumption that nothing would be changed and the annual intervention frequency would remain at 10 interventions per year. Tab. 5-5 displays these annual revenues, which have been calculated by multiplying the annual oil production of sucker rod pumped wells in bbl by the actual crude oil price in Euro. The annual oil production was evaluated by multiplying the total oil production of the sucker rod pumped wells per day, which is displayed on Tab. 5-4, with the factor 365. The crude oil price cannot be assumed as a static value for the whole time period of the calculation model. For this reason the variability of the crude oil price was considered during the Monte Carlo Simulation.

Tab. 5-5 Annual revenues for 7,579 sucker rod pumped wells at an intervention frequency of 10 interventions per year.

	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Number of interventions/well/year	10	10	10	10	10	10
Annual oil production of sucker rod pumped wells [bbl/year]	26.967.416,67	24.270.675,00	21.843.607,50	19.659.246,75	17.693.322,08	15.923.989,87
Revenue [Euro/year]	1.213.533.750,00 €	1.092.180.375,00 €	982.962.337,50 €	884.666.103,75 €	796.199.493,38 €	716.579.544,04 €

As already mentioned the annual cash flows of a long term investment are calculated as the difference between the annual revenues and the annual costs for the investment. The revenues assuming 10 interventions per year have already been calculated. Considering this scenario, no new material is bought. That means that for this scenario the investment costs are zero. Consequently the annual revenues are equal to the annual cash flows.

5.3 Corrosion Inhibitor

For the calculation of the savings and the production increase a certain reduction of the intervention frequency due to the employment of corrosion inhibitors has been assumed. Different tables have been created for the best, the worst and the most realistic cases. The assumed best case is shown on Tab. 5-6.

Tab. 5-6 Development of the intervention frequencies due to corrosion inhibitor employment in the best case

Number of pumps	1st year	2nd year	3rd year	4th year	5th year
2.500	7,5	5	5	4	4
2.500	10	7,5	5	5	4
2.579	10	10	10	10	10

Concerning the best case of corrosion inhibitor employment, 2,500 inhibitor treatment pumps are installed in the first year and another 2,500 pumps are installed in the second year. The first row of the Tab. 5-6 shows the years of the calculation model and the first column represents the annually installed inhibitor treatment pumps. The other cells of the table show the assumed reduced number of interventions per well per year due to the employment of corrosion inhibitor.

Tab. 5-6 displays that in the best case 2,500 inhibitor treatment pumps are installed in the first year. For these 2,500 wells an intervention frequency of 7.5 interventions per well per year is assumed in the first year of installation. Generally, not all 2,500 wells can be equipped at the same time, and so the assumed intervention frequency in the first year is higher than in the following years. The other 5,079 wells are not affected by the installation of inhibitor pumps in the first year, and so their frequency of interventions still remains at 10 interventions per well per year as can be seen in the second column of the table. For the wells which are equipped with inhibitor treatment pumps in the first year the intervention frequency reduces to 5 interventions per well per year in the second year and to 4 interventions per well per year in the fourth year. This development can be observed in the second row of the table.

In the second year, an additional 2,500 pumps are installed, which reduces the intervention frequency of these wells to 7.5 in the second year. The frequency of interventions for these 2,500 wells has, starting from the second year, the same development as the intervention frequency of the 2,500 wells which were equipped in the first year. This fact can be seen in the third row of Tab. 5-6. Concerning the best case altogether 5,000 wells are equipped with inhibitor treatment pumps and the installation is finished after the second year. Consequently 2,579 wells are not equipped with inhibitor pumps and their intervention frequency keeps on 10 interventions per well per year.

The worst case considers that only 500 inhibitor treatment pumps are installed per year and so after the fifth year 2,500 pumps would be installed. The assumed intervention frequency decrease for the worst case is displayed on Tab. 5-7.

Tab. 5-7 Development of the intervention frequencies due to corrosion inhibitor employment in the worst case

Number of pumps	1st year	2nd year	3rd year	4th year	5th year
500	7,5	5	5	4	4
500	10	7,5	5	5	4
500	10	10	7,5	5	5
500	10	10	10	7,5	5
500	10	10	10	10	7,5
5.079	10	10	10	10	10

The scheme of the table for the worst case is the same as for the best case. Its first row also shows the years of the calculation model and the first column represents the number of installed inhibitor pumps. The development of the intervention frequencies is also the same, but with the difference that in the first year just 500 wells are equipped with the pumps, and so the intervention frequency in the first year can only be reduced to 7.5 for 500 wells. For these wells the number of interventions decreases again from 7.5 to 5 in the second year and from 5 to 4 in the fourth year.

The development of the intervention frequency for other wells which are later equipped with the pumps is the same. But with a delay of, for example, one year if they are equipped with the pumps in the second year, or with a delay of four years if they are equipped in the fifth year, as it is displayed on Tab. 5-7. The number of interventions per well per year stays at 10 until the installation is fulfilled.

In the worst case 5,079 wells are not affected by the installation of inhibitor treatment pumps, therefore their intervention frequency always remains at 10 per well per year. Tab. 5-8, which represents the intervention frequencies for the most realistic case, has exactly the same structure as the two preceding tables, but with the difference that in the assumed realistic case 1,000 pumps are installed in the first year, 2,000 pumps are installed in second year and another 2,000 pumps are installed in the third year.

Tab. 5-8 Development of the intervention frequencies due to corrosion inhibitor employment in the most realistic case

Number of pumps	1st year	2nd year	3rd year	4th year	5th year
1.000	7,5	5	5	4	4
2.000	10	7,5	5	5	4
2.000	10	10	7,5	5	5
0	10	10	10	7,5	5
0	10	10	10	10	7,5
2.579	10	10	10	10	10

This table in the calculation model is able to be changed to any other desired numbers of pumps installed in every one of the five years. That is the reason why there are an additional two rows, the fifth and the sixth, with zero pumps installed. As long as this numbers are zero the rows have no influence on the calculation model. If they are changed to any other desired number of pumps, that should be installed in the fourth or fifth year, the model automatically considers these changes.

The number of unaffected wells is the same as for the best case. The difference from the best case is that in the most realistic case a lower number of pumps is installed per year. That means that the installation of the 5,000 pumps lasts longer, namely 3 instead of 2 years, and consequently the decrease of the intervention frequency for all of the 5,000 wells occurs more slowly.

These three tables are the starting point and basis of the calculations for the employment of corrosion inhibitor. Based on these assumed intervention frequencies, the capital expenditures and the operating expenditures for the corrosion inhibitor employment have been calculated, as well as the savings and the production increase due to the lower number of interventions per year.

5.3.1 Costs of the corrosion inhibitor

The necessary data to calculate the capital expenditures, the so called capex, and the operating expenditures, the so called opex, are the price of the corrosion inhibitor per liter, the dosage of the corrosion inhibitor per liter, the total oil production per day for all 9,540 wells in Romania, the water cut, which is the fraction of the produced water to the produced oil, the inhibitor treatment pump skid price and the number of installed inhibitor treatment pumps. All these data are based on the advice of experts. These data are listed on Tab. 5-9.

Tab. 5-9 Necessary data to calculate the capex and opex of the corrosion inhibitor employment

Inhibitor price	2.5	[Euro/liter]
Dosage	35	[ppm]
Total oil production /day	93,000 (with annual decline of 10%)	[bbl/day]
Water cut	70	[%]
Inhibitor treatment skid (pump) price	5,000	[Euro/skid]
Number of installed pumps	5,000 (2,500; 2,500; 0; 0; 0)	Best case
	2,500 (500; 500; 500; 500; 500)	Worst case
	5,000(1,000; 2,000; 2,000; 0; 0)	Most realistic case

Tab. 5-10 Best case calculation of the capex and opex for the corrosion inhibitor

BEST CASE	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Inhibitor treatment pumps/year:	2.500	2.500				
Capex/year:	12.500.000,00 €	12.500.000,00 €				
Total number of pumps:		2.500	5.000	5.000	5.000	5.000
Inhibited fraction:		0,6	0,8	0,8	0,8	0,8
Inhibited volume of oil [bbl/day]		47.081,3	56.497,5	50.847,8	45.763,0	41.186,7
Inhibited volume of water [bbl/day]		109.856,3	131.827,5	118.644,8	106.780,3	96.102,2
Inhibited total volume [bbl/day]		156.937,5	188.325,0	169.492,5	152.543,3	137.288,9
Inhibitor volume [bbl/day]		5,5	6,6	5,9	5,3	4,8
Inhibitor volume [liter/day]		873,4	1.048,0	943,2	848,9	764,0
Inhibitor volume [liter/year]		318.775,4	382.530,4	344.277,4	309.849,7	278.864,7
Inhibitor costs/day:		2.183,39 €	2.620,07 €	2.358,06 €	2.122,26 €	1.910,03 €
Maintenance:		1.250.000,00 €	2.500.000,00 €	2.500.000,00 €	2.500.000,00 €	2.500.000,00 €
Opex/year:		2.046.938,43 €	3.456.326,12 €	3.360.693,51 €	3.274.624,16 €	3.197.161,74 €

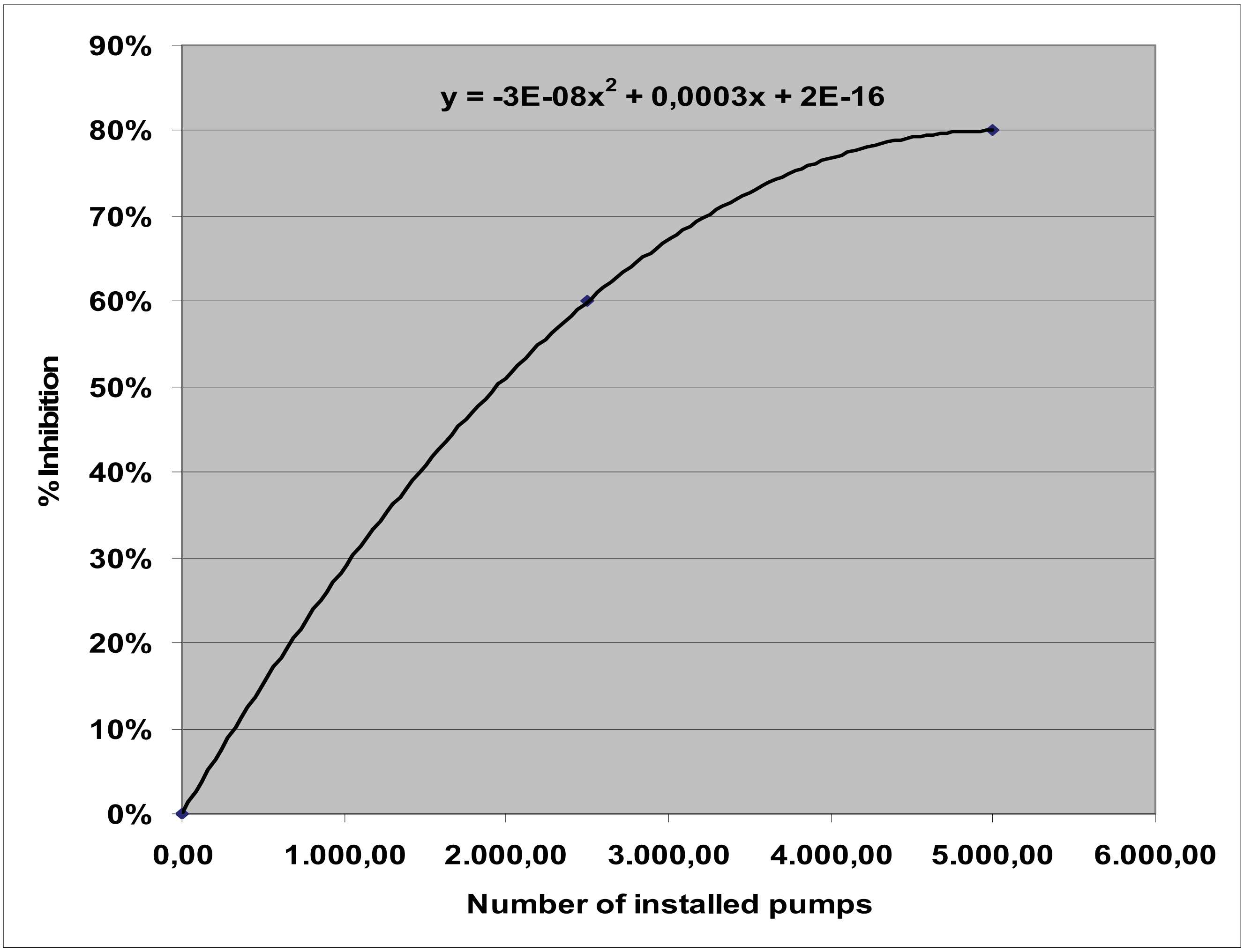
Tab. 5-10 displays the calculation of the capex and opex for the corrosion inhibitor in the best case. As already mentioned 2,500 pumps are installed in the first year and in the second year in the best case. The first row of the table shows the years of the calculation and the first column shows the necessary calculation steps to evaluate the capex and the opex.

The capex always have to be spent in the year before the installation of the pumps takes place. That means that the 2,500 pumps which are installed in the first year have to be bought at the beginning of every year respectively at the end of the year before. In the same manner the 2,500 pumps that are installed in the second year have to be bought in the first year.

As Tab. 5-9 shows, the costs for an inhibitor treatment pump are 5,000 Euro. Consequently the capex for 2,500 pumps installed in the first year and 2,500 pumps installed in the second year amount to 12.500,000.00 Euro in the year before the first installation and 12.500,000.00 Euro in the end of the first year. These figures are shown in the third row of the table.

The fourth row represents the number of installed inhibitor treatment pumps. In Romania, about 30% of the 9,540 wells produce two thirds of the total production. This fact is displayed on Fig. 5-1 which shows the inhibition percentage of the total production versus the number of installed pumps. This chart was created in Excel® by constructing three estimated points and then approaching these points by a curve. The curve was created by polynomial regression. The input data for the three points are based on statements of experts. They assure that by installing 2,500 pumps it is possible to inhibit 60% of the total production and by installing 5,000 pumps it is possible to inhibit 80% of the total production. The reason for this non-direct proportional development is that some wells have a much higher production rate than others. The third point is based on the simple fact that by installing no pumps 0% of the total production would be inhibited.

Fig. 5-1 Inhibition percentage of the total production versus number of installed pumps



The above curve is described by the following equation:

$$y = -3 * 10^{-8} * x^2 + 0.003 * x + 2 * 10^{-16}$$

y = inhibition percentage of the total production

x = number of installed pumps

The fifth row of Tab. 5-10 shows the inhibited fraction of the total production due to the already installed inhibitor treatment pumps. This fraction was calculated by using the above equation.

The inhibited volume of oil in bbl per day is displayed in the sixth row of Tab. 5-10. It was calculated for first year by multiplying the inhibited fraction of the total oil production with the daily oil production. For the other years it was calculated after the same procedure.

The seventh row of Tab. 5-10 shows the inhibited volume of water per day. It was calculated for each year by using the following formula:

$$\textit{Inhibited volume of water} = (\textit{Inhibited volume of oil} * \textit{Water cut})/(1 - \textit{Water cut})$$

The eighth row of Tab. 5-10 represents the inhibited volume in barrel per day for each year which is the sum of the inhibited volume of oil per day and the inhibited volume of water per day. The next row of the table displays the inhibitor volume in bbl injected per day. It was calculated by multiplying the total inhibited volume per day by 0.000035, which equals to 35 ppm. The tenth row shows this inhibitor volume in liter per year, which has been calculated by multiplying the inhibitor volume injected per day by 365.

The next row represents the inhibitor costs per day, which have been evaluated as the product of the inhibitor volume injected in liters per day and the inhibitor price per liter.

The maintenance of the inhibitor treatment pumps was also taken into account in the calculation. According to experts from OMV, they amount to about 10% of the already spent capex. So these maintenance costs have been calculated by multiplying the already spent capex with 0.1. The results of these calculations for each year are shown in the twelfth row of the table.

At the end the opex per year for the employment of the corrosion inhibitor have been calculated. They have been evaluated by multiplying the injected inhibitor volume per year with the inhibitor price per liter and adding to this product the annual maintenance costs. The opex per year are represented in the last row of the table.

The capex and opex for the worst and the most realistic cases have been calculated in the same manner. The only difference in the calculations was the number of installed inhibitor treatment pumps per year, as can be seen in the second row on Tab. 5-11 and Tab. 5-12.

Tab. 5-11 Worst case calculation of the capex and opex for the corrosion inhibitor

WORST CASE	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Inhibitor treatment pumps/year:	500	500	500	500	500	500
Capex/year:	2.500.000,00 €	2.500.000,00 €	2.500.000,00 €	2.500.000,00 €	2.500.000,00 €	2.500.000,00 €
Total number of pumps:		500	1.000	1.500	2.000	2.500
Inhibited fraction:		0,1	0,3	0,4	0,5	0,6
Inhibited volume of oil [bbl/day]		11927,25	20339,10	25932,36	29288,30	30890,01
Inhibited volume of water [bbl/day]		27830,25	47457,90	60508,82	68339,38	72076,69
Inhibited total volume [bbl/day]		39757,50	67797,00	86441,18	97627,68	102966,69
Inhibitor volume [bbl/day]		1,39	2,37	3,03	3,42	3,60
Inhibitor volume [liter/day]		221,26	377,29	481,05	543,30	573,01
Inhibitor volume [liter/year]		80756,43	137710,96	175581,48	198303,78	209148,52
Inhibitor costs/day:		553,13 €	943,23 €	1.202,61 €	1.358,25 €	1.432,52 €
Maintenance:		250.000,00 €	500.000,00 €	500.000,00 €	500.000,00 €	500.000,00 €
Opex/year:		451.891,07 €	844.277,40 €	938.953,69 €	995.759,46 €	1.022.871,31 €

Tab. 5-12 Most realistic case calculation of the capex and opex for the corrosion inhibitor

REALISTIC CASE	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Inhibitor treatment pumps/year:	1.000	2.000	2.000	0	0	0
Capex/year:	5.000.000,00 €	10.000.000,00 €	10.000.000,00 €	- €	- €	- €
Total number of pumps:		1.000	3.000	5.000	5.000	5.000
Inhibited fraction:		0,3	0,6	0,8	0,8	0,8
Inhibited volume of oil [bbl/day]		22599,00	47457,90	50847,75	45762,98	41186,68
Inhibited volume of water [bbl/day]		52731,00	110735,10	118644,75	106780,28	96102,25
Inhibited total volume [bbl/day]		75330,00	158193,00	169492,50	152543,25	137288,93
Inhibitor volume [bbl/day]		2,64	5,54	5,93	5,34	4,81
Inhibitor volume [liter/day]		419,21	880,34	943,23	848,90	764,01
Inhibitor volume [liter/year]		153012,18	321325,58	344277,40	309849,66	278864,70
Inhibitor costs/day:		1.048,03 €	2.200,86 €	2.358,06 €	2.122,26 €	1.910,03 €
Maintenance:		500.000,00 €	1.500.000,00 €	1.500.000,00 €	1.500.000,00 €	1.500.000,00 €
Opex/year:		882.530,45 €	2.303.313,94 €	2.360.693,51 €	2.274.624,16 €	2.197.161,74 €

5.3.2 Production increase and intervention cost savings for the best case

The next step of the calculation is the evaluation of the annual production increase, annual revenues and annual intervention cost savings assuming a decreased intervention frequency. They have been calculated for the assumed best, worst and most realistic cases of the corrosion inhibitor employment. These annual revenues must be higher, because a reduced number of interventions means more production and hence more revenue. But the savings do not result from the increase in production only, because fewer interventions also mean less intervention costs and this fact leads to additional savings due to the reduced number of interventions. As already mentioned in preceding chapters in the best case 5,000 inhibitor treatment pumps are installed in the first two years of the calculation model, 2,500 pumps in the first year and 2,500 pumps in the second year. The assumed development of the intervention frequencies due to corrosion inhibitor employment in the best case is displayed on Tab. 5-6. For the calculation of the annual revenues and the intervention cost savings due to a reduced number of interventions per year, the following procedure has been applied.

The annual production increase, annual revenues and the intervention cost savings have been calculated at first for the 2,500 wells which are equipped in the first year, then for the 2,500 wells equipped in the second year and afterwards for the 2,579 pumps which are not equipped with inhibitor treatment pumps. At the end of the revenue calculations for the best case all three revenues and intervention cost savings have been summed up to receive the total annual revenues and the total intervention cost savings for the best case. Tab. 5-13 shows the calculation table of the annual revenues and the annual savings due to the reduced number of interventions for the 2,500 wells which are equipped in the first year. The first row represents again the years of the calculation model and the first column shows the description of the necessary data for the calculation. The description of the calculation is made for the first year. The annual production increases, annual revenues and annual cost savings due to the reduced number of interventions for the other four years have been calculated in the same manner.

Tab. 5-13 Annual production increase, annual revenues and annual intervention cost savings of the 2,500 wells equipped with inhibitor treatment pumps in the first year.

Inhibitor (Best case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	2.500	wells:				
Intervention costs/well/year [Euro/year]:		17.033,70 €	11.355,85 €	11.355,85 €	9.084,68 €	9.084,68 €
Total intervention costs/year (new) [Euro/year]:		42.584.437,50 €	28.389.625,00 €	28.389.625,00 €	22.711.700,00 €	22.711.700,00 €
Total intervention costs/year (old) [Euro/year]:		56.779.250,00 €	56.779.250,00 €	56.779.250,00 €	56.779.250,00 €	56.779.250,00 €
Production losses/well/year [tons/year]:		81,69	49,01	44,11	31,76	28,59
Total production losses/year [tons/year]:		204.228,23	122.536,94	110.283,24	79.403,94	71.463,54
Total production losses/year [bbl/year]:		1.496.992,92	898.195,75	808.376,18	582.030,85	523.827,76
Total oil production/year (old) [tons/year]:		1.092.209,58	982.988,62	884.689,76	796.220,78	716.598,71
Total oil production/year (old) [bbl/year]:		8.005.896,23	7.205.306,60	6.484.775,94	5.836.298,35	5.252.668,51
Production increase/year [bbl/year]:		498.997,64	898.195,75	808.376,18	873.046,27	785.741,65
Total oil production/year (new) [bbl/year]:		8.504.893,87	8.103.502,35	7.293.152,12	6.709.344,62	6.038.410,16
Revenues / year [Euro/year]:		387.720.224,06 €	364.657.806,13 €	328.191.845,52 €	301.920.508,07 €	271.728.457,22 €
Savings due to reduced interventions/year[Euro/year]:		14.194.812,50 €	28.389.625,00 €	28.389.625,00 €	34.067.550,00 €	34.067.550,00 €

The calculation of the following data was necessary to calculate the annual revenues generated by the production and the annual savings of the 2,500 wells:

- **annual intervention costs per well**
- **annual intervention costs for 7.5 interventions per well for all the 2,500 wells**
- **annual intervention costs for 10 interventions per well for all the 2,500 wells (old scenario)**
- **annual savings due to the reduced number of interventions**
- **annual production losses per well**
- **annual production losses of the 2,500 wells**
- **annual oil production of the 2,500 wells**
- **annual oil production of the old scenario**
- **annual production increase**
- **annual revenue**

At first, the **annual intervention costs per well** have been calculated. These costs are the product of the assumed average number of interventions per well per year and the average intervention costs of 2,271.20 Euro. For the first year the number of interventions per well is, for example, 7.5 as it is displayed on Tab. 5-6. For the other years these intervention costs have been calculated with other intervention frequencies, which are also displayed on Tab. 5-6.

To calculate the **annual intervention costs for 7.5 interventions per well for all the 2,500 wells**, the intervention costs per well have been multiplied by 2,500. These total intervention costs per year are of course lower for 7.5 interventions per well than they would be for the actual 10 interventions per well per year.

The next step is to calculate the **annual intervention costs for 10 interventions per well for all the 2,500 wells**, which are displayed in the fifth row of the table. The difference of the intervention costs for 10 interventions and for 7.5 interventions are the **savings due to the reduced number of interventions**. These savings are shown in the last row of Tab. 5-13. These savings are just part of the total savings that must not be mistaken with the total savings due to the employment of a corrosion inhibitor, which are calculated as the difference in the net present value of the old and the new scenarios. 'New scenario' means in this context the scenario with the corrosion inhibitor employment and 'old scenario' means the scenario without any changes. In the first year, assuming a 'new' intervention frequency of 7.5 and an 'old' intervention frequency of 10 for the 2,500 wells, the intervention frequency would be reduced on average by 2.5 interventions per well per year.

The next step is to compute the **total production losses of all 2,500 wells** in the first year. At first the **annual production losses per well** have been calculated. They are the total production losses caused by one intervention, including dead time, intervention time and start up time, multiplied by 7.5 for the first year.

After that, this value has been multiplied by 2,500 to get the **total production losses of all 2,500 wells** for the first year. The oil production of 93,000 bbl per day, which was mentioned in preceding chapters, already takes into consideration these production losses, and so they do not have to be subtracted from this number.

Then the **total oil production of the 2,500 wells** for the first year has been calculated. It is the sum of the **total oil production of the old scenario** and the **annual production increase** due to a lower number of interventions.

The total oil production of the old scenario for the first year is the average production rate per well per day times 365 times 2,500. The production increase is calculated as the product of the production losses per intervention per well, the intervention frequency decrease of 2.5 and the number of wells, which are again 2,500.

The **annual revenue** for the first year has then been calculated as the product of the total oil production of the 2,500 wells in the first year and the crude oil price in Euro. They are listed at the end of Tab. 5-13 in Euro per year. As already mentioned, the annual revenues for the other four years have been computed in the same manner.

The next step is the calculation of the revenues for the 2,500 wells equipped with inhibitor treatment pumps in the second year and the calculation of the revenues for the 2,579 wells which are not equipped with pumps.

The annual **revenues generated by the production of the 2,500 wells equipped in the second year** have been calculated according to the same procedure, which has been described in detail for the 2,500 pumps equipped in the first year.

Tab. 5-14 displays the calculation table of the annual revenues and the savings due to the reduced number of interventions for the 2,500 wells which are equipped in the second year.

Tab. 5-14 Annual production increase, annual revenues and annual intervention cost savings of the 2,500 wells equipped with inhibitor treatment pumps in the second year.

Inhibitor (Best case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	2.500	wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	17.033,78 €	11.355,85 €	11.355,85 €	9.084,68 €
Total intervention costs/year (new) [Euro/year]:		56.779.250,00 €	42.584.437,50 €	28.389.625,00 €	28.389.625,00 €	22.711.700,00 €
Total intervention costs/year (old) [Euro/year]:		56.779.250,00 €	56.779.250,00 €	56.779.250,00 €	56.779.250,00 €	56.779.250,00 €
Production losses/well/year [tons/year]:		108,92	73,52	44,11	39,70	28,59
Total production losses/year [tons/year]:		272.304,31	183.805,41	110.283,24	99.254,92	71.483,54
Total production losses/year [bbl/year]:		1.995.990,57	1.347.293,83	808.376,18	727.538,56	523.877,78
Total oil production/year (old) [tons/year]:		1.092.209,58	982.988,62	884.689,76	796.220,78	716.598,71
Total oil production/year (old) [bbl/year]:		8.005.098,23	7.205.308,60	6.484.775,94	5.836.298,35	5.252.668,51
Production increase/year [bbl/year]:		0,00	449.097,88	808.376,18	727.538,56	785.741,65
Total oil production/year (new) [bbl/year]:		8.005.098,23	7.654.404,48	7.293.152,12	6.563.836,91	6.038.410,16
Revenues / year [Euro/year]:		380.265.330,19 €	364.448.201,65 €	328.191.845,52 €	295.372.660,97 €	271.728.457,22 €
Savings due to reduced interventions/year[Euro/year]:		- €	14.194.812,50 €	28.389.625,00 €	28.389.625,00 €	34.067.550,00 €

By observing this table a conspicuous difference to Tab. 5-13 can be recognized. This difference is that there are no savings due to reduced interventions and no production increase in the first year. The reason for this is, that the 2,500 pumps are installed in the second year, and therefore no changes can be observed at these wells in the first year because they still have an intervention frequency of 10 per well per year until the pumps are installed.

The 2,579 wells which are not equipped with inhibitor treatment pumps do not show a production increase or savings due to a lower number of interventions, because their intervention frequency always stays at 10 interventions per year. This fact can be observed on Tab. 5-15. Therefore the production decline is not reduced due to a lower number of interventions, and so it remains at 10% per year for these wells.

Tab. 5-15 Annual production increase, annual revenues and annual intervention cost savings of the 2,579 wells which are not equipped with inhibitor treatment pumps

Inhibitor (Best case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	2.579	wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €
Total intervention costs/year (new) [Euro/year]:		58.573.474,30 €	58.573.474,30 €	58.573.474,30 €	58.573.474,30 €	58.573.474,30 €
Total intervention costs/year (old) [Euro/year]:		58.573.474,30 €	58.573.474,30 €	58.573.474,30 €	58.573.474,30 €	58.573.474,30 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	79,40	71,46
Total production losses/year [tons/year]:		280.909,12	252.818,21	227.536,39	204.782,75	184.304,48
Total production losses/year [bbl/year]:		2.059.063,07	1.853.157,48	1.667.841,73	1.501.057,56	1.350.951,80
Total oil production/year (old) [tons/year]:		1.126.723,40	1.014.051,06	912.645,96	821.381,36	739.243,22
Total oil production/year (old) [bbl/year]:		8.258.882,55	7.432.994,29	6.689.694,86	6.020.725,38	5.418.652,84
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	0,00
Total oil production/year (new) [bbl/year]:		8.258.882,55	7.432.994,29	6.689.694,86	6.020.725,38	5.418.652,84
Revenues / year [Euro/year]:		371.649.714,62 €	334.484.743,16 €	301.036.268,84 €	270.932.641,96 €	243.839.377,76 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	- €

At the end of the calculations for the best case, the total annual oil production, the annual revenues generated by the production and the annual savings due to the reduced interventions per year, represented on Tab. 5-13, Tab. 5-14 and Tab. 5-15, have been summed up to receive the annual production, annual revenues and annual savings for all of the 7,579 sucker rod pumped wells. These results are displayed on Tab. 5-16.

Tab. 5-16 Annual production, annual revenues and annual intervention cost savings of all 7,579 sucker rod pumped wells in the best case

Inhibitor (Best case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	7.579	wells:				
Total oil production/year (new) [bbl/year]:		24.769.672,84	23.190.901,13	21.275.998,11	19.263.806,81	17.495.473,18
Revenues / year [Euro/year]:		1.114.635.780,07 €	1.043.590.550,94 €	957.419.958,88 €	866.225.810,95 €	787.296.292,20 €
Savings due to reduced interventions/year[Euro/year]:		14.194.812,50 €	42.584.437,50 €	56.779.250,00 €	62.457.175,00 €	68.135.100,00 €

It can be seen on this table, that the oil production is still decreasing for the next five years but the **annual oil production** is higher than on Tab. 5-5, which displays the annual oil production for an intervention frequency of 10 interventions per year. That means that the annual production decline of ten percent has been reduced due to the installation of the 2,500 inhibitor treatment pumps. The same trend can be seen by observing the **annual revenues**. They are still decreasing, but the annual revenues are higher than on Tab. 5-5, which also shows the annual revenues for an intervention frequency of 10 interventions per year. The **annual savings due to a reduced number of interventions** are increasing. The reason for this is that the number of interventions is reduced during the time period of the calculation model, and so the savings caused by this reduction are rising.

5.3.3 Production increase and intervention cost savings for the worst case

As already mentioned in preceding chapters, 2,500 inhibitor treatment pumps are installed in the five years of the calculation model in the worst case. That means that 500 pumps are installed in each year. The assumed development of the intervention frequencies due to corrosion inhibitor employment in the worst case is displayed on Tab. 5-7. For the calculation of the annual production increase, the annual revenues and the intervention cost savings due to a reduced number of interventions per year the same procedure has been applied as for the best case. The only difference is that every year just 500 wells which are equipped with inhibitor treatment pumps are affected by the intervention frequency decrease.

The annual production increase, the annual revenues and the intervention cost savings have been calculated separately for the 500 wells which are equipped in each of the five years and then for the 5,079 wells which are not equipped with inhibitor treatment pumps. At the end of the revenue calculations for the worst case, all the separately calculated production increases, revenues and intervention cost savings have again been summed up. These sums are the total production increase, the total annual revenues and the total number of intervention cost savings for the worst case.

Tab. 5-17 represents the calculation table of the annual production increase, the annual revenues and the annual savings due to the reduced number of interventions for the 500 wells which are equipped in the first year. The structure of the calculation table is the same as for the best case. The input data for the calculation is also the same except for the number of wells equipped with pumps in the first year.

Tab. 5-17 Annual production increase, annual revenues and annual intervention cost savings of the 500 wells equipped with inhibitor treatment pumps in the first year

Inhibitor (Worst case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	500	wells:				
Intervention costs/well/year [Euro/year]:		17.033,70 €	11.355,85 €	11.355,85 €	9.084,68 €	9.084,68 €
Total intervention costs/year (new) [Euro/year]:		8.516.887,50 €	5.677.925,00 €	5.677.925,00 €	4.542.340,00 €	4.542.340,00 €
Total intervention costs/year (old) [Euro/year]:		11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	11.355.850,00 €
Production losses/well/year [tons/year]:		81,69	49,01	44,11	31,76	28,59
Total production losses/year [tons/year]:		40.845,85	24.507,39	22.056,65	15.880,78	14.292,71
Total production losses/year [bbl/year]:		299.398,58	179.639,15	161.675,24	116.406,17	104.765,55
Total oil production/year (old) [tons/year]:		218.441,92	196.597,72	176.937,95	159.244,16	143.319,74
Total oil production/year (old) [bbl/year]:		1.601.179,25	1.441.061,37	1.296.955,19	1.167.259,67	1.050.533,70
Production increase/year [bbl/year]:		99.799,53	179.639,15	161.675,24	174.609,25	157.148,33
Total oil production/year (new) [bbl/year]:		1.700.978,77	1.620.700,47	1.458.630,42	1.341.868,92	1.207.682,03
Revenues / year [Euro/year]:		78.544.044,81	72.931.521,23	65.638.369,10	60.384.101,80	54.345.691,44
Savings due to reduced interventions/year [Euro/year]:		2.838.962,50 €	5.677.925,00 €	5.677.925,00 €	6.813.510,00 €	6.813.510,00 €

Then the same calculations follow for the 500 wells which have been carried out in the best case for the 2,500 wells equipped in the first year.

These calculations for the first year of the calculation model include the:

- **annual intervention costs per well**
- **annual intervention costs for 7.5 interventions per well for all the 500 wells**
- **annual intervention costs for 10 interventions per well for all the 500 wells**
- **annual savings due to the reduced number of interventions**
- **annual production losses per well**
- **annual production losses of the 500 wells**
- **annual oil production of the 500 wells**
- **annual oil production of the old scenario**
- **annual production increase**
- **annual revenue.**

They have again been calculated in the same manner as for the best case, which was described in detail in the last chapter, but for 500 wells per year instead of 2,500 in the first and in the second year.

Tab. 5-18 displays the calculation table of the production increases, the annual revenues and the savings due to the reduced number of interventions for the 500 wells which are equipped in the second year. By observing this table, it can be seen again that the total intervention costs per year do not decrease in the first year, because no inhibitor pumps are installed and therefore the number of interventions per well still remains at 10. Consequently there are no savings due to reduced interventions and no production increase for these 500 wells in the first year.

Tab. 5-18 Annual revenues and annual intervention cost savings of the 500 wells equipped with inhibitor treatment pumps in the second year

Inhibitor (Worst case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	500	wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	17.033,78 €	11.355,85 €	11.355,85 €	9.084,68 €
Total intervention costs/year (new) [Euro/year]:		11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	11.355.850,00 €
Total intervention costs/year (old) [Euro/year]:		11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	11.355.850,00 €
Production losses/well/year [tons/year]:		108,92	73,52	44,11	39,70	28,59
Total production losses/year [tons/year]:		54.460,08	36.761,00	22.056,65	19.850,98	14.292,71
Total production losses/year [bbl/year]:		399.190,11	269.458,73	161.675,24	145.507,71	104.765,55
Total oil production/year (old) [tons/year]:		218.441,92	196.597,72	176.937,95	159.244,16	143.319,74
Total oil production/year (old) [bbl/year]:		1.601.179,25	1.441.061,32	1.296.955,19	1.167.259,67	1.050.533,70
Production increase/year [bbl/year]:		0,00	89.019,58	161.675,24	145.507,71	157.148,33
Total oil production/year (new) [bbl/year]:		1.601.179,25	1.530.080,90	1.458.630,42	1.312.767,38	1.207.682,03
Revenues / year [Euro/year]:		72.053.066,04 €	68.853.640,33 €	65.638.369,10 €	59.074.532,19 €	54.345.691,44 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	- €

The tables for the 500 pumps which are installed in the third, the fourth and the fifth year again have the same structure. For the wells which are equipped in the third year the annual intervention frequency per well stays at 10 until the third year. Consequently the intervention frequency per well for the wells which are equipped in the fourth and fifth year stays at 10 until they are equipped with pumps. So these wells show again no savings and production increase until the point at which the installation of the inhibitor treatment pumps takes place. In the case of the 5,079 wells which are not equipped with pumps the annual intervention frequency per well always remains at 10 and no savings and production increase are realized with these wells. The tables concerning the wells which are equipped in the third, fourth and fifth year and the wells which are not equipped with pumps are shown on Tab. 10-1, Tab. 10-2, Tab. 10-3 and Tab. 10-4 in the Appendix.

After the calculations of the **annual oil production**, the **annual revenues generated by the production** and the **annual savings due to the reduced interventions per year** for the 500 wells which are equipped every year and the 5,079 which are not equipped, the results have been summed up again to get the **annual production,** the **annual revenues** and the **annual savings** for all of the 7,579 sucker rod pumped wells. These sums are represented on Tab. 5-19.

Tab. 5-19 Annual production, annual revenues and annual intervention cost savings of all 7,579 sucker rod pumped wells in the best case

Inhibitor (Worst case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	7.579	wells				
Total oil production/year (new) [bbl/year]:		24.370.474,53	22.113.066,23	20.063.434,84	18.231.700,81	16.565.678,88
Revenues / year [Euro/year]:		1.096.671.353,77 €	995.087.980,19 €	902.854.567,78 €	820.426.537,47 €	745.455.549,34 €
Savings due to reduced interventions/year[Euro/year]:		2.838.962,50 €	5.677.925,00 €	8.516.887,50 €	15.330.397,50 €	21.008.322,50 €

In the worst case the annual oil productions and annual revenues generated by the production are also higher than on Tab. 5-5, which displays the annual oil productions for an intervention frequency of 10 interventions per year. But it is, of course, not as high as in the best case, because in the worst case the production decline was also reduced but not as strongly as in the best case. The savings due to a reduced number of interventions are also lower than in the best case, because a lower number of wells have been affected by the intervention frequency decrease.

5.3.4 Production increase and intervention cost savings for the realistic case

In the most realistic case 5,000 inhibitor treatment pumps are installed in the first three years of the calculation model. 1,000 of the inhibitor treatment pumps are installed in the first year, 2,000 in second year and 1,000 of them are installed in the third year. According to experts, this pump installation scenario is the most likely one to be realized due to logistical aspects. The assumed development of the intervention frequencies due to corrosion inhibitor employment in the most realistic case is displayed on Tab. 5-8. To calculate the annual revenues and the intervention cost savings due to a reduced number of interventions per year, the same procedure has been applied as for the best case. The difference is again the number of installed inhibitor treatment pumps per year and consequently the wells that are affected by the reduced intervention frequency per year.

The annual production increase, the annual revenues and the intervention cost savings have again been calculated separately for the 1,000 wells which are equipped in the first year, the 2,000 pumps equipped in the second year, the 2,000 pumps equipped in the third year and then for the 5,079 wells which are not equipped with inhibitor treatment pumps. Afterwards the annual revenues generated by the production and the annual savings due to the reduced number of interventions per year have been calculated by summing up the separately calculated revenues and the intervention cost savings.

On Tab. 5-20 the calculation of the annual production increase, the annual revenues and the annual savings due to the reduced number of interventions for the 1,000 wells which are equipped in the first year is displayed. The structure of the calculation table and the input data for the calculation is, except of the number of equipped wells, again the same as for the best case.

Tab. 5-20 Annual production increase, annual revenues and annual intervention cost savings of the 1,000 wells equipped with inhibitor treatment pumps in the first year.

Inhibitor (Most realisitic case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	1.000	wells				
Intervention costs/well/year [Euro/year]:		17.033,78 €	11.355,85 €	11.355,85 €	9.084,68 €	9.084,68 €
Total intervention costs/year (new) [Euro/year]:		17.033.775,00 €	11.355.850,00 €	11.355.850,00 €	9.084.680,00 €	9.084.680,00 €
Total intervention costs/year (old) [Euro/year]:		22.711.700,00 €	22.711.700,00 €	22.711.700,00 €	22.711.700,00 €	22.711.700,00 €
Production losses/well/year [tons/year]:		81,69	49,01	44,11	31,76	28,59
Total production losses/year [tons/year]:		81.691,29	49.014,78	44.113,30	31.761,57	28.585,42
Total production losses/year [bbl/year]:		598.797,17	359.278,30	323.350,47	232.812,34	209.531,11
Total oil production/year (old) [tons/year]:		436.883,83	393.195,45	353.875,90	318.488,31	286.639,48
Total oil production/year (old) [bbl/year]:		3.202.358,49	2.882.122,64	2.593.910,38	2.334.519,34	2.101.067,41
Production increase/year [bbl/year]:		199.599,06	359.278,30	323.350,47	349.218,51	314.296,66
Total oil production/year (new) [bbl/year]:		3.401.957,55	3.241.400,94	2.917.260,85	2.683.737,85	2.415.364,08
Revenues / year [Euro/year]:		153.088.089,62	145.863.042,45	131.276.738,21	120.768.203,21	108.691.382,89
Savings due to reduced interventions/year[Euro/year]:		5.677.925,00	11.355.850,00	11.355.850,00	13.627.020,00	13.627.020,00

Then, calculations have been carried out to evaluate the data on Tab. 5-20. They have been calculated in the same manner as for the best case and the worst case, which was described in detail in the last two chapters, but again for a different number of equipped wells per year.

Tab. 5-21 shows the calculation table of the annual revenues and the savings due to the reduced number of interventions for the 2,000 wells equipped in the second year. As for the best and the worst case it can be observed again that the total intervention costs per year do not decrease in the first year, because again no inhibitor treatment pumps are installed and therefore the number of interventions per well still remains at 10. Consequently there are also for the most realistic case no savings due to reduced interventions and no production increase for these 2,000 wells in the first year.

Tab. 5-21 Annual production increase, annual revenues and annual intervention cost savings of the 2,000 wells equipped with inhibitor treatment pumps in the second year.

Inhibitor (Most realisitic case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	2.000	wells				
Intervention costs/well/year [Euro/year]:		22.711,70 €	17.033,78 €	11.355,85 €	11.355,85 €	9.084,68 €
Total intervention costs/year (new) [Euro/year]:		45.423.400,00 €	34.067.550,00 €	22.711.700,00 €	22.711.700,00 €	18.169.360,00 €
Total intervention costs/year (old) [Euro/year]:		45.423.400,00 €	45.423.400,00 €	45.423.400,00 €	45.423.400,00 €	45.423.400,00 €
Production losses/well/year [tons/year]:		108,92	73,52	44,11	39,70	28,59
Total production losses/year [tons/year]:		217.843,45	147.044,33	88.226,60	79.403,94	57.170,83
Total production losses/year [bbl/year]:		1.598.792,45	1.077.834,91	646.700,94	582.030,85	419.062,21
Total oil production/year (old) [tons/year]:		873.767,88	786.390,90	707.751,81	636.976,63	573.278,96
Total oil production/year (old) [bbl/year]:		6.404.718,08	5.764.245,28	5.187.820,75	4.669.038,68	4.202.134,81
Production increase/year [bbl/year]:		0,00	359.278,30	646.700,94	582.030,85	628.593,32
Total oil production/year (new) [bbl/year]:		6.404.718,08	6.123.523,58	5.834.521,70	5.251.069,53	4.830.728,13
Revenues / year [Euro/year]:		288.212.284,15	275.558.561,37	262.553.476,42	236.298.128,77	217.382.765,77
Savings due to reduced interventions/year[Euro/year]:		- €	11.355.850,00 €	22.711.700,00 €	22.711.700,00 €	27.254.040,00 €

The table for the 2,000 wells which are equipped in the third year is characterized by the same structure. For these wells, the annual intervention frequency per well stays at 10 until the installation takes place. For this reason these wells show again no savings and production increase until the third year. For the 5,079 wells which are not equipped with pumps the annual intervention frequency per well always stays at 10 and again no savings and no production increase are realized with these wells. The tables for the wells which are equipped in the third year with pumps and for the 2,579 wells which are not equipped with pumps are shown on Tab. 10-5 and Tab. 10-6 in the Appendix.

After the separate calculations of the annual oil production increase, the resulting annual oil production, the annual revenues generated by the production and the annual savings due to the reduced interventions per year for the 1,000 wells equipped in the first year, the 2,000 wells equipped in the second year, the 2,000 wells equipped in the third year and the 5,079 which are not equipped, the results have been summed up again to get the annual production, the annual revenues and the annual savings for all of the 7,579 sucker rod pumped wells. These figures are shown on Tab. 5-22.

Tab. 5-22 Annual production, annual revenues and annual intervention cost savings of all 7579 sucker rod pumped wells in the most realistic case

Inhibitor (Most realisitic case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	7.579	wells				
Total oil production/year (new) [bbl/year]:		24.470.274,06	22.562.184,10	20.952.848,84	19.206.602,28	17.390.707,61
Revenues / year [Euro/year]:		1.101.162.332,55 €	1.015.297.384,67 €	942.869.188,66 €	864.297.102,71 €	782.581.842,32 €
Savings due to reduced interventions/year[Euro/year]:		5.677.925,00 €	22.711.700,00 €	45.423.400,00 €	59.050.420,00 €	63.592.760,00 €

As for the best and for the worst cases it can be observed again that the annual oil production and revenues generated by the production are higher than on Tab. 5-5, which shows the annual oil productions with an intervention frequency of 10 interventions per year. In this case the production decline of 10% has also been reduced. The reduction of this decline is higher than in the worst case, but lower than in the best one. For this reason also, the annual oil production, the annual revenues and the savings lie between the values of the best and the worst case.

The total annual oil productions and the annual production increase due to the employment of corrosion inhibitors - in absolute numbers and in percent - are displayed on Fig. 10-1, Fig. 10-2 and Fig. 10-3 in the Appendix.

5.3.5 Differences in net present value for the best, worst and realistic cases

As already described in a preceding chapter, the net present value is calculated as the sum of the annual discounted cash flows. The cumulated savings due to the employment of a corrosion inhibitor have been computed by calculating the difference of the net present value assuming 10 interventions per year and the net present value assuming a reduced number of interventions. These total savings are the differences in the net present values and must not be mistaken with the savings due a reduced number of interventions, which have been necessary to calculate the total savings. The annual cash flows assuming a reduced number of interventions have been evaluated according to the following procedure:

Annual revenues (generated by the oil production)

\+ Annual savings (due to reduced interventions)

\- Annual capex

\- Annual opex

= Annual cash flows

Then, the annual cash flows for the scenario which considers no employment of corrosion inhibitor and therefore no reduction of the actual intervention frequency of ten interventions per year per well have been evaluated. For this scenario, no annual savings due to a reduced number of interventions are realized, but also no additional investment costs have to be expended. For this reason, the annual revenues equal the annual cash flows. For the best case, the calculation of the difference in net present value is shown on Tab. 5-23. The calculation tables of the worst and the most realistic cases are represented on Tab. 10-7 and Tab. 10-8 in the Appendix.

Tab. 5-23 Difference in the net present value for the best case

Inhibitor (Best case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Annual revenues due to the oil production [Euro/year]:	1.213.533.750,00	1.114.635.208,87 €	1.043.590.550,94 €	957.419.950,88 €	868.225.810,95 €	787.296.292,20 €
Annual savings due to reduced interventions [Euro/year]:		14.194.812,50 €	42.584.437,50 €	56.779.250,00 €	62.457.175,00 €	68.135.100,00 €
Annual capex [Euro/year]:	12.500.000,00	12.500.000,00 €	- €	- €	- €	
Annual opex [Euro/year]:		2.046.938,43 €	3.456.326,12 €	3.360.603,51 €	3.274.624,16 €	3.197.161,74 €
Annual cash flow(Best case)[Euro/year]:	1.201.033.750,00 €	1.114.283.142,93 €	1.082.718.662,32 €	1.010.838.516,37 €	927.408.361,79 €	852.234.230,46 €
Annual discounted cash flow(10interventions/year)[Euro/year]:	1.213.533.750,00 €	983.946.283,78 €	797.794.284,15 €	646.860.230,39 €	524.481.267,88 €	425.255.082,07 €
Annual discounted cash flow(Best case)[Euro/year]:		1.003.858.687,33 €	878.758.755,73 €	739.116.411,08 €	610.912.613,59 €	505.759.535,88 €
Net present value (10 interventions per year)[Euro/year]:		2.197.480.033,78 €	2.995.274.317,93 €	3.642.134.548,32 €	4.166.615.816,21 €	4.591.870.898,28 €
Net present value (Best case)[Euro/year]:		2.204.892.437,33 €	3.083.651.192,56 €	3.822.767.603,62 €	4.433.680.217,21 €	4.939.439.753,09 €
Difference in net present value [Euro/year]:	- 12.500.000,00 €	7.412.403,54 €	88.376.874,63 €	180.633.055,30 €	267.064.401,00 €	347.568.854,82 €

In the first row of the table, the five years of the calculation model and the year before the first installation are shown. The first column shows the necessary data to calculate the difference in net present value or total savings. At first the annual cash flows for the best case and for the case without the employment of corrosion inhibitor have been calculated as already explained above.

Then these cash flows have been discounted to consider the time value of money. The discounted cash flows have been evaluated by using the following formula:

$$Discounted\ CF = CF * (1+i)^{-t}$$

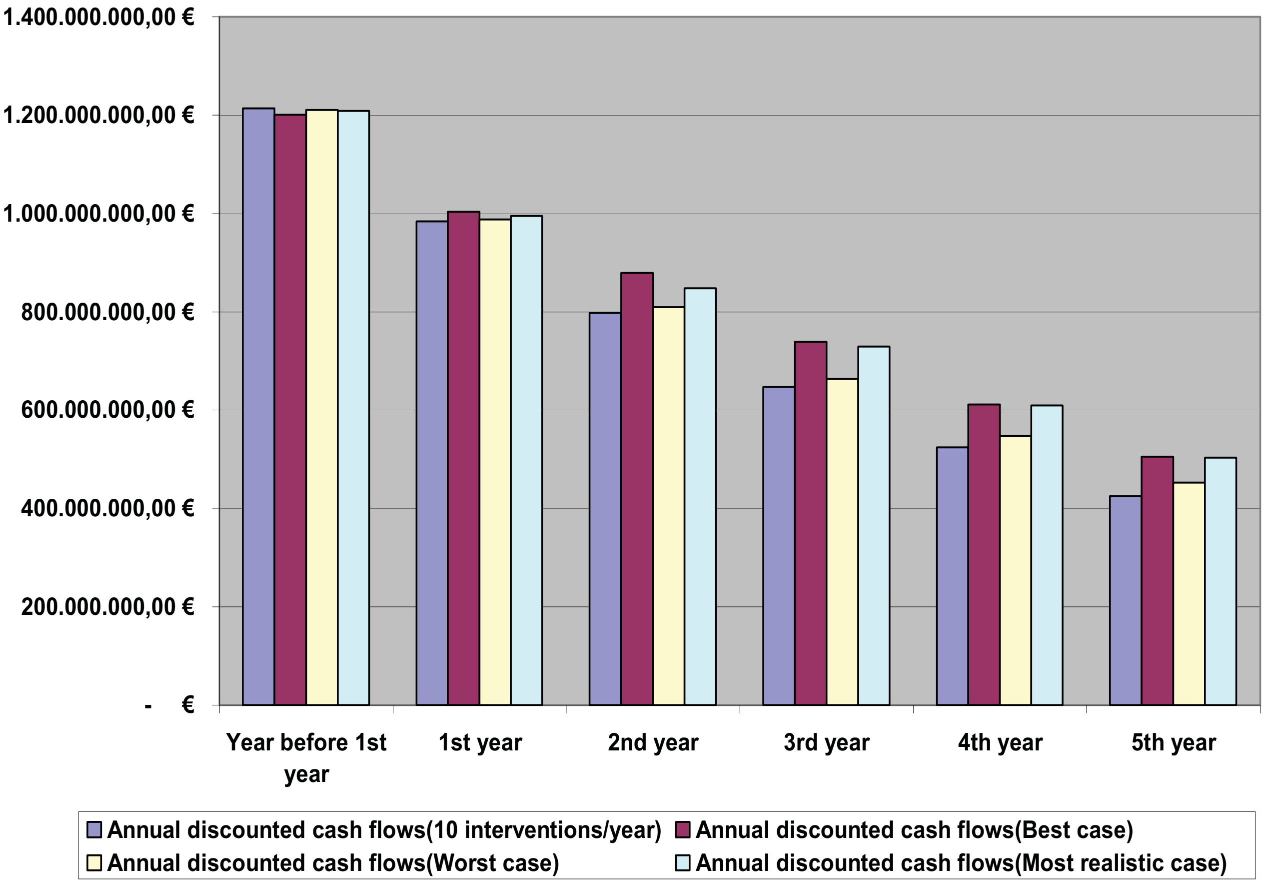
$$CF = cash\ \ flow$$

$$i = imputed\ interest\ rate$$

$$t = time\ index$$

According to experts the imputed interest rate which is used for net present value calculations at OMV is 11%. For this reason the calculated cash flows have then been discounted with 11% per year. The discounted cash flows for the best, worst, most realistic case and the case without any changes are represented on Fig. 5-2.

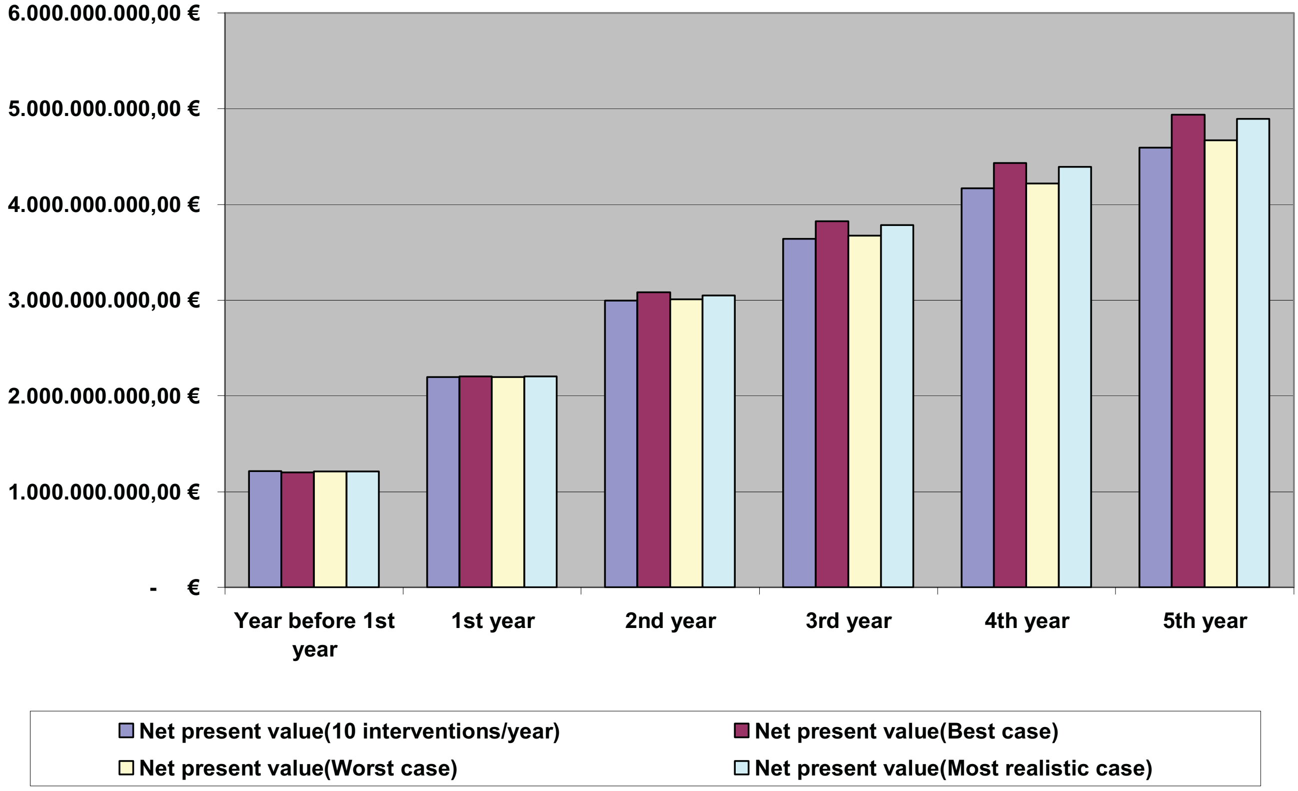
Fig. 5-2 Discounted cash flows for different corrosion inhibitor scenarios



As can be observed on the diagram, the discounted cash flow in the best case is significantly higher than in the most realistic case until the second year. But then the discounted cash flow of the most realistic case increasingly approaches the discounted cash flow of the best case. The reason for this development is quicker installation of the inhibitor treatment pumps in the best case. But in both cases 5,000 pumps are installed and so after five years the discounted cash flows are almost the same.

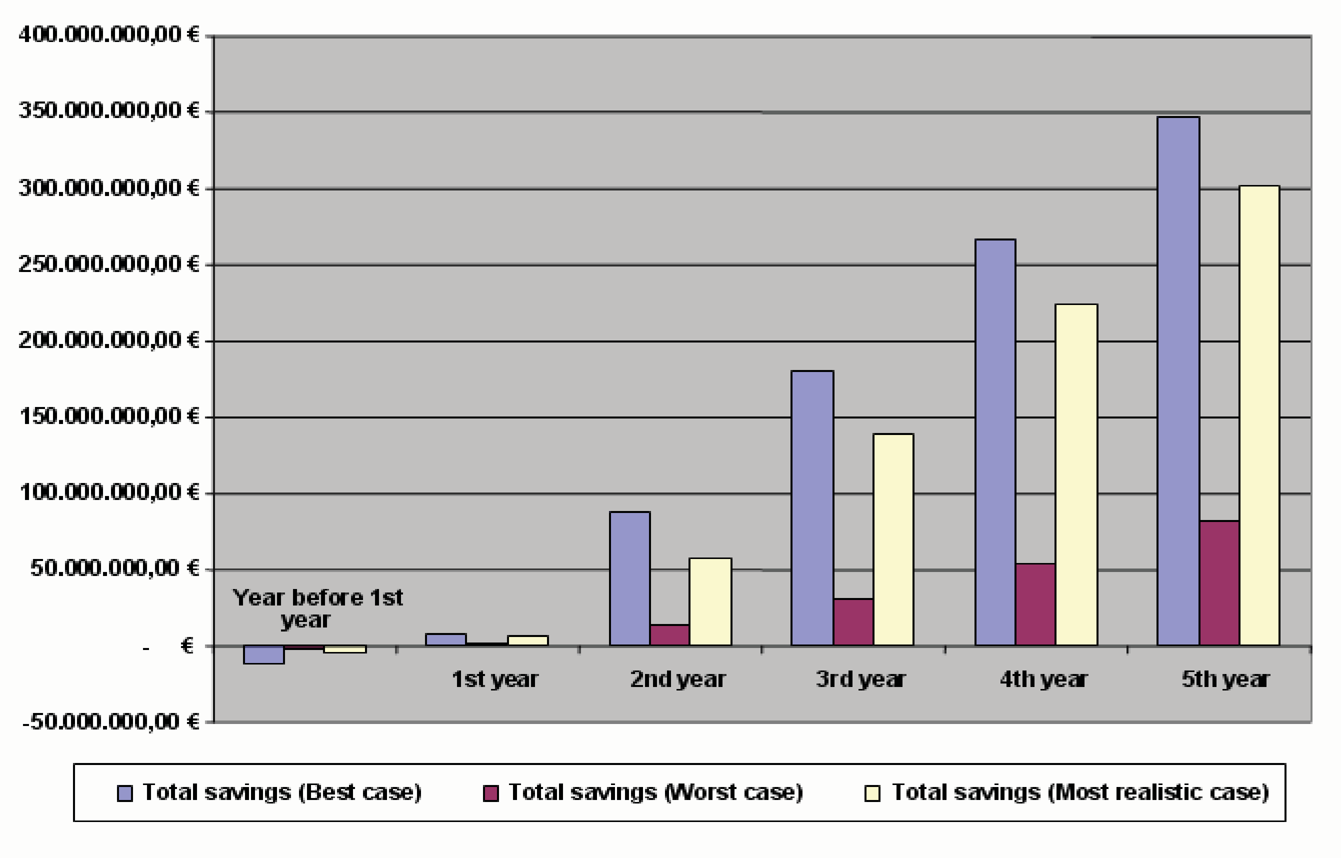
After that the net present values for the best case and for the case without any changes, which is characterized by an intervention frequency of 10, have been calculated as the sum of the discounted cash flows. These net present values are shown on Fig. 5-3.

Fig. 5-3 Net present values for different corrosion inhibitor scenarios



Finally, the total savings have been evaluated as the difference of these net present values. One interesting aspect that must be mentioned is that the difference in the net present value in the year of the first investment, which is the year before the first installation, coincides exactly with the annual capex. The reason for this is that in this year just the investment for the inhibitor treatment pumps is made, but no installation takes place. Therefore, no reduction of the intervention frequency and no savings are realized in this year. Additionally, no discounting takes place in this year, and so the difference of the net present values corresponds with the capex. These total savings or differences of the net present values are displayed on Fig. 5-4. As can be seen on the chart the savings in the best case and in the most realistic case are significantly higher than in the worst case. The payout period is 1.22 years in the best case, 1.38 years in the worst case and 1.2 years in the most realistic case.

Fig. 5-4 Total savings for different corrosion inhibitor scenarios



5.4 Tubing string

At first, three tables which show the assumed development of the reduced intervention frequencies were created again to estimate the total savings and the production increase due to the employment of new tubing string material. They have been created for the best, the worst and the most realistic case scenario. Currently, about 10% of the tubing material is exchanged. This number has been estimated by reconstructing the following scenario.

If a tubing failure occurs, an intervention is carried out, with the purpose of exchanging just the broken part. That means that in the majority of the interventions, just one single tubing part is exchanged. The average depth of a well in Romania has been assumed with 1,000 meters and the length of a tubing part is approximately ten meters. Consequently every well includes about one hundred single tubings. At the moment the annual intervention frequency in Romania is 10 interventions per well per year. For this reason 10 single tubings are exchanged per well per year by doing ten interventions per well per year. These 10 single tubings are 10% of the 100 single tubings in a well. Based on this scenario it has been assumed that about 10% of the tubing material is replaced in Romania every year. Or in other words it was estimated that 10% of all wells are equipped with new tubing material every year.

Concerning the best case of new tubing material employment the actual 10% are still replaced, additionally 15% are installed in the first three years and then 20% are additionally installed in the following years of the calculation model. But the manner of installation is different. The 10% are replaced by exchanging the broken tubings piecewise and the additionally 15% and after the third year 20% are replaced by exchanging the complete tubing string. The sum of exchanged tubing material is always about 25% per year. The reason for this is that the 10%, which are exchanged as is standard at the moment in Romania always refers to wells with old tubing material, because a completely exchanged well will never need 10 interventions per year. A certain percentage of wells are completely exchanged every year, and so the number of wells with old tubing material is decreasing from year to year. Therefore, the 10% refers to a smaller number of wells from year to year, and so 10% of the not yet completed wells are exchanged. That is to say that compared to the total amount of tubing material, these wells represent, for example, just 7% in the third year, because the number of wells with old material is decreasing. This is the reason why the percentage of completely exchanged wells can be increased after the third year. By doing this, the whole percentage of exchanged wells approaches again 25%, otherwise it would decrease.

The tubing material which is installed by exchanging the complete tubing string is additionally equipped with thermoplastic tubular liners to increase their durability. Concerning the old material a wall thickness survey is carried out. As already explained the reason for this wall thickness survey is to identify the tubings in the well, which can still be used and therefore be installed in other wells. That means that for the calculation model just new tubing material has been used to replace the old, because no one is able to predict the number of tubings which can still be used. Tab. 5-24 displays the development of the assumed reduced intervention frequency for the certain percentage of wells which are completely exchanged with new tubing material every year. The first row of the table shows the years of the calculation model and the first column represents the annually installed inhibitor treatment pumps.

Tab. 5-24 Development of the intervention frequencies due to new tubing material employment in the best case

Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
15,00%	6	3	3	2	2
15,00%	10	6	3	3	2
15,00%	10	10	6	3	3
20,00%	10	10	10	6	3
20,00%	10	10	10	10	6
15,00%	10	10	10	10	10

For the 15% of the wells which are completely equipped with new tubing material, an intervention frequency of 6 interventions per well per year is assumed in the first year of installation. It goes without saying that not all wells can be equipped simultaneously, and so the assumed intervention frequency in the first year is higher than in the following years. The other 85% of the wells are not affected by the installation of the new tubing material in the first year, and so their intervention frequency still stays at 10 interventions per well per year as it can be observed in the second column of the table. Concerning the wells which are equipped with new tubing material in the first year, the intervention frequency decreases to 3 interventions per well per year in the second year and to 2 interventions per well per year in the fourth year. Due to the fact that the tubing material is additionally equipped with thermoplastic tubular liners, the intervention frequency decrease has been assumed more strongly than for the other planned actions. This development in the intervention frequencies can be seen in the second row of the table.

Another 15% of the wells are completely equipped with new material in the second year which reduces the intervention frequency of these wells to 3 in the second year. The frequency of interventions for these wells has the same development like the intervention frequency of the first 15% of the wells which has been equipped in the first year, but with a delay of one year. This fact can be observed in the third row of the table.

Other wells which are equipped later with the new tubing material show the same development in the intervention frequency, but with a delay of for example two years if the new tubing material is installed in the third year or with a delay of four years if it is in the fifth year, as it is displayed on Tab. 5-24. The number of interventions per well per year remains at 10 until the year of installation. In the best case 15% of the wells are not equipped with new tubing material and so their intervention frequency always remains at 10%.

In the most realistic case 10% are again installed as has been standard in Romania until now. Moreover 10% are installed by exchanging complete tubing strings in the first three years and an additional 15% are installed by exchanging complete tubing strings in the fourth and fifth years. The reason for the increase of the percentage of wells which are completely exchanged with new tubing material is the same as in the best case. Altogether about 20% of the tubing material is exchanged every year.

Tab. 5-25 Development of the intervention frequencies due to new tubing material employment in the most realistic case

Percentage of wells	1styear	2ndyear	3rdyear	4thyear	5thyear
10,00%	6	3	3	2	2
10,00%	10	6	3	3	2
10,00%	10	10	6	3	3
15,00%	10	10	10	6	3
15,00%	10	10	10	10	6
40,00%	10	10	10	10	10

The development of the assumed reduced intervention frequency for the most realistic case is shown on Tab. 5-25. The first row of the table shows again the years of the calculation model and the first column represents the percentage of annually equipped wells. The development of the intervention frequencies is the same as for the best case, but with the difference that a lower number of wells are affected by this intervention frequency decrease. In the most realistic case, 40% of the wells are not equipped with new tubing material as it can be observed on Tab. 5-25. The intervention frequency of these wells always stays at 10.

In the worst case, 5% of the wells are equipped with new tubing material per year in the first three years, 7% percent are equipped in the fourth and in the fifth year 10% of the wells are again equipped as it has been standard in Romania until now. In this case this 10% refer again to the wells which have not already been completely exchanged. But the number of wells including old material is decreasing from to year to year, and so, in reality, this percentage of 10% refers to a lower number of wells every year. For this reason the wells which are completely exchanged with new tubing material are again increased after the third year to maintain an average annual exchange rate of 15% per year. The development of the intervention frequencies for the completely exchanged wells is displayed on Tab. 5-26.

Tab. 5-26 Developing of the intervention frequencies due to new tubing material employment in the worst case

Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
5,00%	6	3	3	2	2
5,00%	10	6	3	3	2
5,00%	10	10	6	3	3
7,00%	10	10	10	6	3
7,00%	10	10	10	10	6
71,00%	10	10	10	10	10

The structure of the table for the worst case is exactly the same one as for the two preceding tables. The difference is again the percentage of wells which are equipped with new tubing material every year, and so the percentage of wells which is affected by the intervention decrease. Concerning the worst case, 71% of the wells are not equipped with new tubing material as can be observed on Tab. 5-26. The intervention frequency of these wells again remains at 10%.

Based on these assumed intervention frequencies the calculations of the costs for the new tubing material and the estimates of the total savings due to the employment of new tubing material have been carried out.

5.4.1 Costs of the new tubing material

The required data to calculate the costs for the new tubing material are the price of the J-55 steel tubing, the price for the inspection of the material, the price for the wall thickness survey and the price for the lined tubing process. Other important data for the cost calculations are the number of sucker rod pumped wells in Romania, the length of a tubing and the average number of tubings in a well. All these data are based on the advice of experts from OMV. These data are listed on the Tab. 5-27.

Tab. 5-27 Necessary data for the tubing material costs calculation

J-55 steel tubing price	18.5	[Euro/meter]
Inspection price	0.1	[Euro/tubing]
Wall thickness survey price	3	[Euro/meter]
Lining process price	4.95	[Euro/meter]
Number of sucker rod pumped wells	7,579	[ ]
Length of a tubing	10	[meter]
Average number of tubings per well	100	[ ]

Tab. 5-28 Calculation of the total annual tubing costs for the best case

Tubing costs (Best case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
10% of the not already completely exchanged wells are exchanged as Standard:		10%	10%	10%	10%	10%
Annual tubing material costs [Euro/year]:	14.021.150,00 €	11.917.977,50 €	9.814.805,00 €	7.711.632,50 €	4.907.402,50 €	2.103.172,50 €
Additional annual exchange rate		15,00%	15,00%	15,00%	20,00%	20,00%
Annual tubing material costs [Euro/year]:	21.043.093,50 €	21.043.093,50 €	21.043.093,50 €	28.057.458,00 €	28.057.458,00 €	28.057.458,00 €
Annual lining process costs [Euro/year]:	5.631.045,42 €	5.631.045,42 €	5.631.045,42 €	7.508.060,56 €	7.508.060,56 €	7.508.060,56 €
Annual wall thickness survey costs [Euro/year]:		3.410.550,00 €	3.410.550,00 €	3.410.550,00 €	4.547.400,00 €	4.547.400,00 €
Total annual exchange rate:		25,00%	23,50%	22,00%	25,50%	23,50%
Total annual tubing costs [Euro/year]:	35.064.243,50 €	42.002.666,42 €	39.899.493,92 €	46.687.701,06 €	45.020.321,06 €	42.216.091,06 €

Tab. 5-28 represents the calculation of the tubing costs for the best case. The first row shows the years of the calculation model and the first column shows the terms for the different parts of the tubing costs. These are:

- **the annual tubing material costs of the 10% of tubing material which is exchanged as has been standard in Romania until now,**
- **the annual tubing material costs for the additional percentage of tubing material,**
- **the annual lining process costs and**
- **the annual wall thickness survey costs.**

In the calculation model, all these materials are bought in the year before the installation takes place, and so their costs are also realized in the year before the installation. They are the so-called capex of the total tubing costs. The only exception is the costs for the wall thickness survey, because they are realized in the year of the installation. They build the so-called opex of the total tubing costs. The sum of these is the **total annual tubing costs**.

At first, the **annual tubing material costs of the 10 %** of tubing material which is exchanged as has been standard in Romania until now has been evaluated. As already mentioned this 10% refer to the wells which have not already been completely exchanged. That means that in the first year these are exactly 10% of the whole tubing material in the sucker rod pumped wells. But in the following years, this exchanged tubing material is decreasing, because of the decreasing number of wells which still contain old material. The **annual costs for this 10%** for the first year has been calculated as the product of

- **the number of sucker rod pumped wells in Romania,**
- **the price of one tubing**
- **the average number of tubings per well**
- **and the exchange percentage of 10%.**

For the year before the first installation all the sucker rod pumped wells have been taken into account for this calculation, because in the first year all these wells are still equipped with old material. For the following years the calculation was adapted to consider the annually decreasing number of wells which still include old material. Therefore, to calculate the costs for the other years the result of the year, before the first installation has been multiplied by the percentage of wells which has not been completely exchanged until the respective year. That means that the result of the year before the first installation has been multiplied by, for example 0.85, to calculate the costs for the tubing material which is supposed to be exchanged in the second year. The reason for this is that after the first year only 85% of the sucker rod pumped wells include old material, because 15% have been exchanged in the first year. As already mentioned, all these materials are bought in the year before the installation takes place, and so the costs in the first year refer the tubing material which is installed in the second year. For the following years the costs have been estimated according to the same procedure. That means that, for example, the costs of the material in the second year, which is supposed to be installed in the third year, have been multiplied by 0.7, because after the second year 30 percent of the wells have been completely exchanged. The results of this calculation are shown in the third row of table Tab. 5-28.

The next step was the calculation of the **annual tubing material costs for the additional percentage of tubing material** per year. These costs have been calculated as the sum of the costs for the tubing material and the inspection price, because the new tubing material should be inspected before it is installed. But compared to the price of tubing, the inspection price is very low as it can be seen on Tab. 5-27. As already explained, the tubings which are installed in the first year are bought in the year before the first year of installation. These tubing costs for the year before the first year of installation have been calculated by multiplying 15%, which is the exchange rate in the first year, by the number of sucker rod pumped wells and multiplied by the price for 100 tubings, which is the average number of tubings in a well. The inspection costs for the for the year before the first year of installation have been calculated by multiplying 15% by the number of sucker rod pumped wells and then multiplying this product by the inspection price for 100 tubings.

The **annual tubing material costs for the additional percentage of tubing material** have then been calculated as the sum of these. The results of this calculation are shown in the sixth row of Tab. 5-28. For the following years these costs have been calculated according to the same procedure. The percentage of the wells which are completely exchanged is increased in the fourth year as it has already been described in the preceding chapter. This can also be seen in the fourth row of the table.

As already mentioned the new tubing material is also equipped with thermoplastic tubular liners to increase their durability. The **lining procedure costs** for the first year have been calculated by multiplying 15%, which is again the exchange rate, by the number of sucker rod pumped wells and again by the lining procedure costs for the average number of 100 tubings in a well. For the following years these costs have again been calculated according to the same procedure and the percentage of the wells which are completely exchanged is again increased in the fourth year. The results of this calculation are displayed in the sixth row of Tab. 5-28.

Afterwards the **annual wall thickness survey costs** have been calculated. These costs are realized in the year of the installation, and so there are no wall thickness survey costs before the year of the first calculation. The wall thickness survey costs for the first year have been calculated by multiplying 15% by the number of sucker rod pumped wells and by the inspection price for 100 tubings. The percentage of the wells which are completely exchanged is increased again in the third year. These costs are shown in the seventh row of Tab. 5-28.

To compare the annual exchanged tubing material, **the total annual exchange rate** has been calculated. For the year before the first year of installation, this is just the sum of 10% and the additional installed 15%, which equals 25%. For the other years the total annual exchange rate has been calculated by multiplying 10% by the percentage of wells which has not been completely exchanged until the respective year and adding to this product 15%. For the first year of installation, for example, this is 10% multiplied by 85%, which is the percentage of not completely exchanged wells, plus 15%. The result is the total annual exchange rate of new tubing material in the second year, which has to be bought in the first year of the calculation model. As can be observed in the table this percentage annually decreases. For this reason the percentage of the wells which are completely exchanged is increased in the fourth year. The reason for this increase has already been described in detail.

At the end, the **total annual tubing costs** have been calculated as the sum of different parts of the tubing costs. These are shown in the last row of the table.

The total tubing costs for the worst and the most realistic cases have been calculated in the same manner. The significant difference in the calculations was the percentage of equipped wells per year, as it can be seen in the fourth row of Tab. 5-29 and Tab. 5-30.

Tab. 5-29 Calculation of the total annual tubing costs for the most realistic case

Tubing costs (Most realistic case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
10% of the not already completely exchanged wells are exchanged as Standard:		10%	10%	10%	10%	10%
Annual tubing material costs [Euro/year]:	14.021.150,00 €	12.619.035,00 €	11.216.920,00 €	9.814.805,00 €	7.711.632,50 €	5.608.460,00 €
Additional annual exchange rate		10,00%	10,00%	10,00%	15,00%	15,00%
Annual tubing material costs [Euro/year]:	14.028.729,00 €	14.028.729,00 €	14.028.729,00 €	21.043.093,50 €	21.043.093,50 €	21.043.093,50 €
Annual lining process costs [Euro/year]:	3.754.030,28 €	3.754.030,28 €	3.754.030,28 €	5.631.045,42 €	5.631.045,42 €	5.631.045,42 €
Annual wall thickness survey costs [Euro/year]:		2.273.700,00 €	2.273.700,00 €	2.273.700,00 €	3.410.550,00 €	3.410.550,00 €
Total annual exchange rate:		20,00%	19,00%	18,00%	22,00%	20,50%
Total annual tubing costs [Euro/year]:	31.803.909,28 €	32.675.494,28 €	31.273.379,28 €	38.762.643,92 €	37.796.321,42 €	35.693.148,92 €

Tab. 5-30 Calculation of the total annual tubing costs for the worst case

Tubing costs (Worst case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
10% of the not already completely exchanged wells are exchanged as Standard:		10%	10%	10%	10%	10%
Annual tubing material costs [Euro/year]:	14.021.150,00 €	13.320.092,50 €	12.619.035,00 €	11.917.977,50 €	10.936.497,00 €	9.955.016,50 €
Additional annual exchange rate		5,00%	5,00%	5,00%	7,00%	7,00%
Annual tubing material costs [Euro/year]:	7.014.364,50 €	7.014.364,50 €	7.014.364,50 €	9.820.110,30 €	9.820.110,30 €	9.820.110,30 €
Annual lining process costs [Euro/year]:	1.877.015,14 €	1.877.015,14 €	1.877.015,14 €	2.627.821,20 €	2.627.821,20 €	2.627.821,20 €
Annual wall thickness survey costs [Euro/year]:		1.136.850,00 €	1.136.850,00 €	1.136.850,00 €	1.591.590,00 €	1.591.590,00 €
Total annual exchange rate:		15,00%	14,50%	14,00%	15,50%	14,80%
Total annual tubing costs [Euro/year]:	22.912.529,64 €	23.348.322,14 €	22.647.264,64 €	25.502.759,00 €	24.976.018,50 €	23.994.538,00 €

5.4.2 Production increase and intervention cost savings for the best case

In the preceding chapters the intervention frequency decrease due to the employment of new tubing materials has been assumed and the calculation of the tubing material costs for the best, the worst and the most realistic cases have been executed. Based on these data the **production increase**, the **annual revenues** and **intervention cost savings** due to the employment of new tubing materials have been calculated.

The increase in production is caused by the reduced number of interventions per year, which leads to a greater production time and hence more production. Therefore higher annual revenues are realized due to the production increase. Furthermore the reduced number of interventions per year leads to reduced annual intervention costs, which are additional savings due to the reduced intervention frequency.

In the best case of the new tubing material employment the actual exchange rate of 10% will be maintained and an additional 15% of the wells are equipped in the first three years and then an additional 20% are equipped in the following years. This exchange procedure has already been described in detail in the preceding chapter. The assumed intervention frequency reduction due to new tubing material employment in the best case is shown on Tab. 5-24. The estimation of the production increase, the annual revenues and the intervention cost savings in the future due to a reduced number of interventions has been carried out in the following manner.

The annual production increase, annual revenues and the intervention cost savings have been evaluated separately for the annual percentage of wells which are additionally completely equipped with new material equipment. That means that these values have been calculated at first for the 15% of the wells which are equipped in the first year, then for the 15% which are equipped in the second year and so on. At the end of the calculations, the calculated values have been summed up to get the total production increase, the total annual revenues and total annual intervention cost savings for the best case.

Tab. 5-31 displays the calculation of the annual production increase, the annual revenues and the annual intervention cost savings for the 15% of the wells which are equipped in the first year. To demonstrate how these values have been estimated, the calculation of the first year will be described. For the following years the values have been estimated according to the same procedure. The calculation of the annual production increase, the annual revenues and the annual intervention cost savings due to the employment of the corrosion inhibitor has been carried out in a similar way. The differences in the two calculations are the number of yearly equipped wells and the assumed intervention frequency decrease due to the new technology employment. The intervention frequency decrease for the new tubing material employment has been assumed more strongly than for the corrosion inhibitor employment.

Tab. 5-31 Annual production increase, annual revenues and annual intervention cost savings of the 15% of the wells equipped with new tubing material in the first year

Tubing string (Best case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	15,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		13.627,02 €	6.813,51 €	6.813,51 €	4.542,34 €	4.542,34 €
Total intervention costs/year (new) [Euro/year]:		15.491.877,69 €	7.745.938,84 €	7.745.938,84 €	5.163.959,23 €	5.163.959,23 €
Total intervention costs/year (old) [Euro/year]:		25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €
Production losses/well/year [tons/year]:		65,35	29,41	26,47	15,88	14,29
Total production losses/year [tons/year]:		74.296,80	33.433,47	30.090,12	18.054,07	16.248,67
Total production losses/year [bbl/year]:		544.594,05	245.067,32	220.560,59	132.336,35	119.102,72
Total oil production/year (old) [tons/year]:		496.671,30	447.004,25	402.303,82	362.073,44	325.866,10
Total oil production/year (old) [bbl/year]:		3.640.601,25	3.276.541,13	2.948.887,01	2.653.998,31	2.388.598,48
Production increase/year [bbl/year]:		363.062,70	571.823,75	514.641,38	529.345,42	476.410,87
Total oil production/year (new) [bbl/year]:		4.003.663,95	3.848.364,88	3.463.528,39	3.183.343,73	2.865.009,36
Revenues / year [Euro/year]:		180.184.877,75 €	173.178.419,49 €	155.858.777,54 €	143.250.467,75 €	128.925.420,98 €
Savings due to reduced interventions/year[Euro/year]:		10.327.918,46 €	18.073.857,30 €	18.073.857,30 €	20.655.836,92 €	20.655.836,92 €

The evaluation of the following data was necessary to estimate the production increase, the annual revenues generated by the production and the annual savings of the 15% of the wells, which are completely exchanged in the first year:

- **annual intervention costs per well for 6 interventions per year**
- **annual intervention costs for 6 interventions per well for the 15% of the wells**
- **annual intervention costs for 10 interventions per well for the 15% of the wells**
- **annual savings due to the reduced number of interventions from 10 to 6**
- **annual production losses per well for 6 interventions per year**
- **annual production losses of the 15% of the wells**
- **annual oil production of the 15% of the wells**
- **annual oil production of the old scenario of the 15% of the wells**
- **annual production increase and**
- **annual revenue**

All these data have been calculated in the same way as they have been calculated for the employment of the corrosion inhibitor, but for a different number of yearly equipped wells and a different intervention frequency decrease. That means that the **annual intervention costs per well** have been calculated as the product of the assumed average number of interventions per well per year and the average intervention costs of 2,271.15 Euro. For the first year of the installation the number of interventions per well is assumed at a rate of 6 as is displayed on Tab. 5-24. The intervention costs of the following years have been calculated by using the intervention frequencies, which are also shown on Tab. 5-24.

The **annual intervention costs for 6 interventions per well for 15% of the wells are** the product of the intervention costs per well multiplied by the total number of sucker rod pumped wells multiplied again by 15%. Assuming 6 interventions per well these intervention costs are lower than for the actual 10 interventions per well per year.

Then, the **annual intervention costs assuming 10 interventions per well for the 15% of the wells** have been calculated. They are displayed in the fifth row of Tab. 5-31. The difference between the intervention costs for 10 interventions per well and for 6 interventions per well are the **savings due to the reduced number of interventions,** which are shown in the last row of the table. These savings are just a part of the total savings and must not be mistaken with the total savings due to the employment of the new tubing material. These total savings are calculated as the difference in the net present value of the old and the new scenarios.

Afterwards, the **total production losses of the 15% of the wells** have been evaluated. For this purpose the **annual production losses per well** have been calculated. They are the product of the total production losses caused by one intervention - including dead time, intervention time and start up time - and the assumed intervention frequency in the first year.

The **total production losses of the 15% of the wells** have then been calculated as the product of the annual production losses per well and the number of wells. As it also mentioned in preceding chapters the oil production of 93,000 bbl per day already takes into consideration these production losses, and so they do not have to be subtracted from this number.

The **total oil production of the 15% of the wells** has been calculated as the sum of the **total oil production of the 15% of the wells assuming 10 interventions per well** and the **annual production increase** due to a lower number of interventions.

The **total oil production of the old scenario with 10 interventions per well** is the current average production rate per well per day multiplied by 365 times the number of equipped wells in the first year. The **production increase** is calculated as the product of the production losses per intervention per well, the intervention frequency decrease of 4 and the number of equipped wells in the first year.

The **annual revenue** for the first year is the product of the total oil production of the 15% the wells, which are equipped in the first year, and the crude oil price in Euro. The annual revenues are shown in Euro per year at the end of Tab. 5-31.

The next step in the calculation model is the evaluation of the **annual revenues for the 15% of the wells** which are **equipped** with new tubing material **in the second year**. They have been calculated in the same manner as the annual revenues for the 15% of the wells equipped in the first year. Tab. 5-32 shows the calculation table of the annual production increase, the annual revenues and the annual savings due to the reduced number of interventions for the 15% of the sucker rod pumped wells which are equipped in the second year. The difference to the wells which are equipped in the first year is that there are no savings due to reduced interventions and no production increase in the first year. The reason for this is that these wells still have an intervention frequency of 10 interventions per well per year until the new tubing material is installed in the second year. Therefore, no changes can be observed in the first year.

The structure of the tables for the wells which are equipped with new tubing material in the third, the fourth and the fifth years is the same. The annual intervention frequency of the wells which are equipped in the third year stays at 10 until the second year. Therefore the intervention frequency for the wells which are equipped in the fourth and fifth years remains at 10 interventions per year until they are equipped with new tubing materials. That means that these wells also show no production increase and no savings until they are equipped with new tubing material. In the best case, 15% of the sucker rod pumped wells are not equipped with new tubing materials. The annual intervention frequency of these wells remains at 10 until the end of the calculation model. The tables concerning the wells which are equipped in the third, fourth and fifth years and the wells which are not equipped with new sucker rod string are displayed on Tab. 10-9, Tab. 10-10, Tab. 10-11 and Tab. 10-12 in the Appendix.

Tab. 5-32 Annual production increase, annual revenues and annual intervention cost savings of the 15% of the wells equipped with new tubing material in the second year

Tubing string (Best case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	15,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	13.827,02 €	6.813,51 €	6.813,51 €	4.542,34 €
Total intervention costs/year (new) [Euro/year]:		25.819.798,15 €	15.491.877,09 €	7.745.938,84 €	7.745.938,84 €	5.163.958,23 €
Total intervention costs/year (old) [Euro/year]:		25.819.798,15 €	25.819.798,15 €	25.819.798,15 €	25.819.798,15 €	25.819.798,15 €
Production losses/well/year [tons/year]:		108,92	58,82	26,47	23,82	14,29
Total production losses/year [tons/year]:		123.827,86	66.866,94	30.090,12	27.081,11	16.248,67
Total production losses/year [bbl/year]:		907.656,75	490.134,65	220.560,59	198.504,53	119.102,72
Total oil production/year (old) [tons/year]:		496.671,30	380.137,31	372.213,70	334.992,33	309.817,43
Total oil production/year (old) [bbl/year]:		3.640.601,25	2.786.406,48	2.728.326,47	2.455.493,78	2.269.495,78
Production increase/year [bbl/year]:		0,00	326.756,43	514.641,38	463.177,24	476.410,87
Total oil production/year (new) [bbl/year]:		3.640.601,25	3.113.162,91	3.242.967,80	2.918.671,02	2.745.906,64
Revenues / year [Euro/year]:		163.827.056,25 €	140.092.330,95 €	145.933.550,98 €	131.340.195,88 €	123.565.798,63 €
Savings due to reduced interventions/year[Euro/year]:		- €	10.327.918,46 €	18.073.857,30 €	18.073.857,30 €	20.655.838,92 €

Finally, the annual oil productions, the annual revenues generated by the production and the annual savings due to the reduced interventions per year of all wells have been added to get the **total annual production**, **total annual revenues** and **total annual savings** for the entire 7,579 sucker rod pumped wells. These figures are represented on Tab. 5-33.

Tab. 5-33 Annual production, annual revenues and annual intervention cost savings of all 7,579 sucker rod pumped wells in the best case

Tubing string (Best case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	100%	of the wells:				
Total oil production/year (new) [bbl/year]:		24.270.675,00	21.353.472,86	19.438.600,16	17.494.817,54	15.804.807,15
Revenues / year [Euro/year]:		1.108.510.196,50 €	1.001.342.306,69 €	934.202.236,56 €	880.653.647,27 €	812.150.475,02 €
Savings due to reduced interventions/year[Euro/year]:		10.327.918,46 €	28.401.775,76 €	48.475.633,06 €	70.574.108,46 €	97.254.565,68 €

On this table it can be observed that the **annual oil production** and **annual revenues** are still decreasing from year to year but the annual production and the annual revenues are higher than on table Tab. 5-5, which displays the annual oil productions and annual revenues for an intervention frequency of 10 interventions per year. Therefore, the annual production decline of ten percent has been reduced due to the employment of new tubing material. The **annual savings due to a reduced number of interventions** are increasing, because the intervention frequency is reduced from year to year, and so the savings caused by this reduction are rising. These facts have also been shown for the employment of new corrosion inhibitor.

5.4.3 Production increase and intervention cost savings for the worst case

Concerning the worst case of the new tubing material employment the actual exchange rate of 10% will also be maintained and an additional 5% of the sucker rod pumped wells will be completely equipped in the first three years. Thereafter 7% of the wells will also be completely equipped in the following years. The assumed intervention frequency development due to new tubing material employment for the worst case is displayed on Tab. 5-26.

The annual production increase, the annual revenues and the annual intervention cost savings due to a reduced number of interventions have been calculated in the same manner as for the best case. The difference is the yearly number of completely exchanged wells. At the end of the calculations for the worst, case all the separately calculated annual production increases, annual revenues and the intervention cost savings have again been added to obtain the total production increase, the total annual revenues and the total number of intervention cost savings for the worst case. Tab. 5-34 represents the calculation table of the 5% of the wells which are equipped with new tubing material in the first year.

Tab. 5-34 Annual production increase, annual revenues and annual intervention cost savings of the 5% of the wells equipped with new tubing material in the first year

Tubing string (Worst case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	5,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		13.627,02 €	6.813,51 €	6.813,51 €	4.542,34 €	4.542,34 €
Total intervention costs/year (new) [Euro/year]:		5.163.959,23 €	2.581.979,61 €	2.581.979,61 €	1.721.319,74 €	1.721.319,74 €
Total intervention costs/year (old) [Euro/year]:		8.606.598,72 €	8.606.598,72 €	8.606.598,72 €	8.606.598,72 €	8.606.598,72 €
Production losses/well/year [tons/year]:		65,35	29,41	26,47	15,88	14,29
Total production losses/year [tons/year]:		24.765,53	11.144,49	10.030,04	6.018,02	5.416,22
Total production losses/year [bbl/year]:		181.531,35	81.689,11	73.520,20	44.112,12	39.700,91
Total oil production/year (old) [tons/year]:		165.557,13	149.001,42	134.101,27	120.691,15	108.622,03
Total oil production/year (old) [bbl/year]:		1.213.533,75	1.092.180,38	982.962,34	884.666,10	796.199,49
Production increase/year [bbl/year]:		121.020,90	190.607,92	171.547,13	176.448,47	158.803,62
Total oil production/year (new) [bbl/year]:		1.334.554,65	1.282.788,29	1.154.509,46	1.061.114,58	955.003,12
Revenues / year [Euro/year]:		60.054.959,25 €	57.725.473,18 €	51.952.925,85 €	47.750.155,97 €	42.975.140,33 €
Savings due to reduced interventions/year[Euro/year]:		3.442.639,49 €	6.024.619,10 €	6.024.619,10 €	6.885.278,97 €	6.885.278,97 €

The necessary data to estimate the annual production increases, annual revenues and the intervention cost savings of the first year are the:

- **annual intervention costs per well for 6 interventions per year**
- **annual intervention costs for 6 interventions per well for the 5% of the wells which are completely exchanged**
- **annual intervention costs for 10 interventions per well for the 5% of the wells (old scenario)**

- **annual savings due to the reduced number of interventions from 10 to 6**
- **annual production losses per well for 6 interventions per year**
- **annual production losses of the 5% of the wells**
- **annual oil production of the 5% of the wells**
- **annual oil production of the old scenario of the 5% of the wells**
- **annual production increase and**
- **annual revenue.**

The calculation procedure for these data is the same as for the best case, the only difference is the percentage of equipped wells per year.

Tab. 5-35 shows the calculations of the annual production increases, the annual revenues and the intervention cost savings for the 5% of the wells which are equipped in the second year. Due to the fact that these wells are equipped with new tubing materials in the second year, it can be seen that the total intervention costs per year do not decrease earlier.

Tab. 5-35 Annual production increase, annual revenues and annual intervention cost savings of the 5% of the wells equipped with new tubing material in the second year

Tubing string (Worst case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	5.00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	13.827,02 €	6.813,51 €	6.813,51 €	4.542,34 €
Total intervention costs/year (new) [Euro/year]:		8.606.598,72 €	5.163.958,23 €	2.581.979,61 €	2.581.979,61 €	1.721.319,74 €
Total intervention costs/year (old) [Euro/year]:		8.606.598,72 €	8.606.598,72 €	8.606.598,72 €	8.606.598,72 €	8.606.598,72 €
Production losses/well/year [tons/year]:		108,92	58,82	26,47	23,82	14,29
Total production losses/year [tons/year]:		41.275,89	22.288,98	10.030,04	9.027,04	5.416,22
Total production losses/year [bbl/year]:		302.552,25	163.378,22	73.520,28	66.168,18	39.700,91
Total oil production/year (old) [tons/year]:		165.557,13	149.001,42	134.101,27	120.691,15	108.622,03
Total oil production/year (old) [bbl/year]:		1.213.533,75	1.092.180,38	982.962,34	884.666,10	796.199,49
Production increase/year [bbl/year]:		0,00	108.918,81	171.547,13	154.392,41	158.003,02
Total oil production/year (new) [bbl/year]:		1.213.533,75	1.201.099,19	1.154.509,46	1.039.058,57	955.003,12
Revenues / year [Euro/year]:		56.609.018,75 €	56.049.463,33 €	51.952.925,85 €	46.757.633,20 €	42.975.140,33 €
Savings due to reduced interventions/year [Euro/year]:		- €	3.442.639,49 €	6.024.619,10 €	6.024.619,10 €	6.885.278,97 €

The calculations of the annual production increases, the annual revenues and the annual intervention cost savings for the wells which are completely equipped in the third, the fourth and the fifth years can be observed on Tab. 10-13, Tab. 10-14 and Tab. 10-15 in the Appendix. It is also important to mention that the annual intervention frequency per well for these wells stays at 10 until the new tubing material is installed. For this reason, these wells show again no savings and no production increase until the new tubing material is installed.

In the worst case scenario of new tubing material installation, almost 30% of all sucker rod pumped wells are completely equipped with new tubing material in the five years of the calculation model. For the rest of the wells, the intervention frequency always remains at 10 and consequently no savings and no production increase is realized with these wells. The calculation of the annual production increases, the annual revenues and the annual intervention cost savings for these wells can be seen on Tab. 10-16 in the Appendix.

After that, the results of all the calculation tables have been summed up to produce the figures for the **annual production,** the **annual revenues** and the **annual savings** for all of the 7,579 sucker rod pumped wells. These figures are shown on Tab. 5-36.

Tab. 5-36 Annual production, annual revenues and annual intervention cost savings of all 7,579 sucker rod pumped wells in the worst case

Tubing string (Worst case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	100%	of the wells:				
Total oil production/year (new) [bbl/year]:		24.270.675,00	21.843.607,50	19.659.246,75	17.693.322,08	15.923.989,87
Revenues / year [Euro/year]:		1.097.626.315,50 €	986.441.040,24 €	904.516.556,07 €	823.593.118,60 €	750.081.127,03 €
Savings due to reduced interventions/year [Euro/year]:		3.442.639,49 €	9.467.258,50 €	15.491.877,89 €	23.754.217,45 €	33.049.339,07 €

Concerning the worst case scenario the **annual productions** and the **annual revenues** are also higher than on Tab. 5-5, which displays the annual oil productions and annual revenues for an intervention frequency of 10 interventions per year. But in comparison to the best case, these figures are lower, because in the worst case less sucker rod pumped wells are completely exchanged with new tubing material. Therefore, the annual production decline of ten percent has also been reduced, but, of course, not as strong as in the best case. Due to the lower number of newly equipped wells, the **annual savings due to a reduced number of interventions** are also lower than in the best case.

5.4.4 Production increase and intervention cost savings for the realistic case

In the most realistic case of the new tubing material employment the actual exchange rate of 10% will again be maintained. As already explained, this 10% will be replaced in stages. Additionally, 10% of the sucker rod pumped wells are completely equipped in the first three years, and afterwards 10% of the wells are additionally completely equipped in the following years. For the estimation of the annual production increase, the annual revenues and the intervention cost savings due to a reduced number of interventions per year the same procedure has been applied as for the best and the worst cases. The difference is the percentage of completely equipped wells per year and consequently the number of wells that are affected by the reduced intervention frequency per year. The assumed intervention frequency development due to new tubing material employment for the most realistic case is displayed on Tab. 5-25. On Tab. 5-37 the calculation table of the 10% of the wells which have been equipped with new tubing material in the first year is displayed. The table has the same structure as those for the best and the worst cases.

Tab. 5-37 Annual revenues and annual intervention cost savings of the 10% of the wells equipped with new tubing material in the first year

Tubing string (Most realistic case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	10,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		13.627,02 €	6.813,51 €	6.813,51 €	4.542,34 €	4.542,34 €
Total intervention costs/year (new) [Euro/year]:		10.327.918,46 €	5.163.959,23 €	5.163.959,23 €	3.442.639,49 €	3.442.639,49 €
Total intervention costs/year (old) [Euro/year]:		17.213.197,43 €	17.213.197,43 €	17.213.197,43 €	17.213.197,43 €	17.213.197,43 €
Production losses/well/year [tons/year]:		65,35	29,41	26,47	15,88	14,29
Total production losses/year [tons/year]:		49.531,06	22.288,98	20.080,08	12.036,05	10.832,44
Total production losses/year [bbl/year]:		363.062,70	163.378,22	147.040,39	88.224,24	79.401,81
Total oil production/year (old) [tons/year]:		331.114,26	298.002,83	268.202,55	241.382,29	217.244,06
Total oil production/year (old) [bbl/year]:		2.427.067,50	2.184.360,75	1.965.924,68	1.769.332,21	1.592.398,99
Production increase/year [bbl/year]:		242.041,80	381.215,84	343.094,25	392.896,94	317.607,25
Total oil production/year (new) [bbl/year]:		2.669.109,30	2.565.576,59	2.309.018,93	2.172.229,15	1.910.006,24
Revenues / year [Euro/year]:		120.109.918,50 €	115.450.946,33 €	103.905.851,69 €	95.500.311,84 €	85.950.280,65 €
Savings due to reduced interventions/year[Euro/year]:		6.885.278,97 €	12.049.238,20 €	12.049.238,20 €	13.770.557,94 €	13.770.557,94 €

All the data which is listed on table has then been calculated. These data have been calculated in the same manner as for the best case and the worst cases, but as already mentioned, for a different number of equipped wells per year. The procedure of these calculations has already been described in detail in the last two chapters.

Tab. 5-38 shows the calculation table of the annual revenues and the savings due to the reduced number of interventions for the 10 % of the wells which are equipped with new tubing material in the second year. As could be observed in the best and worst cases too, the total intervention costs per year do not decrease in the first year, because no new tubing material is installed. Therefore the number of interventions per well is still at 10 in the first year. As a consequence there are also no savings due to reduced interventions and no production increase for these 10 % of the wells in the first year.

Tab. 5-38 Annual revenues and annual intervention cost savings of the 10% of the wells equipped with new tubing material in the second year

Tubing string (Most realistic case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	10,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	13.627,02 €	6.813,51 €	6.813,51 €	4.542,34 €
Total intervention costs/year (new) [Euro/year]:		17.213.197,43 €	10.327.918,46 €	5.163.959,23 €	5.163.959,23 €	3.442.639,49 €
Total intervention costs/year (old) [Euro/year]:		17.213.197,43 €	17.213.197,43 €	17.213.197,43 €	17.213.197,43 €	17.213.197,43 €
Production losses/well/year [tons/year]:		108,92	58,82	26,47	23,82	14,29
Total production losses/year [tons/year]:		82.551,77	44.577,96	20.080,08	18.054,07	10.832,44
Total production losses/year [bbl/year]:		605.104,50	326.756,43	147.040,39	132.336,35	79.401,81
Total oil production/year (old) [tons/year]:		331.114,26	298.002,83	268.202,55	241.382,29	217.244,06
Total oil production/year (old) [bbl/year]:		2.427.067,50	2.184.360,75	1.965.924,68	1.769.332,21	1.592.398,99
Production increase/year [bbl/year]:		0,00	217.837,62	343.094,25	308.784,83	317.607,25
Total oil production/year (new) [bbl/year]:		2.427.067,50	2.402.198,37	2.309.018,93	2.078.117,03	1.910.006,24
Revenues / year [Euro/year]:		109.218.037,50 €	108.098.926,65 €	103.905.851,69 €	93.515.266,52 €	85.950.280,65 €
Savings due to reduced interventions/year[Euro/year]:		- €	6.885.278,97 €	12.049.238,20 €	12.049.238,20 €	13.770.557,94 €

The calculations of the annual production increases, the annual revenues and the annual intervention cost savings for the wells which are completely equipped in the third, fourth and fifth years can be seen on Tab. 10-17, Tab. 10-18 and Tab. 10-19 in the Appendix. For these wells, the annual intervention frequency per well stays at 10 until the new tubing material is installed. Therefore, these wells show again no savings and no production increase until the installation of the new tubing material.

Concerning the most realistic case of new tubing material installation for 60% the sucker rod pumped wells, the intervention frequency always remains at 10 and consequently no savings and no production increase is achieved with these wells. The calculation of the annual production increases, the annual revenues and the annual intervention cost savings for these wells can be seen on Tab. 10-20 in the Appendix.

Afterwards, the results of all the particular calculation tables have been summed up again to receive the **annual production,** the **annual revenues** and the **annual savings** for all of the 7,579 sucker rod pumped wells. They are represented on Tab. 5-39.

Tab. 5-39 Annual production, annual revenues and annual intervention cost savings of all 7,579 sucker rod pumped wells in the most realistic case

Tubing string (Most realistic case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	100%	of the wells:				
Total oil production/year (new) [bbl/year]:		24.270.675,00	21.843.607,50	19.659.246,75	17.693.322,08	15.923.989,87
Revenues / year [Euro/year]:		1.103.072.256,00 €	1.009.919.742,98 €	924.367.010,00 €	851.700.762,17 €	787.147.904,09 €
Savings due to reduced interventions/year [Euro/year]:		6.085.270,97 €	18.934.517,17 €	30.983.755,37 €	48.196.952,00 €	67.092.179,05 €

The annual oil productions and revenues generated by the production are again higher than on Tab. 5-5, which shows the annual oil productions and annual revenues for an intervention frequency of 10 interventions per year. The actual production decline of 10% has also been reduced over the years of the calculation model. The reduction of this decline is more significant than in the worst case, but less significant than in the best one. Therefore also the annual oil productions, the annual revenues and the savings lie between the results of the assumed best case and the assumed worst case. The same fact could be noted for the employment of the corrosion inhibitor.

The total annual oil productions and the annual production increase due to the employment of tubing materials – in absolute numbers and in percent – are displayed on Fig. 10-4, Fig. 10-5 and Fig. 10-6 in the Appendix.

5.4.5 Difference in net present value for the best, worst and realistic cases

For the calculation of the total savings due to the employment of new tubing material, the net present value of the unchanged future scenario has been calculated.

This scenario includes no installation of new tubing material and consequently assumes that the intervention frequency of 10 interventions per year is not being reduced. Afterwards this value was compared to the net present value which assumes a reduced number of interventions. The difference of both present values is the total savings which can be achieved by the employment of new tubing material. As was already mentioned these total savings are the differences between the net present values of both scenarios and must not be mistaken with the savings due a reduced number of intervention. The calculation of the annual cash flows considering the employment of new tubing material has been evaluated in accordance with the following:

Annual revenues (generated by the oil production)

\+ Annual savings (due to reduced interventions)

\- Annual total tubing costs

= Annual cash flows

After that the calculation of the annual cash flows for the scenario which considers no employment of new tubing material has been carried out. Considering this scenario the intervention frequency has not been decreased and therefore no annual savings are realized, but also no additional investment costs have to be expended. Thus the annual revenues equal the annual cash flows. The calculation of the difference in net present value for the best case of the employment of new tubing material is shown on Tab. 5-40. The calculation tables of the difference in net present value for the worst case and the most realistic case of the employment of new tubing material are displayed on Tab. 10-21 and Tab. 10-22 in the Appendix.

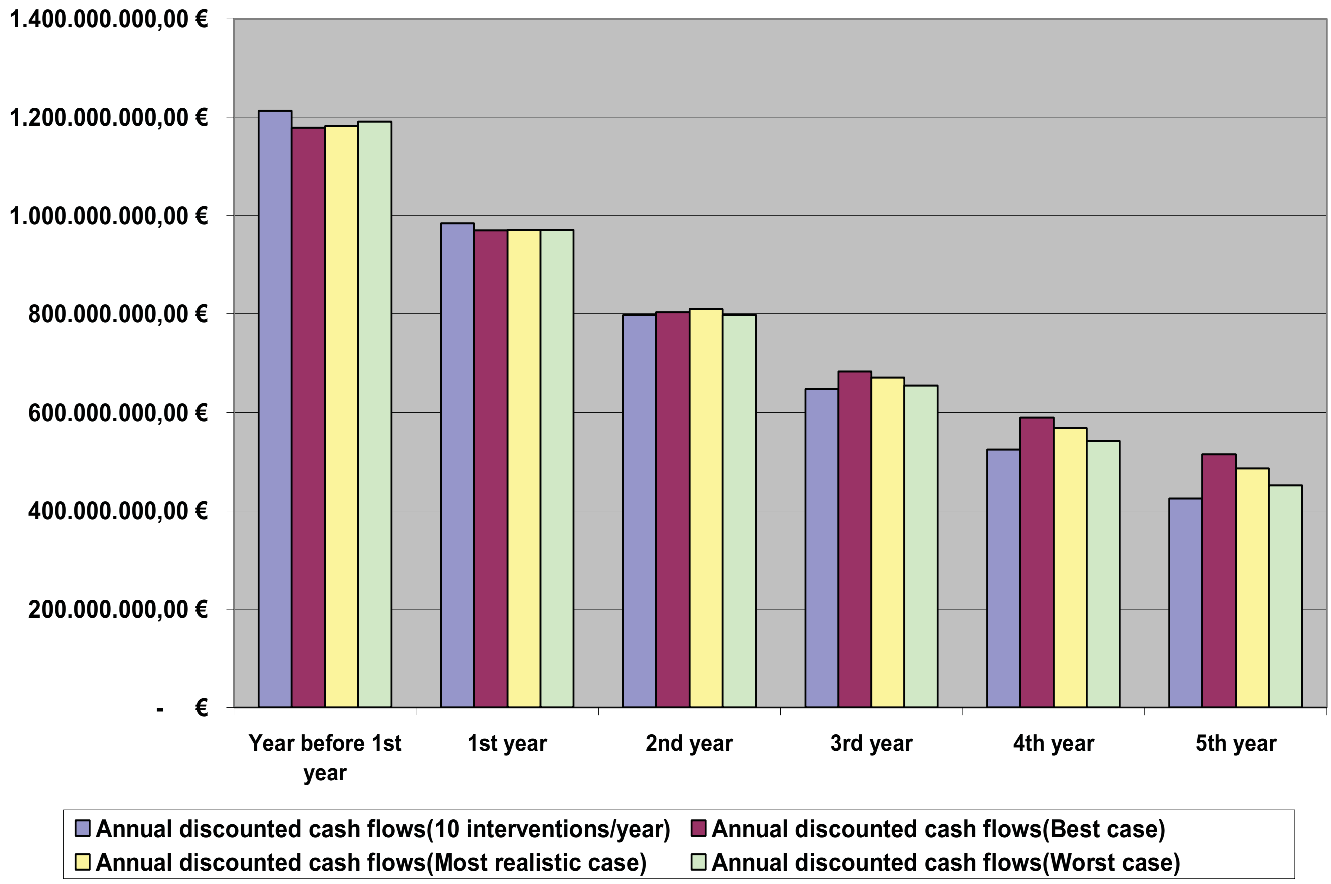
Tab. 5-40 Difference in net present value for the best case

Tubing string (Best case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Annual revenues due to the oil production [Euro/year]:	1.213.533.750,00 €	1.108.518.196,50 €	1.001.342.386,69 €	934.292.736,56 €	868.653.647,27 €	812.158.475,82 €
Annual savings due to reduced interventions [Euro/year]:		10.327.918,46 €	28.401.776,76 €	46.475.633,06 €	70.574.109,46 €	97.254.566,48 €
Tubing costs [Euro/year]:	35.064.243,50 €	42.002.666,42 €	39.899.493,92 €	46.687.791,06 €	45.020.321,06 €	42.216.091,06 €
Annual cash flow(Best case)[Euro/year]:	1.178.469.506,50 €	1.076.843.448,54 €	989.844.668,51 €	934.080.108,56 €	894.207.435,68 €	867.197.950,24 €
Annual discounted cash flow(10interventions/year)[Euro/year]:	1.213.533.750,00 €	983.946.283,78 €	797.794.284,15 €	646.860.230,39 €	524.481.267,38 €	425.255.482,07 €
Annual discounted cash flow(Best case)[Euro/year]:		970.129.232,92 €	803.380.138,40 €	682.991.368,69 €	589.042.135,10 €	514.639.775,26 €
Net present value (10 interventions per year)[Euro/year]:		2.197.480.033,78 €	2.995.274.317,93 €	3.642.134.548,32 €	4.166.615.816,21 €	4.591.870.898,28 €
Net present value (Best case)[Euro/year]:		2.148.598.739,42 €	2.951.978.877,82 €	3.634.970.246,51 €	4.224.012.381,70 €	4.738.652.156,96 €
Difference in net present value [Euro/year]:	- 35.064.243,50 €	- 48.881.294,37 €	- 43.205.440,11 €	- 7.164.201,81 €	57.306.565,50 €	146.781.258,69 €

First, the calculation of the annual cash flows for the assumed best case of the employment of new tubing material has been carried out. Then the cash flows for the case without the employment of new tubing material have been calculated. After that, these cash flows have been discounted to account for the time value of the money. The imputed interest rate has again been figured at 11%.

The discounted cash flows for the best, worst, most realistic case and the case without any changes which is characterized by 10 interventions per year are represented on Fig. 5-5.

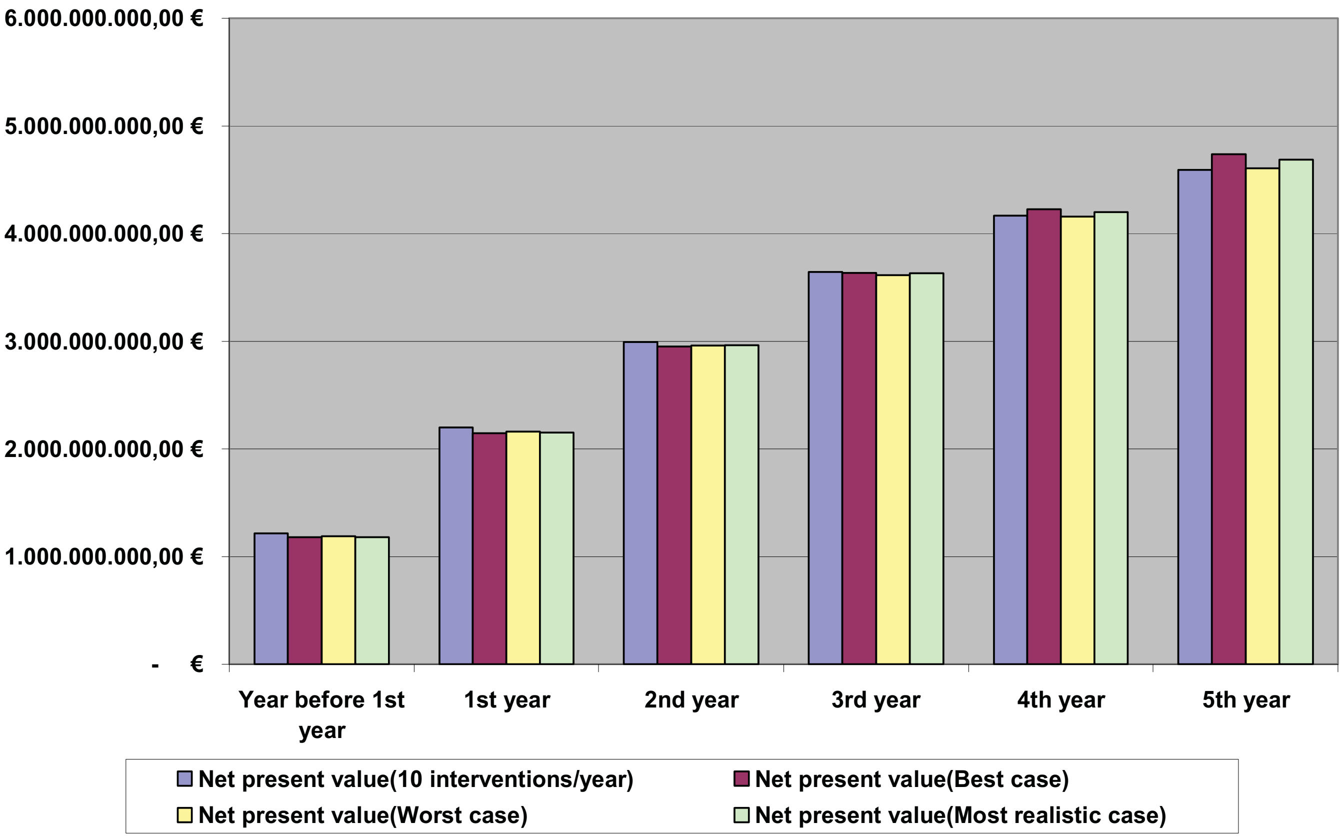
Fig. 5-5 Discounted cash flows for new tubing material scenarios



In the best, the worst and the most realistic cases the discounted cash flows are higher than in the case which considers no employment of new tubing material. The reason for this is that the annual savings due to the reduced number of interventions which are caused by the installation of the new materials are much higher than the annual costs for these new materials. This fact can be seen on Tab. 5-40. Therefore, huge potential savings could be realized by installing new tubing materials. The discounted cash flows of the most realistic case lie between the discounted cash flows of the best and the worst cases.

Then the net present values for the best, the worst and the most realistic cases and for the case without any changes, which is characterized by an intervention frequency of 10, have been computed. They have been calculated as the sum of the discounted cash flows. These net present values for the best case are shown on Fig. 5-6.

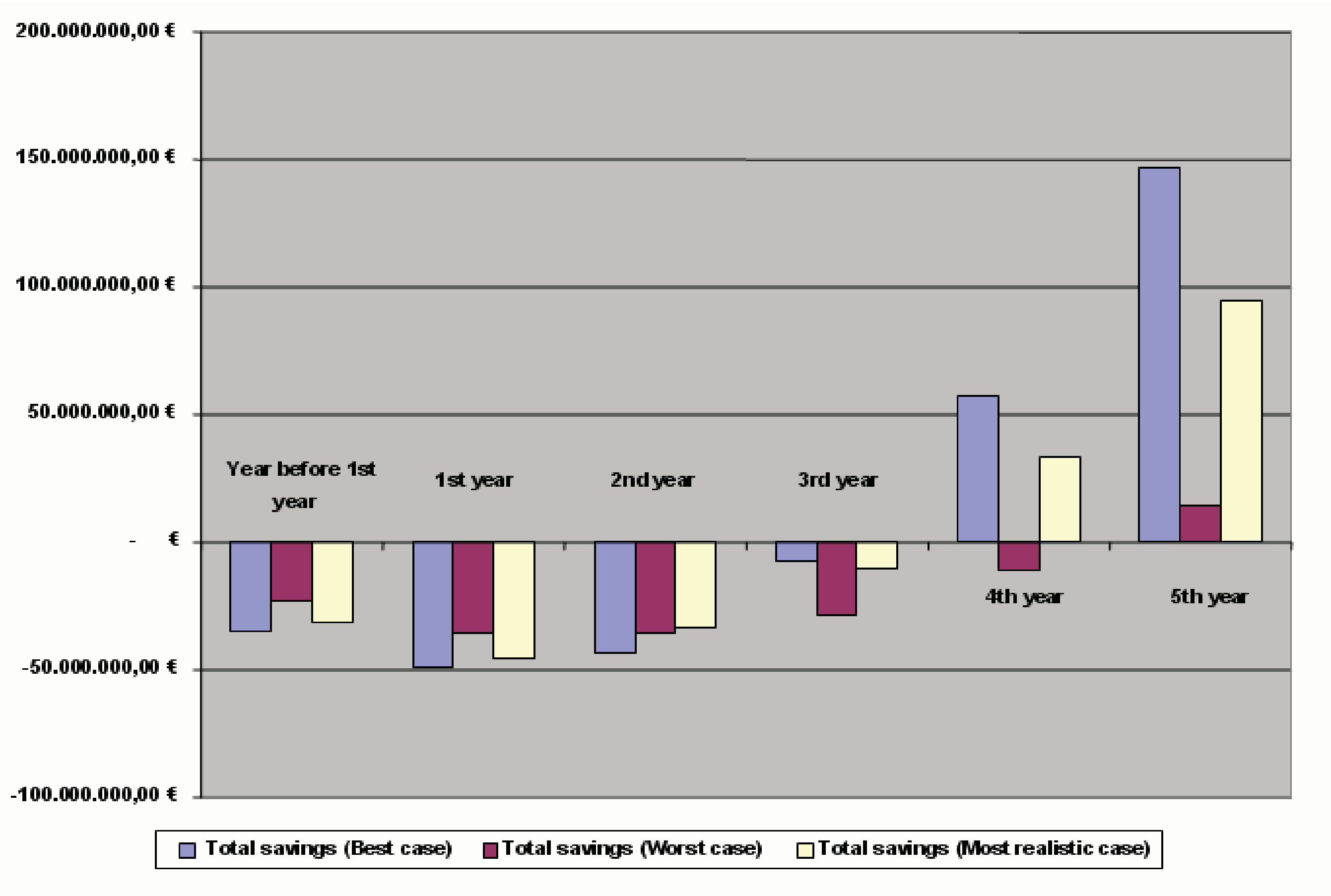
Fig. 5-6 Net present values for different new tubing material scenarios



In the end, the differences of net present values of the best, worst or realistic case and the net present value of the case without any changes have been calculated. They are the cumulative savings realized due to the employment of new tubing material in the best, worst and most realistic cases. The difference of the net present values in the year before the first installation is the tubing costs of this year. This fact can be observed on Tab. 5-40. In the year before the first installation just the purchase of the new tubing material and the thermoplastic tubular liners is made, but no wells are completely equipped in this year. Therefore the intervention frequency cannot be reduced and no savings are realized in the year of the first investment. Since also no discounting takes place in this year the difference of the net present values corresponds with the tubing investment costs. The costs for the wall thickness survey are not included in the tubing investment costs because they belong to the opex, which are initially realized in the first year of installation and not in the first year of investment. This fact is displayed for the best case on Tab. 5-28.

The cumulated savings or differences of the net present values are displayed on Fig. 5-7.

Fig. 5-7 Total savings for different new tubing material scenarios



The payout period is 3.11 years in the best case, 3.23 years in the most realistic case and 4.44 years in the worst case. These payout periods are significantly higher than the payout periods concerning the employment of corrosion inhibitors. The losses in the year before the first installation coincide with the tubing investment costs in this year. This fact can also be seen on Tab. 5-40.

5.5 Sucker rod string

The calculation of the total savings and the annual production increase due to the employment of new sucker rod string material is very similar to the savings and production increase calculation concerning the new tubing material employment. The difference between both scenarios is the reduction of the actual intervention frequency. The assumed annual number of frequencies concerning the employment of new tubing material is lower, because in this scenario the material is not just exchanged, but the new material is also equipped with new plastic tubular liners. This additional equipment causes a stronger reduction of the intervention frequency.

Concerning the installation of new sucker rod strings, three tables which display the assumed development of the intervention frequencies of all wells have been created again. These tables have been made for the best, the worst and the most realistic case scenarios. They have been used to estimate the total savings and the production increase caused by the installation of new sucker rod string material.

After a sucker rod string failure is detected, an intervention is carried out to exchange the broken part. As already mentioned the average depth of a well in Romania has been assumed with 1,000 meters and the length of a single sucker rod is about ten meters. For this reason, on average about one hundred single sucker rods are installed in every well. Due to the annual intervention frequency of 10 interventions per well per year, about 10 single sucker rods are exchanged per well per year. These are 10% of the 100 single sucker rods in a well. On the basis of this procedure it has been assumed that about 10% of the sucker rod strings are replaced per year in Romania at the moment. The same assumption has been applied to estimate the actual exchange rate of tubing material in Romania.

For the reduction of the actual intervention frequency of 10 interventions per well per year a certain percentage of wells is supposed to be completely exchanged with new sucker rod string material in Romania. These new sucker rod strings are additionally equipped with protectors to centralize the string. Furthermore a new, or at least, repaired sucker rod pump is installed in every completely exchanged well.

The percentage of completely exchanged wells per year for the best, worst and most realistic case is also the same as for the scenarios which concern the new tubing material installation. That means that for best case, 15% of the wells are completely replaced with new sucker rod string material in the first three years and then 20% are completely replaced in the fourth and fifth years of the calculation model. Additionally all the wells which have not been completely exchanged, will still have 10 interventions per year, and so an exchange rate of ten percent per year. But this 10% is replaced by exchanging the damaged sucker rods piecewise.

Consequently in the first year of new sucker rod string installation, 15% of all sucker rod pumped wells are completely replaced with new sucker rod string material and 10% are exchanged in stages as it has been standard in Romania until now. In the first year this is exactly 25% of all sucker rod string material. The number of wells which still include old sucker rod string material is decreasing annually. Ten percent of the wells including old sucker rod string material are also exchanged gradually in the following years, but compared to the entire sucker rod pumped wells, these are less than 10% due to the decreasing number of wells with old material. Therefore, the percentage of completely exchanged wells is increased after the third year. By doing this the whole percentage of newly installed wells is again about 25%, otherwise it would decrease.

Tab. 5-41 shows the development of the assumed annual intervention frequency of the wells which are completely exchanged with new sucker rod string material in the best case. The first row of the table shows the years of the calculation model and the first column represents the percentage of annually completely equipped wells.

Tab. 5-41 Development of the intervention frequencies due new sucker rod string material in the best case

Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
15,00%	7,5	5	5	4	4
15,00%	10	7,5	5	5	4
15,00%	10	10	7,5	5	5
20,00%	10	10	10	7,5	5
20,00%	10	10	10	10	7,5
15,00%	10	10	10	10	10

The intervention frequency of the 15% of the wells which are completely equipped with new sucker rod string material in the first year has been assumed as a rate of 7.5 interventions per well per year in this year. In the second year of the installation their intervention frequency decreases to 5, and in the fourth year to 4. In the first year, it has been assumed at a significantly higher rate than in the following years, as it has been done for the employment of corrosion inhibitor and new tubing material. The reason for this is that not all wells can be equipped at the same time. In the first year of installation, the other 85% of the wells are not equipped with new sucker rod string material. For this reason, their intervention frequency remains at 10 interventions per well per year.

The 15% of the wells which are completely equipped with new material in the second year show an intervention frequency of 7.5 in the second year. The intervention frequency of these wells has the same development as the wells which have been equipped in the first year, but with a delay of one year.

Wells which are later equipped with the new sucker rod string material show the same development of the intervention frequency, but with a delay of for example two years if they are equipped in the third year or with a delay of four years if they are equipped in the fifth year. This fact is also shown on Tab. 5-41. In the best case scenario of new sucker rod string installation 15% of the wells are not equipped with new tubing material. For this reason the intervention frequency of these wells always stays at 10, which can be seen in the last row of Tab. 5-41.

Concerning the most realistic case of new sucker rod string installation, 10% are again exchanged in stages as has been standard in Romania until now. Furthermore, 10% of the sucker rod string material is replaced by exchanging complete sucker rod strings in the first three years and 15% of the sucker rod string material is replaced by exchanging complete sucker rod strings in the fourth and fifth years. The reason for the increase of the percentage of wells which are completely exchanged with new sucker rod string material in the fourth year is the same as in the best case. Altogether about 20% of the tubing material is exchanged every year.

Tab. 5-42 displays the development of the assumed annual intervention frequency of the wells which are completely exchanged with new sucker rod string material in the most realistic case.

Tab. 5-42 Developing of the intervention frequencies due to new sucker rod string material employment in the most realistic case

Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
10,00%	7,5	5	5	4	4
10,00%	10	7,5	5	5	4
10,00%	10	10	7,5	5	5
15,00%	10	10	10	7,5	5
15,00%	10	10	10	10	7,5
40,00%	10	10	10	10	10

The table shows the same development of the intervention frequencies as for the best case. The difference to the best case is that a smaller percentage of wells are equipped with new sucker rod string material and so fewer wells are affected by an intervention frequency decrease. 40% of the sucker rod pumped wells are not equipped with new sucker rod string material during the five years of the calculation model in the most realistic case. The intervention frequency of these wells always stays at 10.

In the worst case of sucker rod material employment 5% of the sucker rod pumped wells are equipped with new sucker rod string material per year in the first three years and 7% are equipped in the fourth and in the fifth year. Additionally, as in the best and most realistic, case 10% of the sucker rod pumped wells are exchanged in stages as has been standard in Romania until now. The percentage of wells which is completely updated with new tubing material is again increased from 5% to 7% after the third year to maintain an average annual exchange rate of about 15% per year. The reason for this percentage increase has already been explained in the best case. The development of the intervention frequencies for the completely exchanged wells in the worst case is displayed on Tab. 5-43.

Tab. 5-43 Developing of the intervention frequencies due to new tubing material employment in the worst case

Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
5,00%	7,5	5	5	4	4
5,00%	10	7,5	5	5	4
5,00%	10	10	7,5	5	5
7,00%	10	10	10	7,5	5
7,00%	10	10	10	10	7,5
71,00%	10	10	10	10	10

The table for the worst case has the same structure as the tables for the best and the most realistic cases. The significant difference to the best case and the most realistic case is again the smaller percentage of wells which are equipped annually with new sucker rod string material. For this reason a smaller percentage of wells are affected by the intervention frequency decrease. 71% of the sucker rod pumped wells are not equipped with new tubing material during the five years of the calculation model in the assumed worst case. Therefore these wells are characterized by an intervention frequency of 10 as is shown in the last row of Tab. 5-43 .

The calculations of the costs for the new sucker rod string material and the estimates of the total savings due to the employment of new sucker rod string material have been carried out on the basis of these assumed intervention frequencies.

5.5.1 Costs of the new sucker rod string material

The essential data to estimate the costs of the new sucker rod string material are the costs per piece for the sucker rod grade *D special* material, the costs per piece for the rod guides and the average costs for the repair of a sucker rod pump. Other necessary data for the cost estimations are the number of sucker rod pumped wells in Romania, the length of a sucker rod piece and the average number of sucker rod pieces in a well. Like the required data for the tubing material cost calculation, all these data are based on statements of experts from OMV. These data are displayed on Tab. 5-44.

Tab. 5-44 Necessary data for the sucker rod string material costs calculation

Price of sucker rod grade *D special* material	48.4	[Euro/piece]
Rod guide price	12.1	[Euro/piece]
Average costs for a sucker rod pump repair	1,000	[Euro/pump]
Number of sucker rod pumped wells	7,579	[ ]
Length of a sucker rod	10	[meter]
Average number of sucker rods per well	100	[ ]

Tab. 5-45 Calculation of the total annual sucker rod string costs for the best case

Sucker rod string costs (Best case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
10% of the not already completely exchanged wells are exchanged as standard:		10%	10%	10%	10%	10%
Annual sucker rod string material costs for 10% [Euro/year]:	7.172.785,60 €	6.098.850,76 €	5.020.925,07 €	3.945.021,00 €	2.510.487,98 €	1.075.914,84 €
Additional annual exchange rate:		15,00%	15,00%	15,00%	20,00%	20,00%
Additional annual sucker rod string material costs [Euro/year]:	10.758.148,40 €	10.758.148,40 €	10.758.148,40 €	14.345.531,20 €	14.345.531,20 €	14.345.531,20 €
Total annual exchange rate:		25,00%	23,50%	22,00%	25,50%	23,50%
Total annual sucker rod string material costs [Euro/year]:	17.931.914,00 €	16.855.999,16 €	15.780.084,32 €	18.290.552,20 €	16.855.999,16 €	15.421.446,04 €

The calculation of the total annual sucker rod string material costs for the best case is displayed on Tab. 5-45. As already mentioned, every new rod is equipped with three new rod guides to centralize the sucker rod string and every newly installed sucker rod string is also equipped with a repaired sucker rod pump. For this reason the total annual sucker rod string material costs include the costs of the new sucker rod material grade *D special*, the costs of the rod guides and the costs of the pump repairs. In the calculation model all the sucker rod string materials are bought in the year before the installation takes place. Therefore their costs, including the repair costs of the pump, are also realized in the year before the installation.

First of all the calculation of the **annual sucker rod string material costs for the 10 %** of the sucker rod string material which is exchanged as has been standard in Romania until now has been carried out. This 10% refers to the wells which have not already been completely exchanged. In the first year, these are exactly 10% of the entire sucker rod string material which is installed the sucker rod pumped wells. But in the following years this replaced sucker rod string material is decreasing, because of the decreasing number of sucker rod pumped wells which still include old material. The **annual sucker rod string material costs for these 10%** have been calculated by applying the following formula:

$$Annual\,SRS\ material\ \cos ts = a*(1-b)*10\%*((c+d*3)*100+e)$$

$a =$ Number of sucker rod pumped wells

$b =$ Percentage of already exchanged wells

$c =$ Price per piece of the sucker rod grade *D special* material

$d =$ Rod guide price

$e =$ Average costs for a sucker rod pump repair

The rod guide price is multiplied by three because every sucker rod is supposed to be equipped with three rod guides. The sum of the price of a sucker rod and the rod guide price is multiplied with 100, because on average 100 sucker rods are installed a sucker rod pumped well. The results of these calculations are shown in the third row of Tab. 5-45.

The next step is the calculation of the **annual sucker rod string material costs for the additional percentage of tubing material** which is equipped every year. These costs have been calculated by applying the following formula:

$$Annual\,SRS\ material\ \cos ts = a*b*((c+d*3)*100+e)$$

$a =$ Number of sucker rod pumped wells

$b =$ Percentage of completely exchanged wells in the following year

$c =$ Price per piece of the sucker rod grade *D special* material

$d =$ Rod guide price

$e =$ Average costs for a sucker rod pump repair

The percentage of completely exchanged wells is taken from the following year, because, as already explained, the sucker rod string material is bought in the year before the installation takes place. As already described in the preceding chapter, the percentage of the wells which are completely exchanged is increased in the third year. These costs are represented in the fourth row of Tab. 5-45.

For the comparison of the annual exchanged tubing material **the total annual exchange rate** has been calculated. In the year before the first year of installation this is 25%, which is the sum of 10% and the additional installed 15. For the following years the total annual exchange rate has been evaluated by multiplying 10% by the percentage of wells which has not been completely exchanged until the respective year and adding 15% to this product. For the first year of installation for example this is 10% times 85%, which is the percentage of not completely exchanged wells, plus 15%. The result is the total annual exchange rate of new sucker rod string material in the second year, which has to be bought in the first year of the calculation model. This percentage decreases annually as can be observed on Tab. 5-45. Therefore the annual percentage of the wells which are completely exchanged is increased in the third year.

Finally the **total annual tubing costs** have been calculated as the sum of the **annual sucker rod string material costs for the 10 %** of the sucker rod string material which is exchanged as has been standard in Romania and the **annual sucker rod string material costs for the additional percentage of tubing material**. The results of these calculations are shown in the last row of Tab. 5-45.

The total tubing costs for the worst and the most realistic case have been calculated again in the same manner. The outstanding difference in the calculations is the percentage of equipped wells per year. This fact can be observed in the fourth row of Tab. 5-46 and Tab. 5-47.

Tab. 5-46 Calculation of the total annual sucker rod string costs for the most realistic case

Sucker rod string costs (Most realistic case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
10% of the not already completely exchanged wells are exchanged as standard:	10%	10%	10%	10%	10%	10%
Annual sucker rod string material costs for 10% [Euro/year]:	7.172.765,60 €	6.455.489,04 €	5.738.212,48 €	5.020.935,92 €	3.945.021,08 €	2.869.106,24 €
Additional annual exchange rate:	10,00%	10,00%	10,00%	15,00%	15,00%	15,00%
Additional annual sucker rod string material costs [Euro/year]:	7.172.765,60 €	7.172.765,60 €	7.172.765,60 €	10.759.148,40 €	10.759.148,40 €	10.759.148,40 €
Total annual exchange rate:	20,00%	19,00%	18,00%	22,00%	20,50%	19,00%
Total annual sucker rod string material costs [Euro/year]:	14.345.531,20 €	13.628.254,64 €	12.910.978,08 €	15.780.084,32 €	14.704.169,48 €	13.628.254,64 €

Tab. 5-47 Calculation of the total annual sucker rod string costs for the worst case

Sucker rod string costs (Worst case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
10% of the not already completely exchanged wells are exchanged as standard:	10%	10%	10%	10%	10%	10%
Annual sucker rod string material costs for 10% [Euro/year]:	7.172.765,60 €	6.814.127,32 €	6.455.489,04 €	6.096.850,76 €	5.594.757,17 €	5.092.663,58 €
Additional annual exchange rate:	5,00%	5,00%	5,00%	7,00%	7,00%	7,00%
Additional annual sucker rod string material costs [Euro/year]:	3.586.382,80 €	3.586.382,80 €	3.586.382,80 €	5.020.935,92 €	5.020.935,92 €	5.020.935,92 €
Total annual exchange rate:	15,00%	14,50%	14,00%	15,50%	14,80%	14,10%
Total annual sucker rod string material costs [Euro/year]:	10.759.148,40 €	10.400.510,12 €	10.041.871,84 €	11.117.786,68 €	10.615.693,09 €	10.113.599,50 €

5.5.2 Production increase and intervention cost savings for the best case

The next step in the calculation model is the calculation of the **annual production increase**, the **annual revenues** and **annual intervention cost savings** due to the installation of new sucker rod string material. These calculations have been based on the assumed intervention frequency decrease due to the employment of new sucker rod string materials. This reduced number of interventions per year causes an increase in production, which leads to higher annual revenues. The intervention reduction also causes reduced annual intervention costs, which are additional savings due to the reduced intervention frequency. These facts have already been described in relation to the employment of other technologies in preceding chapters.

Concerning the best case of the new sucker rod string material installation 10% of the sucker rod pumped wells are exchanged stepwise as has been standard in Romania until now and additionally 15% are equipped in the first three years and then another 20% are equipped in the following years. The assumed intervention frequency reduction due to the installation of new sucker rod string material in the best case is displayed on Tab. 5-41.

The annual production increase, annual revenues and the intervention cost savings have been calculated separately for the annual percentage of wells which are additionally completely equipped with new sucker rod string material. That means that these values have been evaluated at first for the 15% of the wells which are additionally equipped in the first year, then for the 15% which are equipped in the second year and so on. Finally, the calculated values have been added to obtain the total production increase, the total annual revenues and total annual intervention cost savings for the best case. These calculations have been carried out in the same manner as the annual production increase, annual revenues and the intervention cost savings calculations for the corrosion inhibitor employment and new tubing material installation. The significant difference to the calculation concerning the employment of new corrosion inhibitor is the number of yearly equipped wells. Concerning the installation of new tubing material the difference is the assumed intervention frequency decrease, which has been assumed stronger than for the new sucker rod string material installation.

Tab. 5-48 shows the calculation table of the annual production increase, the annual revenues and the annual intervention cost savings for the 15% of the sucker rod pumped wells which are equipped with new sucker rod string material in the first year.

Tab. 5-48 Annual production increase, annual revenues and annual intervention cost savings of the 15% of the wells equipped with new sucker rod string material in the first year

Sucker rod string (Best case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	15,00%	of the wells:				
Intervention costs/well/year [Euro/year]		17.033,78 €	11.355,85 €	11.355,85 €	9.084,68 €	9.084,68 €
Total intervention costs/year (new) [Euro/year]		19.384.847,11 €	12.909.898,07 €	12.909.898,07 €	10.327.918,46 €	10.327.918,46 €
Total intervention costs/year (old) [Euro/year]		25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €
Production losses/well/year [tons/year]		81,89	49,01	44,11	31,76	28,59
Total production losses/year [tons/year]		92.870,75	55.722,45	50.150,20	36.108,15	32.497,33
Total production losses/year [bbl/year]		680.742,56	408.445,54	367.600,98	264.672,71	238.205,44
Total oil production/year (old) [tons/year]		496.671,38	447.004,25	402.303,82	362.073,44	325.866,10
Total oil production/year (old) [bbl/year]		3.640.601,25	3.276.541,13	2.948.887,01	2.653.998,31	2.388.598,48
Production increase/year [bbl/year]		726.914,19	408.445,54	367.600,98	397.009,06	357.308,16
Total oil production/year (new) [bbl/year]		3.067.515,44	3.684.986,66	3.316.488,00	3.051.007,37	2.745.906,64
Revenues / year [Euro/year]		174.038.194,69 €	165.824.398,01 €	149.241.958,03 €	137.295.331,82 €	123.565.798,63 €
Savings due to reduced interventions/year [Euro/year]		6.454.949,04 €	12.909.898,07 €	12.909.898,07 €	15.491.877,69 €	15.491.877,69 €

The following data have been calculated to estimate the production increase, the annual revenues generated by the production and the annual savings of the 15% of the sucker rod pumped wells, which are completely exchanged in the first year:

- **annual intervention costs per well for 7.5 interventions per year**
- **annual intervention costs for 7.5 interventions per well for the 15% of the wells (old scenario)**
- **annual intervention costs for 10 interventions per well for the 15% of the wells**
- **annual savings due to the reduced number of interventions from 10 to 7.5**
- **annual production losses per well for 7.5 interventions per year**
- **annual production losses of the 15% of the wells**
- **annual oil production of the 15% of the wells**
- **annual oil production of the old scenario of the 15% of the wells**
- **annual production increase**
- **annual revenue**

The calculation of these data has been carried out in the same way as it has been done for the corrosion inhibitor employment and the installation of new tubing material. The calculation of these data has been explained in detail in section 5.3.2 and in section 5.4.2.

Afterwards, the **annual production increase**, the **annual revenues** and **annual intervention cost savings for the 15% of the wells** which are **equipped** with new tubing material **in the second year** have been evaluated. They have been calculated in the same way as has been done for the 15% of the wells equipped in the first year.

Tab. 5-49 shows the calculation table of the annual production increase, the annual revenues and the annual savings due to the reduced number of interventions for the 15% of the sucker rod pumped wells which are equipped in the second year. The considerable difference to the wells which are equipped in the first year is that there are no savings due to reduced interventions and no production increases in the first year, because the new sucker rod string material is installed in the second year. Therefore no changes take place in the first year.

The tables for the wells which are equipped with new sucker rod strings in the third, the fourth and the fifth year have the same structure. The annual intervention frequency of theses wells remains at 10 until the installation of the new sucker rod strings takes place. That means that these wells show again no production increase and no savings until they are equipped with new sucker rod string material.

In the best case, 15% of the sucker rod pumped wells are not completely equipped with new sucker rod strings. The annual intervention frequency of these wells remains at 10 until the end of the calculation model. The tables concerning the wells which are equipped in the third, fourth and fifth year and the wells which are not equipped with new sucker rod strings are shown on Tab. 10-23, Tab. 10-24, Tab. 10-25 and Tab. 10-26 in the Appendix.

Tab. 5-49 Annual production increase, annual revenues and annual intervention cost savings of the 15% of the wells equipped with new sucker rod string material in the second year

Sucker rod string (Best case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	15,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	17.033,78 €	11.355,85 €	11.355,85 €	9.084,68 €
Total intervention costs/year (new) [Euro/year]:		25.819.798,15 €	19.364.847,11 €	12.909.898,07 €	12.909.898,07 €	10.327.918,48 €
Total intervention costs/year (old) [Euro/year]:		25.819.798,15 €	25.819.798,15 €	25.819.798,15 €	25.819.798,15 €	25.819.798,15 €
Production losses/well/year [tons/year]:		108,92	73,52	44,11	39,70	28,59
Total production losses/year [tons/year]:		123.827,86	83.583,67	50.150,20	45.135,18	32.497,33
Total production losses/year [bbl/year]:		907.856,75	612.808,31	367.600,98	330.840,89	238.205,44
Total oil production/year (old) [tons/year]:		496.671,38	447.004,25	402.303,87	362.073,44	325.866,10
Total oil production/year (old) [bbl/year]:		3.640.801,25	3.276.541,13	2.948.887,01	2.653.998,31	2.388.598,48
Production increase/year [bbl/year]:		0,00	204.222,77	367.600,98	330.840,89	357.308,16
Total oil production/year (new) [bbl/year]:		3.640.801,25	3.480.763,89	3.316.488,00	2.984.839,20	2.745.906,64
Revenues / year [Euro/year]:		163.827.056,25 €	156.634.375,22 €	149.241.959,83 €	134.317.763,85 €	123.565.798,83 €
Savings due to reduced interventions/year[Euro/year]:		- €	6.454.949,04 €	12.909.898,07 €	12.909.898,07 €	15.491.877,69 €

At the end of the calculations the annual oil production, the annual revenues generated by the production and the annual savings due to the reduced interventions of all wells have been summed up to arrive at the **total annual production**, **total annual revenues** and **total annual savings** for the entire 7,579 sucker rod pumped wells. These results are displayed on Tab. 5-50.

Tab. 5-50 Annual production, annual revenues and annual intervention cost savings of all 7,579 sucker rod pumped wells in the best case

Sucker rod string (Best case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	100%	of the wells:				
Total oil production/year (new) [bbl/year]:		24.270.675,00	21.043.607,50	19.650.248,75	17.893.322,08	15.923.988,87
Revenues / year [Euro/year]:		1.102.291.513,44 €	1.010.532.411,20 €	926.021.214,42 €	853.765.807,43 €	788.934.445,67 €
Savings due to reduced interventions/year[Euro/year]:		6.454.949,04 €	19.364.847,11 €	32.274.745,18 €	49.918.272,55 €	69.713.469,58 €

The **annual oil production** and **annual revenues** are still decreasing annually but the annual production and the annual revenues are higher than on Tab. 5-5, which represents the annual oil production and annual revenues for an intervention frequency of 10 interventions per year. Therefore the annual production decline of ten percent has been reduced due to the installation of new sucker rod strings. The **annual savings due to a reduced number of interventions** are increasing, because the intervention frequency is reduced from year to year, and so the savings caused by this reduction are rising. These facts have also been shown for the employment of new corrosion inhibitor and for the installation of new tubing material.

5.5.3 Production increase and intervention cost savings for the worst case

In the worst case of the new sucker rod strings installation the actual exchange rate of 10% will also be maintained as has been standard in Romania until now and an additional 5% are completely equipped in the first three years and then another 7% are completely equipped in the fourth and fifth year. Tab. 5-43 represents the assumed intervention frequency reduction due to the installation of new sucker rod string material in the worst case.

The calculation of the annual production increase, the annual revenues and the annual intervention cost savings due to a reduced number of interventions have been carried out in the same manner as for the best case. The difference is the number of wells, which are completely exchanged each year. At the end of the calculations for the worst case, all the separately calculated annual production increases, annual revenues and the intervention cost savings have again been summed up to get the total production increase, the total annual revenues and the total number of intervention cost savings for the worst case. The calculations regarding the 5% of the wells which are equipped with new tubing material in the first year are displayed on Tab. 5-51.

Tab. 5-51 Annual production increase, annual revenues and annual intervention cost savings of the 5% of the wells equipped with new sucker rod strings in the first year

Sucker rod string (Worst case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	5,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		17.033,78 €	11.355,85 €	11.355,85 €	9.084,68 €	9.084,68 €
Total intervention costs/year (new) [Euro/year]:		6.454.948,04 €	4.303.298,36 €	4.303.298,36 €	3.442.638,49 €	3.442.638,49 €
Total intervention costs/year (old) [Euro/year]:		8.606.598,72 €	8.606.598,72 €	8.606.598,72 €	8.606.598,72 €	8.606.598,72 €
Production losses/well/year [tons/year]:		81,69	49,01	44,11	31,76	28,59
Total production losses/year [tons/year]:		30.956,92	18.574,15	16.716,73	12.036,05	10.832,44
Total production losses/year [bbl/year]:		228.914,19	136.148,51	122.533,66	88.224,24	79.401,81
Total oil production/year (old) [tons/year]:		165.557,13	149.001,42	134.101,27	120.691,15	108.622,03
Total oil production/year (old) [bbl/year]:		1.213.533,75	1.092.180,38	982.962,34	884.666,10	796.199,49
Production increase/year [bbl/year]:		75.638,06	136.148,51	122.533,66	132.336,35	119.102,72
Total oil production/year (new) [bbl/year]:		1.289.171,81	1.228.328,89	1.105.496,00	1.017.002,46	915.302,21
Revenues / year [Euro/year]:		58.012.731,56 €	55.274.798,94 €	49.747.319,94 €	45.765.110,81 €	41.188.598,54 €
Savings due to reduced interventions/year[Euro/year]:		2.151.649,68 €	4.303.298,36 €	4.303.298,36 €	5.163.959,23 €	5.163.959,23 €

The requested data to estimate the annual production increases, annual revenues and the intervention cost savings of the first year are the:

- **annual intervention costs per well for 7.5 interventions per year**
- **annual intervention costs for 7.5 interventions per well for the 5% of the wells which are completely exchanged**
- **annual intervention costs for 10 interventions per well for the 5% of the wells (old scenario)**
- **annual savings due to the reduced number of interventions from 10 to 7.5**
- **annual production losses per well for 6 interventions per year**
- **annual production losses of the 5% of the wells**
- **annual oil production of the 5% of the wells**
- **annual oil production of the old scenario of the 5% of the wells**
- **annual production increase**
- **annual revenue**

The calculation procedure for these data is the same as for the best case. The only difference is the percentage of equipped wells per year.

The calculation table of the annual production increases, the annual revenues and the intervention cost savings for the 5% of the wells which are equipped in the second year is displayed on Tab. 5-52. These wells are equipped with new sucker rod strings in the second year. Therefore the total intervention costs per year do not decrease earlier, and so in the first year of the calculation model there are no savings due to reduced interventions and no production increase for these 5% of the wells.

Tab. 5-52 Annual production increase, annual revenues and annual intervention cost savings of the 5% of the wells equipped with new sucker rod strings in the second year

Sucker rod string (Worst case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	5,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	17.033,78 €	11.355,85 €	11.355,85 €	9.084,68 €
Total intervention costs/year (new) [Euro/year]:		8.606.598,72 €	6.454.949,04 €	4.303.299,36 €	4.303.299,36 €	3.442.639,49 €
Total intervention costs/year (old) [Euro/year]:		8.606.598,72 €	8.606.598,72 €	8.606.598,72 €	8.606.598,72 €	8.606.598,72 €
Production losses/well/year [tons/year]:		108,92	73,52	44,11	39,70	28,59
Total production losses/year [tons/year]:		41275,89	27081,22	16716,73	15045,06	10832,44
Total production losses/year [bbl/year]:		302552,75	204222,77	122533,66	110280,30	79401,81
Total oil production/year (old) [tons/year]:		165557,13	149001,42	134101,27	120691,15	108622,03
Total oil production/year (old) [bbl/year]:		1213533,75	1092180,38	982962,34	884666,10	796199,49
Production increase/year [bbl/year]:		0,00	68074,28	122533,66	110280,30	119102,72
Total oil production/year (new) [bbl/year]:		1213533,75	1160254,63	1105496,00	994946,40	915302,21
Revenues / year [Euro/year]:		54.609.018,75 €	52.211.458,41 €	49.747.319,94 €	44.772.587,85 €	41.188.599,54 €
Savings due to reduced interventions/year[Euro/year]:		- €	2.151.649,68 €	4.303.299,36 €	4.303.299,36 €	5.163.959,23 €

The tables which show the calculation of the annual production increases, the annual revenues and the annual intervention cost savings for the wells which are completely equipped in the third, the fourth and the fifth year can be seen on Tab. 10-27, Tab. 10-28 and Tab. 10-29 in the Appendix. The annual intervention frequency of theses wells remains at 10 until the installation of the new sucker rod strings takes place. For this reason these wells again show no savings and no production increase until the new sucker rod strings are installed.

Nearly 30% of all sucker rod pumped wells are completely equipped with new tubing material in the five years of the calculation model in the worst case of new sucker rod string installation. The intervention frequency for the rest of the wells stays at 10 and consequently no savings and no production increase are realized for these wells. The calculation table of the annual production increases, the annual revenues and the annual intervention cost savings for these wells can be seen on Tab. 10-30 in the Appendix.

In the end, the results of all the calculation tables have been added to obtain the **annual production,** the **annual revenues** and the **annual savings** for the entire 7,579 sucker rod pumped wells. These sums are displayed on Tab. 5-53.

Tab. 5-53 Annual production, annual revenues and annual intervention cost savings of all 7,579 sucker rod pumped wells in the worst case

Sucker rod string (Worst case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	100%	of the wells:				
Total oil production/year (new) [bbl/year]:		24.346.313,06	22.047.830,27	19.965.580,90	18.123.415,23	16.469.877,33
Revenues / year [Euro/year]:		1.095.584.087,01 €	992.152.362,09 €	898.451,140,64 €	815.553.685,17 €	741.144.479,78 €
Savings due to reduced interventions/year [Euro/year]:		2.151.648,68 €	6.454.946,04 €	10.758.240,39 €	16.702.087,49 €	23.880.168,47 €

In the worst case of new sucker rod strings installation the **annual production** and the **annual revenues** are also higher than on Tab. 5-5, which shows the annual oil productions and annual revenues for an intervention frequency of 10 interventions per year. Concerning this case less sucker rod pumped wells are completely exchanged with new sucker rod strings than in the best case. For this reason the annual production decline of ten percent is also reduced, but not as significantly as in the best case. The **annual savings due to a reduced number of interventions** are also lower than in the best case due to the lower number of newly equipped wells.

5.5.4 Production increase and intervention cost savings for the realistic case

Concerning the most realistic case of the new sucker rod string installation the actual exchange rate of 10% will be maintained again and an additional 10% of the sucker rod pumped wells are completely equipped in the first three years and then another 15% are completely equipped in the following years. The assumed intervention frequency development due to the installation of new sucker rod string material in the most realistic case can be seen on Tab. 5-42.

The annual production increase, the annual revenues and the annual intervention cost savings due to a reduced number of interventions have been estimated after the same procedure which has been applied for the best and the worst case. The significant difference is again the percentage of completely equipped wells per year and consequently the number of wells which are affected by the reduced intervention frequency. The calculation table of the 10% of the wells which are equipped with new sucker rod strings in the first year is shown on Tab. 5-54. The structure of this table is the same as for the best and the worst cases.

Tab. 5-54 Annual revenues and annual intervention cost savings of the 10% of the wells equipped with new sucker rod strings in the first year

Sucker rod string (Most realistic case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	10,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		17.033,78 €	11.355,85 €	11.355,85 €	9.084,68 €	9.084,68 €
Total intervention costs/year (new) [Euro/year]:		12.909.898,07 €	8.606.590,72 €	8.606.590,72 €	6.885.278,97 €	6.885.278,97 €
Total intervention costs/year (old) [Euro/year]:		17.213.197,43 €	17.213.197,43 €	17.213.197,43 €	17.213.197,43 €	17.213.197,43 €
Production losses/well/year [tons/year]:		81,69	49,01	44,11	31,76	28,59
Total production losses/year [tons/year]:		61913,83	37148,30	33433,47	24072,10	21664,89
Total production losses/year [bbl/year]:		453828,38	272297,03	245067,32	176448,47	158803,62
Total oil production/year (old) [tons/year]:		331116,26	298002,83	268202,55	241382,29	217244,06
Total oil production/year (old) [bbl/year]:		2427087,50	2184380,75	1965924,68	1769332,21	1592398,99
Production increase/year [bbl/year]:		151276,13	272297,03	245067,32	264677,71	238205,44
Total oil production/year (new) [bbl/year]:		2578363,63	2456677,78	2210992,00	2034004,92	1830604,42
Revenues / year [Euro/year]:		116.025.463,13 €	110.549.599,88 €	99.494.639,89 €	91.530.221,21 €	82.377.199,09 €
Savings due to reduced interventions/year [Euro/year]:		4.303.299,36 €	8.606.590,72 €	8.606.590,72 €	10.327.918,46 €	10.327.918,46 €

The next step is the calculation of all the data which are listed on the table. These data have been evaluated in the same way as for the best case and the worst case, but as already mentioned for a different number of equipped wells per year. The procedure of these calculations has already been explained in detail in section 5.3.2 and in section 5.4.2.

The calculation table of the annual production increase, the annual revenues and the annual savings due to the reduced number of interventions for the 10 % of the wells which are equipped with new tubing material in the second year is represented on Tab. 5-55. As can also be noticed in the best and worst cases, the total intervention costs per year do not decrease in the first year, because no new sucker rod strings are installed in the first year for this 10% of the wells. For this reason, the number of interventions per well is still at 10 in the first year. Consequently, there are also no savings due to reduced interventions and no production increase for these 10 % of the wells in the first year of the calculation model.

Tab. 5-55 Annual revenues and annual intervention cost savings of the 10% of the wells equipped with new sucker rod strings in the second year

Sucker rod string (Most realistic case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	10,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	17.033,78 €	11.355,85 €	11.355,85 €	9.084,68 €
Total intervention costs/year (new) [Euro/year]:		17.213.197,43 €	12.909.898,07 €	8.606.598,72 €	8.606.598,72 €	6.885.278,97 €
Total intervention costs/year (old) [Euro/year]:		17.213.197,43 €	17.213.197,43 €	17.213.197,43 €	17.213.197,43 €	17.213.197,43 €
Production losses/well/year [tons/year]:		108,92	73,52	44,11	39,70	28,59
Total production losses/year [tons/year]:		82551,77	55722,65	33433,47	30090,12	21664,89
Total production losses/year [bbl/year]:		605104,50	408445,54	245067,32	220560,59	158803,62
Total oil production/year (old) [tons/year]:		331116,26	298002,83	268202,55	241382,29	217244,06
Total oil production/year (old) [bbl/year]:		2427087,50	2184380,75	1965924,68	1769332,21	1592398,99
Production increase/year [bbl/year]:		0,00	136148,51	245067,32	220560,59	238205,44
Total oil production/year (new) [bbl/year]:		2427087,50	2320509,26	2210992,00	1989892,80	1830604,42
Revenues / year [Euro/year]:		109.218.937,50 €	104.422.916,81 €	99.494.639,89 €	89.545.175,90 €	82.377.199,09 €
Savings due to reduced interventions/year[Euro/year]:		- €	4.303.299,36 €	8.606.598,72 €	8.606.598,72 €	10.327.918,46 €

The calculation tables of the annual production increases, the annual revenues and the annual intervention cost savings for the wells which are completely equipped in the third, fourth and fifth years are represented on Tab. 10-31, Tab. 10-32 and Tab. 10-33 in the Appendix. Concerning these wells the annual intervention frequency per well stays at 10 until the installation of the new sucker rod strings has taken place. Consequently these wells show again no savings and no production increase until the new sucker rod strings are installed.

Forty percent of the sucker rod pumped wells are not installed with new sucker rod strings in the most realistic case during the time period of the calculation model. The intervention frequency of these wells always stays at 10 and consequently no savings and no production increase are realized for these wells. The calculation table of the annual production increases, the annual revenues and the annual intervention cost savings for these wells is shown on Tab. 10-34 in the Appendix. Finally the results of all the particular calculation tables have been summed up again to receive the **annual production,** the **annual revenues** and the **annual savings** for all of the 7,579 sucker rod pumped wells. Theses results are shown on Tab. 5-56.

Tab. 5-56 Annual production, annual revenues and annual intervention cost savings of all 7,579 sucker rod pumped wells in the most realistic case

Sucker rod string (Most realistic case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	100%	of the wells:				
Total oil production/year (new) [bbl/year]:		24.270.675,00	21.843.607,50	19.659.246,75	17.693.322,08	15.923.989,87
Revenues / year [Euro/year]:		1.098.907.800,63 €	1.001.342.386,69 €	912.236.177,53 €	835.404.138,78 €	767.049.321,10 €
Savings due to reduced interventions/year[Euro/year]:		4.303.299,36 €	12.909.898,07 €	21.516.496,79 €	33.996.064,92 €	48.627.282,74 €

The results are characterized by the same facts that could be noticed for the employment of the corrosion inhibitor and the installation of new tubing materials.

That means that the annual oil production and revenues generated by the production are again higher than on Tab. 5-5, which displays the annual oil productions and annual revenues for an intervention frequency of 10 interventions per well per year. The actual production decline of 10% has been reduced again over the years of the calculation model. The reduction of this decline is lower than in the best case, but higher than in the worst one. For this reason, the annual oil productions, the annual revenues and the savings also lie between the results of the assumed best case and the assumed worst case.

The total annual oil productions and the annual production increase in absolute numbers and in percent are represented on Fig. 10-7, Fig. 10-8 and Fig. 10-9 in the Appendix.

5.5.5 Difference in net present value for the best, worst and realistic case

The total savings due to the installation of new sucker rod strings have again be calculated as the difference of two different net present values. The first one is the net present value which considers a reduced number of interventions per well per year. The second one is the net present value of the future scenario without any changes which considers no installation of new sucker rod strings and therefore no reduction of the actual intervention frequency of 10 interventions per well per year. These total savings are the differences between the net present values of both scenarios and must not be mistaken with the savings due a reduced number of interventions. The annual cash flows considering the installation of new sucker rod strings have been evaluated in the following way:

Annual revenues (generated by the oil production)

\+ Annual savings (due to reduced interventions)

\- Annual total sucker rod string and pump repair costs

= Annual cash flows

The next step is the calculation of the annual cash flow for the scenario which considers no installation of new sucker rod strings. In this scenario, as already mentioned, the intervention frequency has not been decreased. Consequently, no annual savings are realized, but also no additional investment costs have to be expended. Therefore, the annual revenues equal the annual cash flows.

Tab. 5-57 displays the calculation of the difference in net present value for the best case of the installation of new sucker rod strings. The calculation tables of the difference in net present value for the worst case and the most realistic case for the installation of new sucker rod strings are displayed on Tab. 10-35 and Tab. 10-36 in the Appendix.

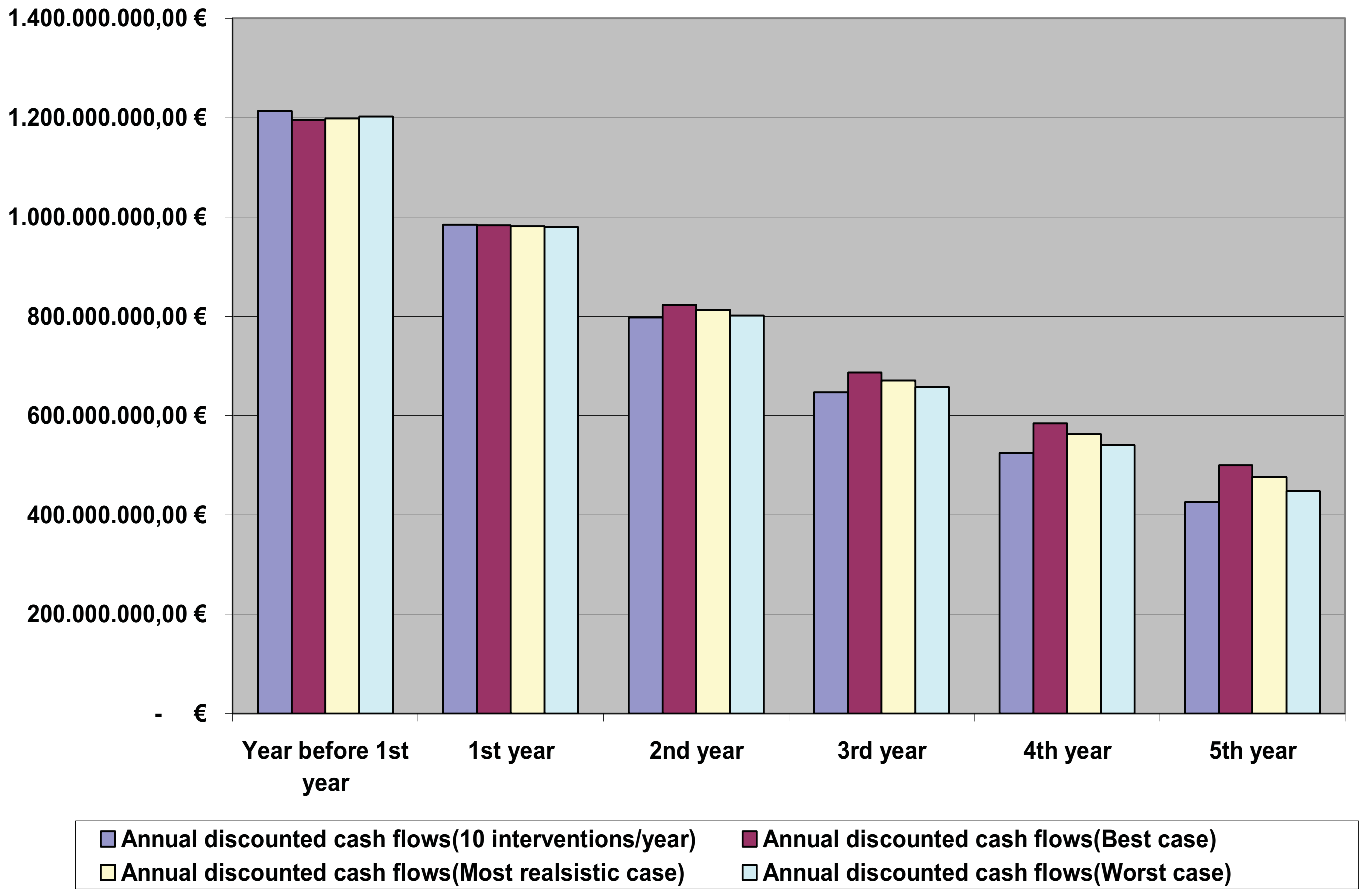
Tab. 5-57 Difference in net present value for the best case

Sucker rod string (Best case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Annual revenues due to the oil production [Euro/year]:	1.213.533.750,00 €	1.102.391.513,44 €	1.010.532.411,28 €	926.021.214,42 €	853.765.807,43 €	788.934.445,07 €
Annual savings due to reduced interventions [Euro/year]:		6.454.946,04 €	19.364.847,11 €	32.274.745,18 €	49.918.272,55 €	69.713.449,59 €
Sucker rod string costs [Euro/year]:	17.931.914,00 €	16.855.999,16 €	15.780.084,32 €	18.290.352,28 €	16.855.999,16 €	15.421.446,04 €
Annual cash flow(Best case)[Euro/year]:	1.195.601.836,00 €	1.091.990.463,31 €	1.014.117.174,07 €	940.005.407,32 €	886.828.080,82 €	843.226.448,22 €
Annual discounted cash flow(10interventions/year)[Euro/year]:	1.213.533.750,00 €	983.946.283,78 €	797.794.284,15 €	646.860.230,39 €	524.481.267,88 €	425.255.082,07 €
Annual discounted cash flow(Best case)[Euro/year]:	1.195.601.836,00 €	983.775.192,17 €	822.080.248,41 €	687.323.852,21 €	584.181.125,58 €	500.413.856,14 €
Net present value (10 interventions per year)[Euro/year]:		2.197.480.033,78 €	2.995.274.317,93 €	3.642.134.548,32 €	4.166.615.816,21 €	4.591.870.898,28 €
Net present value (Best case)[Euro/year]:		2.179.377.028,17 €	3.002.457.276,58 €	3.689.781.128,80 €	4.273.962.254,37 €	4.774.376.110,52 €
Difference in net present value [Euro/year]:	- 17.931.914,00 €	- 18.103.005,61 €	7.182.958,66 €	47.646.580,47 €	107.346.438,17 €	182.505.212,24 €

First, the annual cash flows for the assumed best case of the installation of new sucker rod strings have been calculated. Then, the cash flows for the case which considers no installation of new sucker rod strings have been evaluated. Afterwards, these cash flows have been discounted to consider the time value of the money.

Fig. 5-8 represents the discounted cash flows for the best, worst, most realistic cases and the case without any changes which is characterized by 10 interventions per well per year.

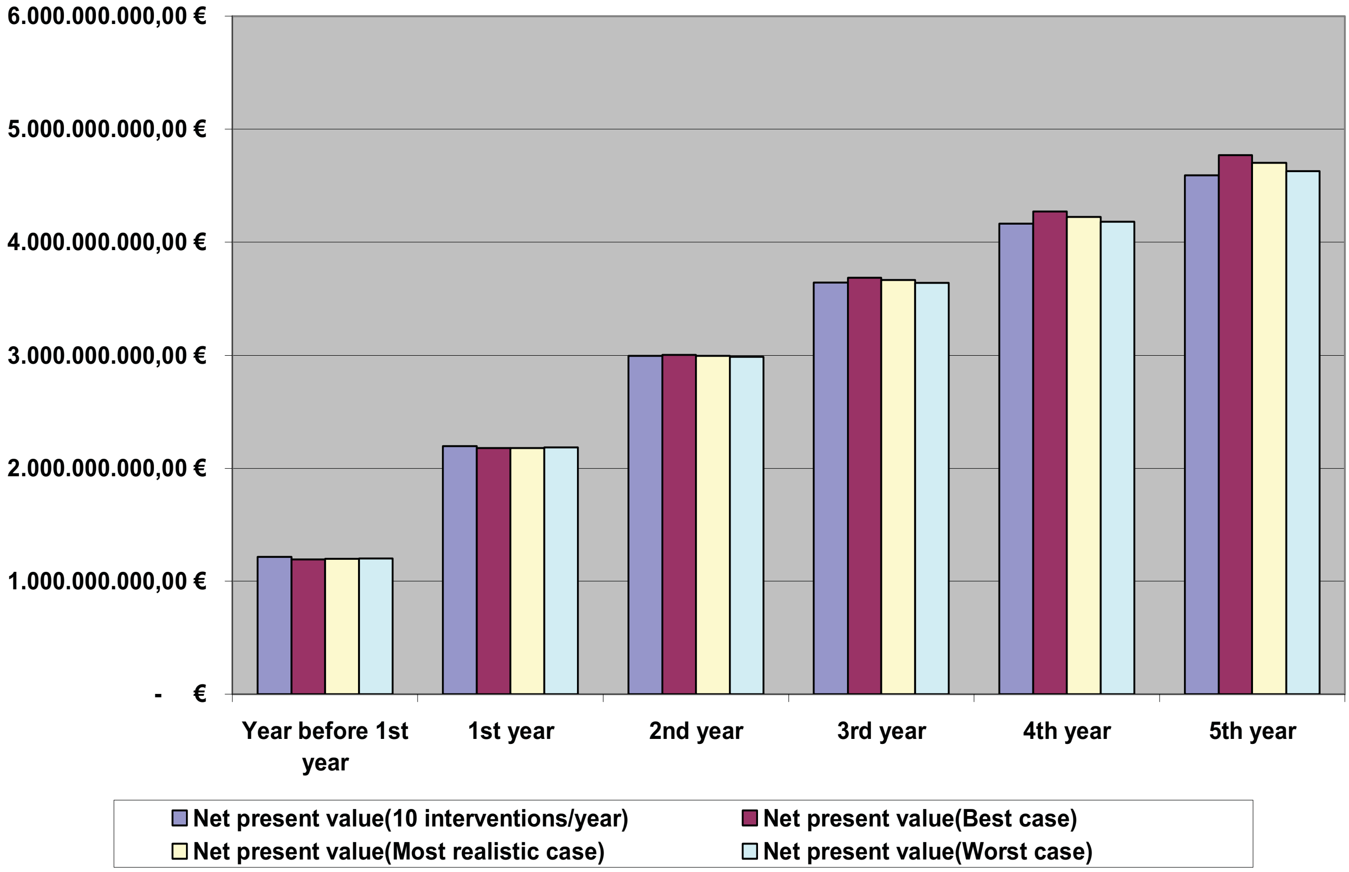
Fig. 5-8 Discounted cash flows for sucker rod string material scenarios



As can be observed on Fig. 5-8 the discounted cash flows in the best, worst and most realistic cases are higher than in the scenario, which considers no installation of new sucker rod strings. The cause for this is that the annual savings due to the reduced intervention frequency which are caused by the installation of the new sucker rod strings are much higher than the annual costs for these new sucker rod string materials. For this reason huge potential savings could be enabled by installing new sucker rod strings. The annual savings due to a reduced intervention frequency and the annual costs for the sucker rod string materials are represented in the third and fourth row of Tab. 5-57. The discounted cash flow of the most realistic case lies between the discounted cash flows of the best and the worst cases.

The next step is the calculation of the net present values for the best, the worst and the most realistic case and for the case without any sucker rod string installation, which is characterized by an intervention frequency of 10. These net present values are the sum of the discounted cash flows. Fig. 5-9 represents all these estimated net present values.

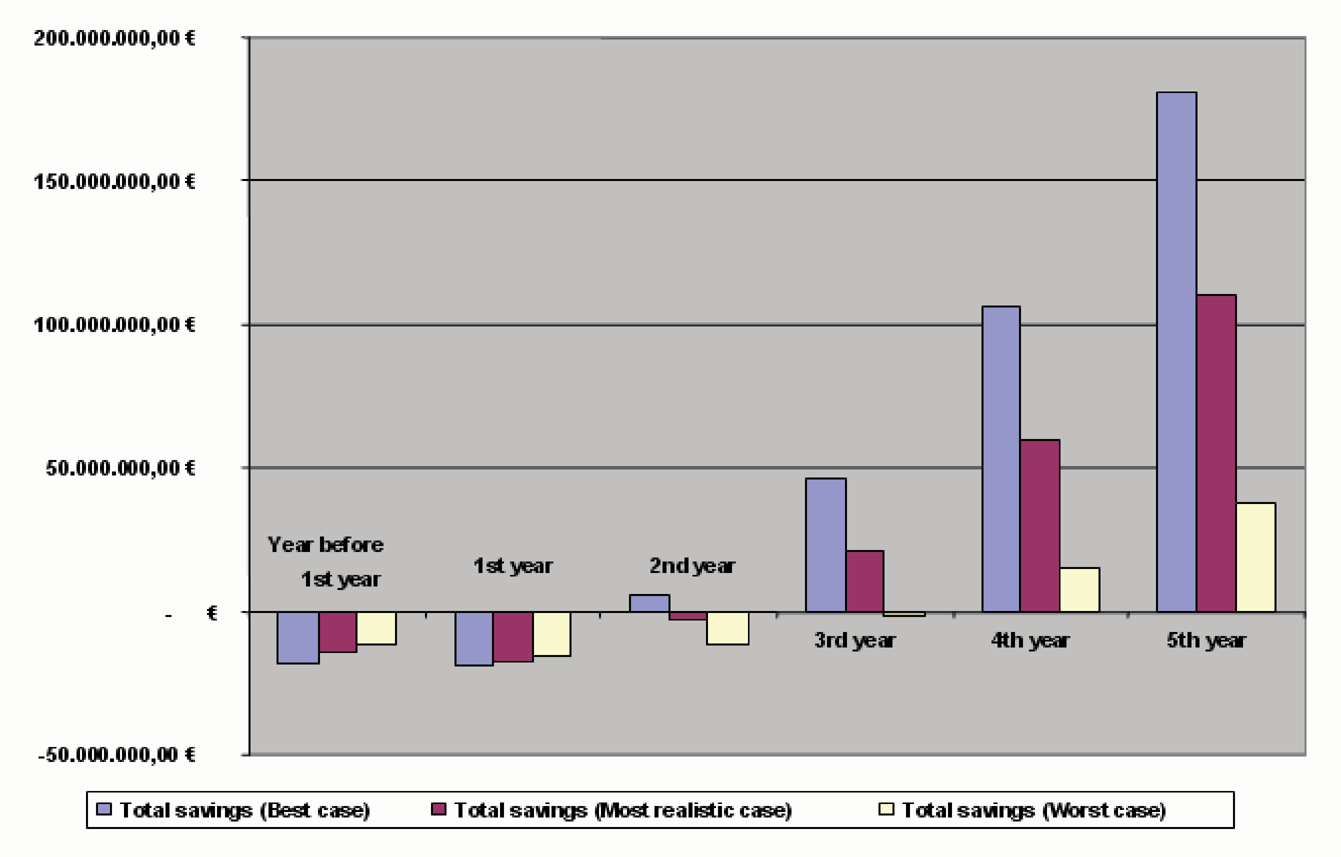
Fig. 5-9 Net present values for different new sucker rod string material scenarios



Finally, the total savings due to the installation of new sucker rod string material have been calculated. As already mentioned, these total savings are the differences of net present values of the best, worst and or realistic case and the net present value of the case without any changes. The difference of the net present values in the year before the first installation is the costs for the new sucker rod string material in this year. This fact can be seen on Tab. 5-57. In the year before the first installation just the purchase of the new sucker rod string material is carried out, but no sucker rod pumped wells are completely equipped in this year. For this reason the intervention frequency is not reduced and no savings are realized in the year of the first investment. Since also no discounting takes place in this year the difference of the net present values equals the costs for the sucker rod string material. The cumulated savings or differences of the net present values are displayed on Fig. 5-10.

The payout period is 1.75 years in the best case, 3.1 years in the worst case and 2.11 years in the most realistic case.

Fig. 5-10 Total savings for different new sucker rod string material scenarios



5.6 Combination scenario of the most realistic cases

The last scenario, which has been calculated to estimate the total savings and production increase due to the employment of new materials and new technologies, is the combination of the most realistic cases of the corrosion inhibitor employment, the installation of new tubing materials and the installation of new sucker rod strings. The newly installed equipment is exactly the same as in the most realistic cases of the previously described planned actions. Concerning the preceding calculations, an intervention frequency reduction has only been assumed for those wells which have been affected by the employment of new technologies or the installation of new materials. But, in this case, the intervention frequency reduction has been assumed for the entire 7,579 sucker rod pumped wells in Romania. The reason for this procedure is that a different number of wells are affected by the different planned actions in the assumed most realistic cases as can be observed on Tab. 5-58. For example in the first year of installation 1,000 wells are supposed to be inhibited but only 10% of the wells – which makes up about 750 wells – are equipped with new materials. Therefore in the first year of installation there are wells which are affected by several new technological updates, wells which are just treated with corrosion inhibitor and wells which are not affected by any new technological updates. Consequently the intervention frequency reduction cannot be assumed for a certain number of wells. Tab. 5-58 shows the percentage of wells which are affected by the corrosion inhibitor employment, the installation of new tubing material and the installation of new sucker rod strings in the combination scenario. The percentages of newly equipped wells are exactly the same as in the most realistic cases of the other planned actions. But, due to the fact that the intervention frequency is decreased, the actual exchange rate of 10%, which is standard in Romania at the moment, will also decline from year to year. This fact will be explained more precisely in the following chapter. Tab. 5-58 also displays the assumed intervention frequency development for the 7,579 sucker rod pumped wells. As can be seen in the second row of Tab. 5-58, the average intervention frequency in this combination scenario is assumed with eight interventions per well per year in the first year of installation. This average intervention frequency is assumed to decrease during the time period of the calculation model until it reaches two interventions per well per year in the fifth year of the calculation model.

Tab. 5-58 Development of the intervention frequencies due to new technology employments in the combination scenario and number/percentage of equipped wells

Combination	1st year	2nd year	3rd year	4th year	5th year
Number of interventions/well/year:	8,0	5,5	3,0	2,5	2,0
Corrosion Inhibitor:					
Inhibitor treatment pumps/year:	1000	2000	2000	0	0
Tubing:					
Percentage of stepwise equip. wells:	8,0%	5,5%	3,0%	2,5%	2,0%
Percentage of completely equip. wells:	10%	10%	10%	15%	15%
Sucker rod string:					
Percentage of stepwise equip. wells:	8,0%	5,5%	3,0%	2,5%	2,0%
Percentage of completely equip. wells:	10%	10%	10%	15%	15%

5.6.1 Costs for the combination scenario of the most realistic cases

The costs for the combination scenario include the **corrosion inhibitor employment costs**, the **total tubing material costs** and the **total sucker rod string material costs** concerning the most realistic cases.

The **corrosion inhibitor employment costs** concerning the combination scenario are exactly the same which have already been described in detail for the most realistic case in section 5.3.1. The calculation table for the corrosion inhibitor employment for the combination scenario is displayed on Tab. 5-12.

The **total tubing material costs** and the **total sucker rod string material costs** in this case differ a little bit from the total tubing costs which are shown for the most realistic case on Tab. 5-29 and the sucker rod string material costs for the most realistic case which are displayed on Tab. 5-46. The percentage of completely exchanged wells is the same for both scenarios, and so the total tubing costs and the total sucker rod string material costs for the completely equipped wells are the same.

But the percentage of tubing material and sucker rods which are replaced in stages as has been standard in Romania until now is slightly different. As already described the assumed intervention frequency reduction in this case refers to the entire 7,597 sucker rod pumped wells in Romania and not only to the completely exchanged wells as in the other scenarios. Concerning the first year of installation the intervention frequency is assumed at eight interventions per well per year. An average well includes about 100 tubings and 100 sucker rods. If a failure occurs, the destroyed tubing and sucker rod are exchanged by carrying out an intervention. Consequently, considering 8 interventions per well per year in the first year of installation, eight percent of the tubing and sucker rod string material are exchanged stepwise. This fact can be observed on Tab. 5-59 and Tab. 5-60. These tables show the total tubing material costs and the total sucker rod string material costs for the combination scenario.

Tab. 5-59 Calculation table of total tubing material costs for the combination scenario

Tubing costs (Combination)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Percentage of wells which are stepwise exchanged:		8,0%	5,5%	3,0%	2,5%	2,0%
Annual tubing material costs [Euro/year]:	11.216.920,00 €	7.711.999,74 €	4.206.345,00 €	3.505.287,50 €	2.804.230,00 €	2.804.230,00 €
Additional annual exchange rate		10,0%	10,0%	10,0%	15,0%	15,0%
Annual tubing material costs [Euro/year]:	14.028.729,00 €	14.028.729,00 €	14.028.729,00 €	21.043.093,50 €	21.043.093,50 €	21.043.093,50 €
Annual lining process costs [Euro/year]:	3.754.030,28 €	3.754.030,28 €	3.754.030,28 €	5.631.045,42 €	5.631.045,42 €	5.631.045,42 €
Annual wall thickness survey costs [Euro/year]:		2.273.700,00 €	2.273.700,00 €	2.273.700,00 €	3.410.550,00 €	3.410.550,00 €
Total annual exchange rate:		18,0%	15,5%	13,0%	17,5%	17,0%
Total annual tubing costs [Euro/year]:	28.999.679,28 €	27.768.459,02 €	24.262.804,28 €	32.453.126,42 €	32.888.918,92 €	32.888.918,92 €

Tab. 5-60 Calculation table of sucker rod string costs for the combination scenario

Sucker rod string costs (Combination)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Percentage of wells which are stepwise exchanged:		8,0%	5,5%	3,0%	2,5%	2,0%
Annual sucker rod string material costs for 10% [Euro/year]:	5.868.177,60 €	4.034.251,75 €	2.200.941,60 €	1.834.118,00 €	1.467.294,40 €	1.467.294,40 €
Additional annual exchange rate:		10,0%	10,0%	10,0%	15,0%	15,0%
Additional annual sucker rod string material costs [Euro/year]:	7.337.472,00 €	7.337.472,00 €	7.337.472,00 €	11.004.708,00 €	11.004.708,00 €	11.004.708,00 €
Total annual exchange rate:		18,0%	15,5%	13,0%	17,5%	17,0%
Total annual sucker rod string material costs [Euro/year]:	13.205.649,60 €	11.371.723,75 €	9.537.413,60 €	12.838.826,00 €	12.472.002,40 €	12.472.002,40 €

5.6.2 Production increase and intervention cost savings for the combination

In the last two chapters the intervention frequency decrease caused by the new technology employments and the costs for these new technologies and materials have been described. On the basis of these data the annual production increase, annual revenues and annual intervention costs savings due to a reduced number of interventions for the combination case have been estimated.

In the most realistic case of new corrosion inhibitor employment, 1,000 inhibitor treatment pumps are installed in the first year, 2,000 are installed in the second and 2,000 are installed in the third year.

Concerning the most realistic cases of the new tubing material employment and new sucker rod strings installation, 10% of the wells are equipped in the first three years and then 15% are additionally equipped in the fourth and fifth year of the calculation model.

Tab. 5-61 represents the calculation table the annual production increase, annual revenues and annual intervention costs savings due to a reduced number of interventions for the combination scenario.

Tab. 5-61 Annual production increase, annual revenues and annual intervention cost savings of the entire 7,579 wells

Combination scenario	1st year	2nd year	3rd year	4th year	5th year
Number of intervention per well per year:	8,0	5,5	3,0	2,5	2,0
Intervention costs/well/year [Euro/year]:	18.169,36 €	12.492,03 €	6.813,51 €	5.677,93 €	4.542,34 €
Total intervention costs/year (new) [Euro/year]:	137.705.579,44 €	94.677.094,30 €	51.639.592,29 €	43.032.993,58 €	34.426.394,86 €
Total intervention costs/year (old) [Euro/year]:	172.131.974,30 €	172.131.974,30 €	172.131.974,30 €	172.131.974,30 €	172.131.974,30 €
Production losses/well/year [tons/year]:	87,14	53,92	26,47	19,85	14,29
Total production losses/year [tons/year]:	660.414,19	408.650,74	200.600,81	150.450,61	108.324,44
Total production losses/year [bbl/year]:	4.840.836,00	2.995.409,91	1.470.403,94	1.102.802,95	794.018,12
Total oil production/year (old) [tons/year]:	3.311.142,56	2.980.028,31	2.682.025,48	2.413.822,93	2.172.440,64
Total oil production/year (old) [bbl/year]:	24.270.675,00	21.843.607,50	19.659.246,75	17.693.322,08	15.923.989,87
Production increase/year [bbl/year]:	1.210.209,00	2.450.530,59	3.430.942,52	3.308.408,85	3.176.072,50
Total oil production/year (new) [bbl/year]:	25.480.884,00	24.294.138,09	23.090.189,27	21.001.730,93	19.100.062,37
Revenues / year [Euro/year]:	1.146.639.780,00 €	1.093.236.213,89 €	1.039.058.516,93 €	945.077.891,79 €	859.502.806,52 €
Savings due to reduced interventions/year[Euro/year]:	34.426.394,86 €	77.454.880,00 €	120.492.382,01 €	129.098.980,73 €	137.705.579,44 €

The calculation of the following data was necessary to evaluate the annual production increase, the annual revenues generated by the production and the annual intervention costs savings due to a reduced number of interventions for the combination scenario in the first year:

- **annual intervention costs per well for eight interventions per year**
- **annual intervention costs for eight interventions per well for the entire 7,579 sucker rod pumped wells**
- **annual intervention costs for 10 interventions per well for the entire 7,579 sucker rod pumped wells**
- **annual savings due to the reduced number of interventions from 10 to 8**
- **annual production losses per well for eight interventions per year**
- **annual production losses of the entire 7,579 sucker rod pumped wells**

- **annual oil production of the entire 7,579 sucker rod pumped wells**
- **annual oil production of the old scenario of the entire 7,579 sucker rod pumped wells**
- **annual production increase**
- **annual revenue**

The calculation of these data has been carried out in a similar way as has been done for the other planned actions. The significant differences are the assumed annual intervention frequencies and the number of wells which are affected by new technology employments. The calculation procedure of these data has been described in detail in section 5.3.2 and in section 5.4.2.

For the following years, the requested data is calculated in the same way but for a different intervention frequency as it can be seen in the second row of Tab. 5-61.

Considering the combination scenario, the annual oil productions and revenues generated by the production are significantly higher than in the other previously calculated planned actions. They are also, of course, higher than on Tab. 5-5, which represents the annual oil productions and annual revenues for an intervention frequency of 10 interventions per year. In this case the actual production decline of 10% per year has been reduced more significantly than in all other estimated future scenarios. Consequently, the savings due to the reduced intervention frequency are also eminently higher than in the other planned future actions.

The total annual oil productions and the annual production increase due to the new technology employments – in absolute numbers and in percent – are displayed on Fig. 10-10, Fig. 10-11 and Fig. 10-12 in the Appendix.

5.6.3 Difference in net present value for the combination scenario

The total savings caused by the combination of the technology employments have again been evaluated as the difference of two net present values. The first one is the net present value which considers a reduced intervention frequency per well per year. The second one is the net present value of the future scenario without any changes which considers no employment of new technologies and materials and therefore no reduction of the actual intervention frequency of 10 interventions per well per year. The annual cash flows considering the combination of the new technology employments have been calculated according to the following procedure:

Annual revenues (generated by the oil production)

\+ Annual savings (due to reduced interventions)

\- Annual capex of corrosion inhibitor

\- Annual opex of corrosion inhibitor

\- Annual total tubing costs

\- Annual total sucker rod string and pump repair costs

= Annual cash flows

According to this equation, the annual cash flows for the scenario which considers no employment of new technologies have been calculated. As already mentioned, in this scenario, the intervention frequency has not been reduced. Therefore no savings can be realized, but also no additional investment costs have to be expended. Therefore the annual revenues equal the annual cash flows. The calculation of the difference in net present value for the combination scenario is represented on Tab. 5-62.

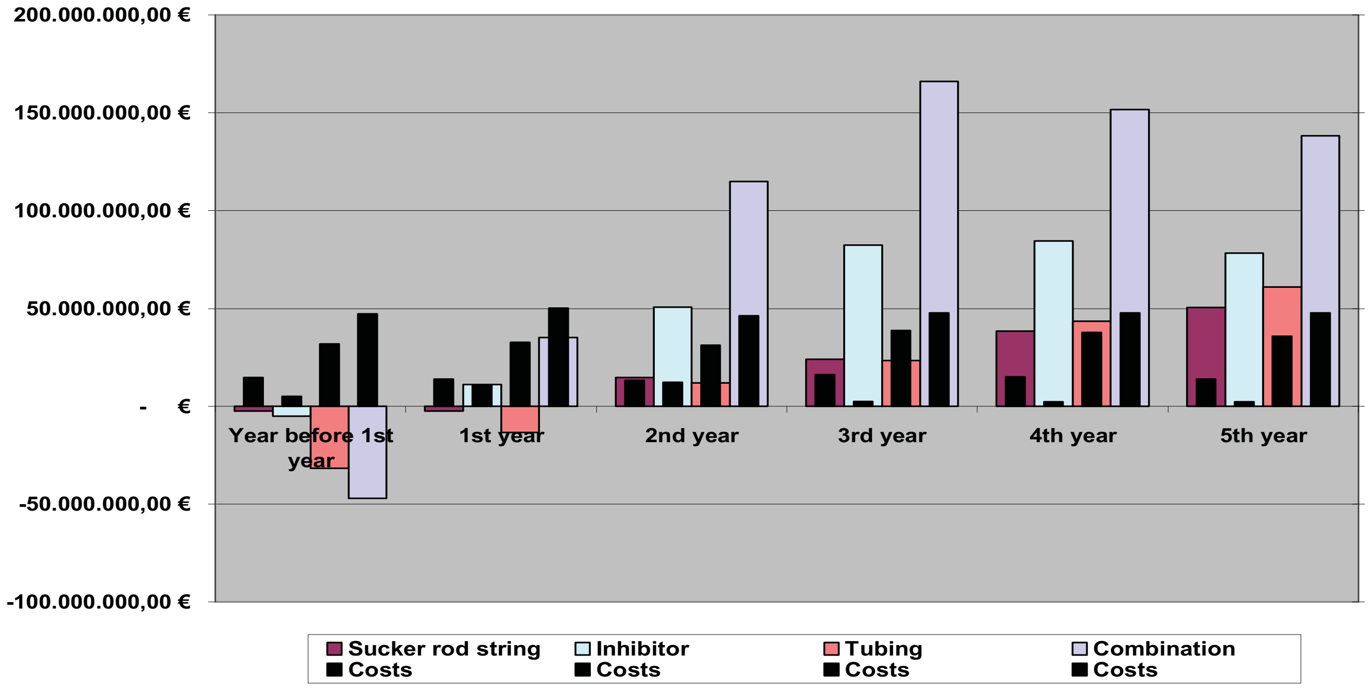
Tab. 5-62 Difference in net present value for the combination scenario

Combination	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Annual revenues due to the oil production [Euro/year]	1.213.533.750,00 €	1.146.638.780,00 €	1.093.236.213,88 €	1.039.058.516,83 €	965.077.891,78 €	859.502.006,52 €
Annual savings due to reduced interventions [Euro/year]		34.425.394,86 €	77.454.000,00 €	120.492.382,01 €	129.098.980,73 €	137.705.579,44 €
Annual capex [Euro/year]	5.000.000,00 €	10.000.000,00 €	10.000.000,00 €	- €	- €	- €
Annual opex [Euro/year]		882.530,45 €	2.303.313,94 €	2.360.883,51 €	2.274.828,18 €	2.197.181,74 €
Tubing costs [Euro/year]	20.999.679,28 €	27.768.459,02 €	24.262.004,78 €	32.453.128,42 €	32.888.918,92 €	32.888.918,92 €
Sucker rod string costs [Euro/year]	13.205.649,60 €	11.371.723,75 €	9.537.413,60 €	12.838.826,00 €	12.472.002,40 €	12.472.002,40 €
Annual cash flow(Combination case)[Euro/year]	1.166.328.421,12 €	1.131.043.461,64 €	1.124.587.562,07 €	1.111.898.253,01 €	1.026.541.327,04 €	949.650.302,90 €
Annual discounted cash flow(10interventions/year)[Euro/year]	1.213.533.750,00 €	983.946.283,78 €	797.794.284,15 €	646.860.230,39 €	524.481.267,89 €	425.255.082,07 €
Annual discounted cash flow(Combination case)[Euro/year]		1.018.958.073,55 €	912.740.493,52 €	813.010.419,48 €	676.214.568,36 €	563.571.233,45 €
Net present value (10 interventions per year)[Euro/year]		2.197.480.033,78 €	2.995.274.317,93 €	3.642.134.548,32 €	4.166.615.816,21 €	4.591.870.898,28 €
Net present value (Combination case)[Euro/year]		2.185.286.494,67 €	3.098.026.988,19 €	3.911.037.407,67 €	4.587.251.976,04 €	5.150.823.209,48 €
Difference in net present value [Euro/year]	- 47.205.328,88 €	- 12.193.539,12 €	102.752.670,26 €	268.902.859,35 €	420.636.159,83 €	558.952.311,20 €

At first the annual cash flows for the combination scenario and then the cash flows for the case which considers no new technology employments have been calculated. After that these cash flows have been discounted to consider the time value of the money as it can be observed in the ninth and tenth row of Tab. 5-62.

Concerning the discounted cash flow calculations of the other planned future actions the discounted cash flows have always been represented for the best, worst, most realistic case and the case without any changes. By contrast Fig. 5-11 shows the difference of the discounted cash flows of the combination scenario and the discounted cash flow of the case without any changes.

Fig. 5-11 Annual savings compared to annual costs for different planned future actions



These are the annual savings due to the combination of the technology employments. Fig. 5-11 also shows the annual savings of the most realistic cases of the other planned actions, which have been calculated in the same way. Due to the discounting of the cash flows, the differences between the discounted cash flows in the combination scenario decrease from year to year. In the most realistic case of the corrosion inhibitor employment, more significant higher annual savings are realized than in the other planned action, which have been calculated before. But even in the corrosion inhibitor scenario the difference of the discounted cash flows decreases from the fourth to the fifth year due to the discounting.

Additionally, the costs for all these future scenarios are displayed on Fig. 5-11. The costs for the corrosion inhibitor have a very conspicuous development in comparison to the other planned future actions, because they are significantly decreasing in the third year of installation. The reason for this different development is that all the corrosion inhibitor pumps are bought and installed until the third year. Consequently, from the third year forward, there are only the costs for the corrosion inhibitor itself and for the maintenance of the pumps, which are significantly lower than the costs of the pumps. This is also the reason why the employment of corrosion inhibitor realizes abundantly high savings in comparison to the new tubing and sucker rod string installation.

Then, the net present values for the combination scenario and the most realistic cases of the other future scenarios have been calculated. Fig. 5-12 shows the resulting calculated difference of the net present values of the combination scenario and the net present values of the case without any changes. These are the cumulated savings due to the combination of the new technology employment.

Fig. 5-12 Cumulated savings for different planned future actions

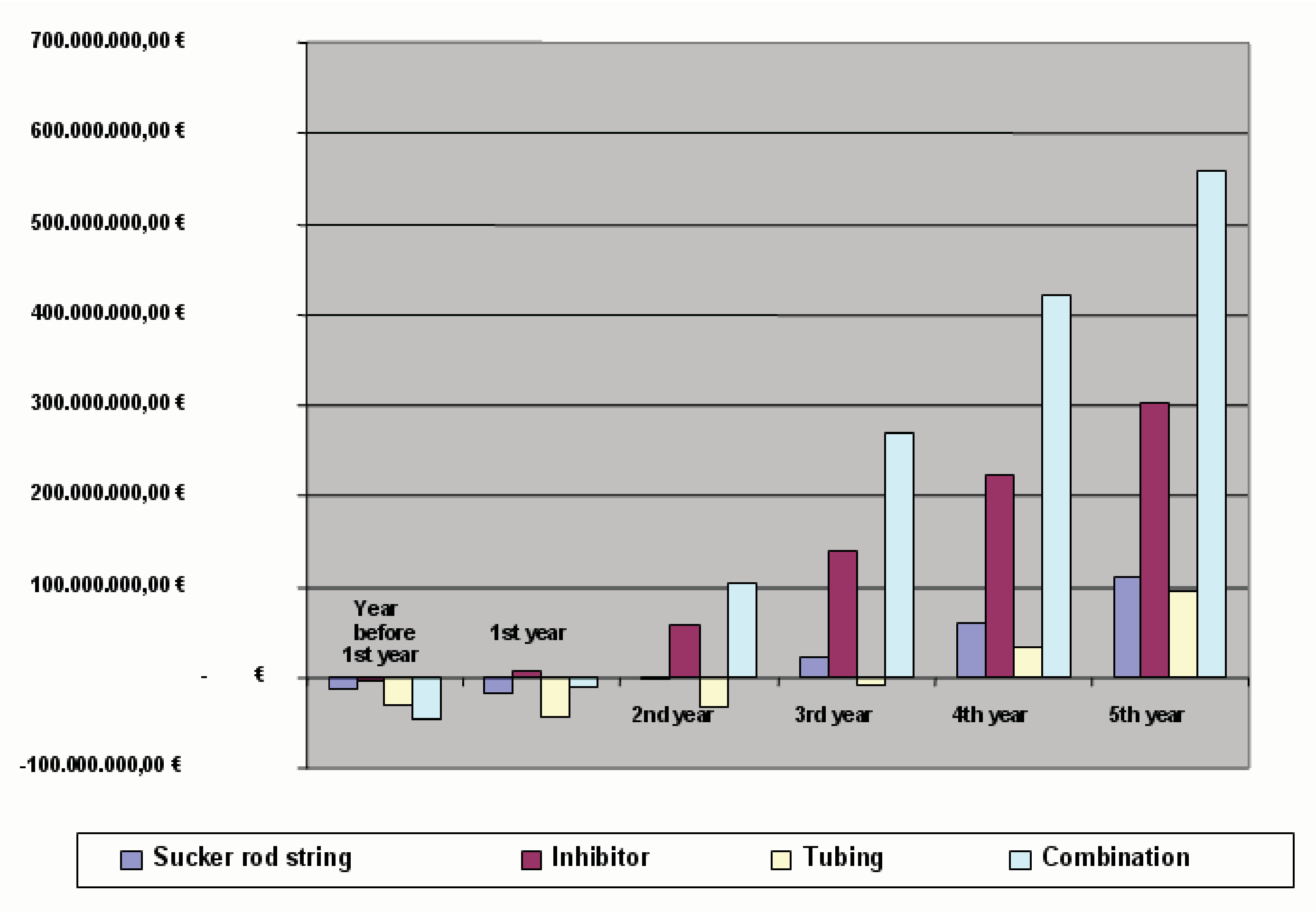


Fig. 5-12 also displays the cumulated savings of the most realistic cases of the other planned actions, which have been evaluated in the same way. As displayed on the table the corrosion inhibitor future scenario realizes the highest savings of the calculated single technologies. By the employment of corrosion inhibitor about 300 million Euros are estimated to be saved in the five years of the calculation model. Concerning the new tubing and new sucker rod string installation, the total savings are approximately 100 million Euros. In the combination scenario the cumulated savings are more than 550 million Euros. The payout period of the combination scenario equals 1.25 years. The payout periods of the most realistic cases have already been described in preceding chapters.

6 Results of the probabilistic and deterministic sensitivity analyses

After creating a calculation model to estimate the production increases and total savings due to the new technology employments, a Monte Carlo Simulation has been carried out. The aim of this simulation is to ascertain the influence of defined input parameters on certain output parameters of the calculation model. For these purposes the input parameters have been varied between before defined boundaries to consider their influences on the output parameters. As already described in detail in section 3.3.2 the Monte Carlo Simulation has been performed with the software @risk®, which is an add-in for Microsoft Excel®.

6.1 Input and output parameters of the Monte Carlo simulation

The following data of the calculation model has been defined as input parameters of the Monte Carlo Simulation:

- **oil price**
- **average costs of an intervention**
- **number of interventions per well per year**
- **J-55 steel tubing price**
- **price of the wall thickness survey**
- **lining process price**
- **inhibitor price**
- **inhibitor treatment pump price**
- **price of the sucker rod grade *D special* material**
- **rod guide price**
- **average costs for a sucker rod pump repair**

The values of these input parameters will certainly change during the five years of the calculation model. According to estimations of experts from OMV the defined input data are supposed to vary between the following boundaries, which are displayed on Tab. 6-1. The two columns from the right show the absolute values or percentages with which the input parameters are supposed to vary during the five years of the calculation model. For example the oil price has been assumed at $60 in the calculation model. As it can be observed in the second row of it has been varied between -$40 and +$40 during the Monte Carlo Simulation. That means that the crude oil price has been varied between \$20 and \$100 during the simulation. The current values of the defined input parameters can be seen on Tab. 5-9, Tab. 5-27 and on Tab. 5-44.

Tab. 6-1 Defined boundaries of the input parameters

Input parameter	Value of the input parameter	Absolute value or percentage to lower boundary	Absolute value or percentage to upper boundary
Oil price	\$60	-\$40	+\$40
Average costs for an intervention [Euro]	2,271.2	-20%	+20%
Assumed number of interventions in 5 years	21	-10%	+10%
J-55 steel tubing price [Euro/meter]	18.5	0%	+20%
Price of the wall thickness survey [Euro/meter]	3	0%	+10%
Lining process price [Euro/meter]	4.95	0%	+10%
Inhibitor price [Euro/liter]	2.5	0%	+10%
Inhibitor treatment skid price [Euro/skid]	5,000	0%	+5%
Price of the sucker rod grade D special material [Euro/piece]	48.4	0%	+20%
Rod guide price [Euro/piece]	12.1	0%	+5%
Average costs for a sucker rod pump repair [Euro/pump]	1,000	0%	+5%

As already mentioned in section 3.3.2, for the simulation of the calculation model, the Triangle Distribution was used. After defining the upper and lower boundaries of the input parameters, the output parameters of the Monte Carlo Simulation have been defined. These output parameters are the:

- **accumulated savings due to the employment of corrosion inhibitor after a time period of five years**
- **accumulated savings due to the employment of new tubing material after a time period of five years**
- **accumulated savings due to the employment of new sucker rod string material after a time period of five years**
- **accumulated savings due to the combination of the new technology employments after a time period of five years**

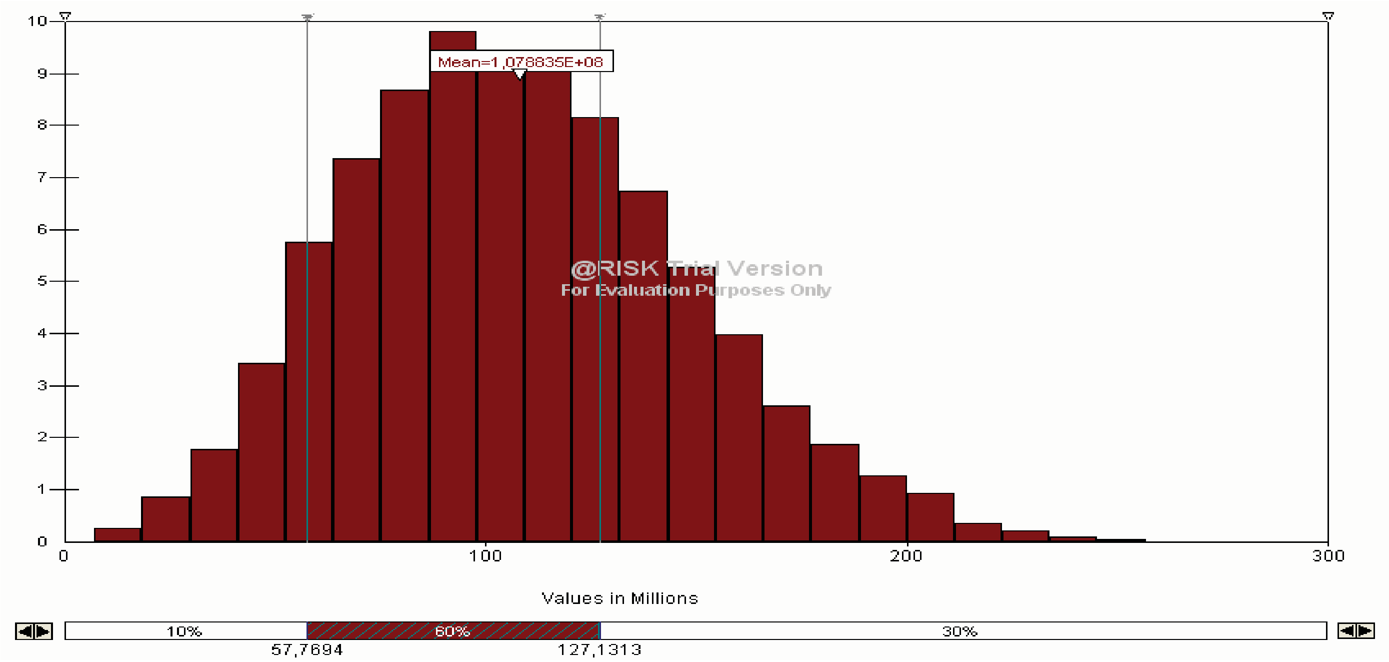
After defining the input and output parameters the Monte Carlo Simulation has been carried out. The procedure of the simulation using the software @risk® has already been explained in detail in section 3.3.2. 10,000 iterations have been carried out during the execution of the simulations.

6.2 Results of the Monte Carlo Simulation

Subsequent to the execution of the Monte Carlo Simulation by means of the software @risk®, the results of the simulations can be displayed on Histograms and Tornado charts. The Histograms show the probability distribution of the defined output. The Tornado charts are used to compare the influences of all input parameters on a certain output parameter after a Monte Carlo Simulation was carried out.

The first histogram, which has been generated by the software @risk® is represented on Fig. 6-1. It shows the probability distribution of the accumulated savings due to the employment of new sucker rod string materials after a time period of five years.

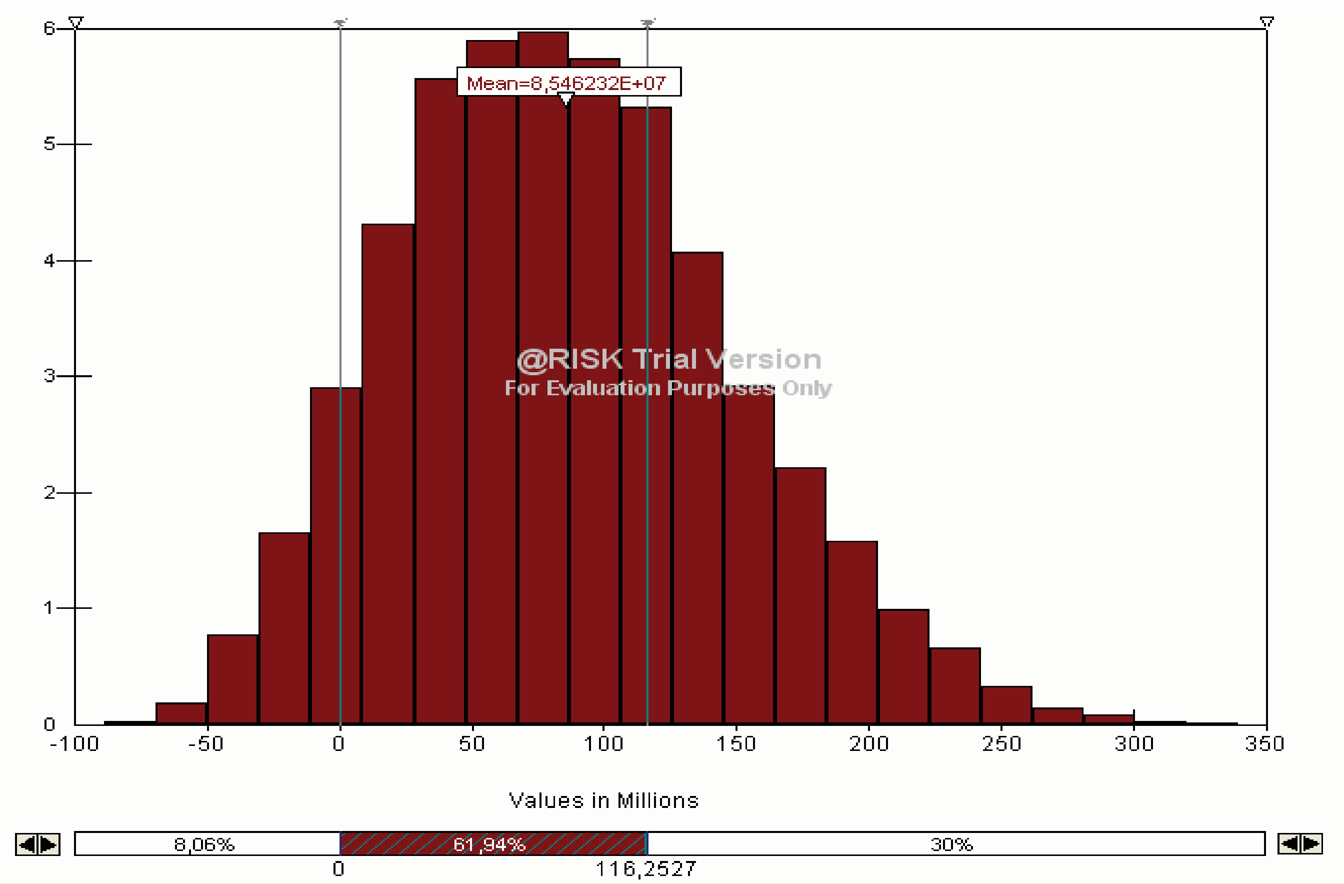
Fig. 6-1 Probability distribution of the total savings due to the employment of new sucker rod string materials after 5 years



As already described in section 3.3.2 certain measured values are used for the interpretation of the histograms. These are the mode, which is the most likely value, the median, which is the mid-value and the mean, which is the weighted average value. The mode of the accumulated savings due to the employment of new sucker rod string materials is 76.770,580.00 Euros, the median is 131.923,675.00 Euros and the mean equals to 107.883,500.00 Euros. The mean value is displayed on Fig. 6-1. Another interesting aspect that can be observed on the histogram is that the probability distribution shows no negative output. That means that even for the lowest assumed oil price, the highest assumed intervention frequencies and the highest presumed material costs, the employment of the corrosion inhibitor will realize cost savings. This fact can be seen on the left side of the histogram. The bar at the lower end of the histogram shows that with a probability of 90% the total savings will be higher than 57.769,400.00 Euros and that with a probability of 30%, the total savings due to the usage of new sucker rod string materials are higher than 127.131,300.00 Euros.

The second histogram shows the probability distribution of the accumulated savings due to the employment of new tubing material after a time period of five years.

Fig. 6-2 Probability distribution of the total savings due to the employment of new tubing materials after 5 years

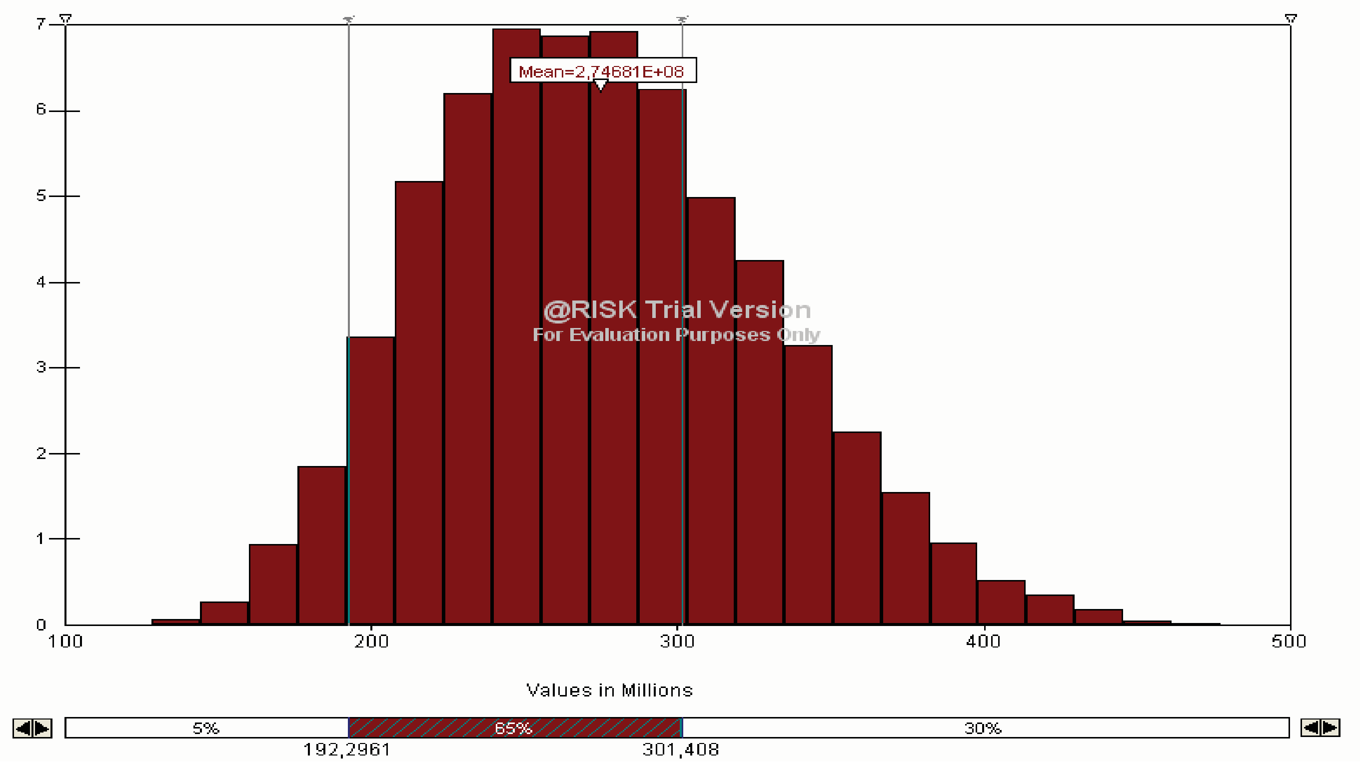


The mode of the accumulated savings due to the employment of new tubing material equals 87.265,960.00 Euros, the median is 125.423,212.00 Euros and the mean is 85.462,320.00 Euros. The mean value is displayed on Fig. 6-2. In contrast to the histogram concerning the employment of new sucker rod string materials, this histogram shows the possibility of a negative output. This negative output would only be realized if, for example, the oil price had the lowest assumed value and the assumed intervention frequencies and the material costs climbed to the highest presumed values. The reason that a negative output could occur in this scenario is the relative high costs for the new tubing material. But the probability of this negative output is just about 8.06%. This fact is also represented on the bar at the lower end of the histogram.

That means that the installation of new tubing materials will realize cost savings with a probability of 91.94%. Fig. 6-3 also shows that with a probability of 30%, the total savings due to the installation of new tubing material are greater than 116.252,700.00 Euros.

The next histogram displays the probability distribution of the accumulated savings due to the employment of corrosion inhibitor after a time period of five years.

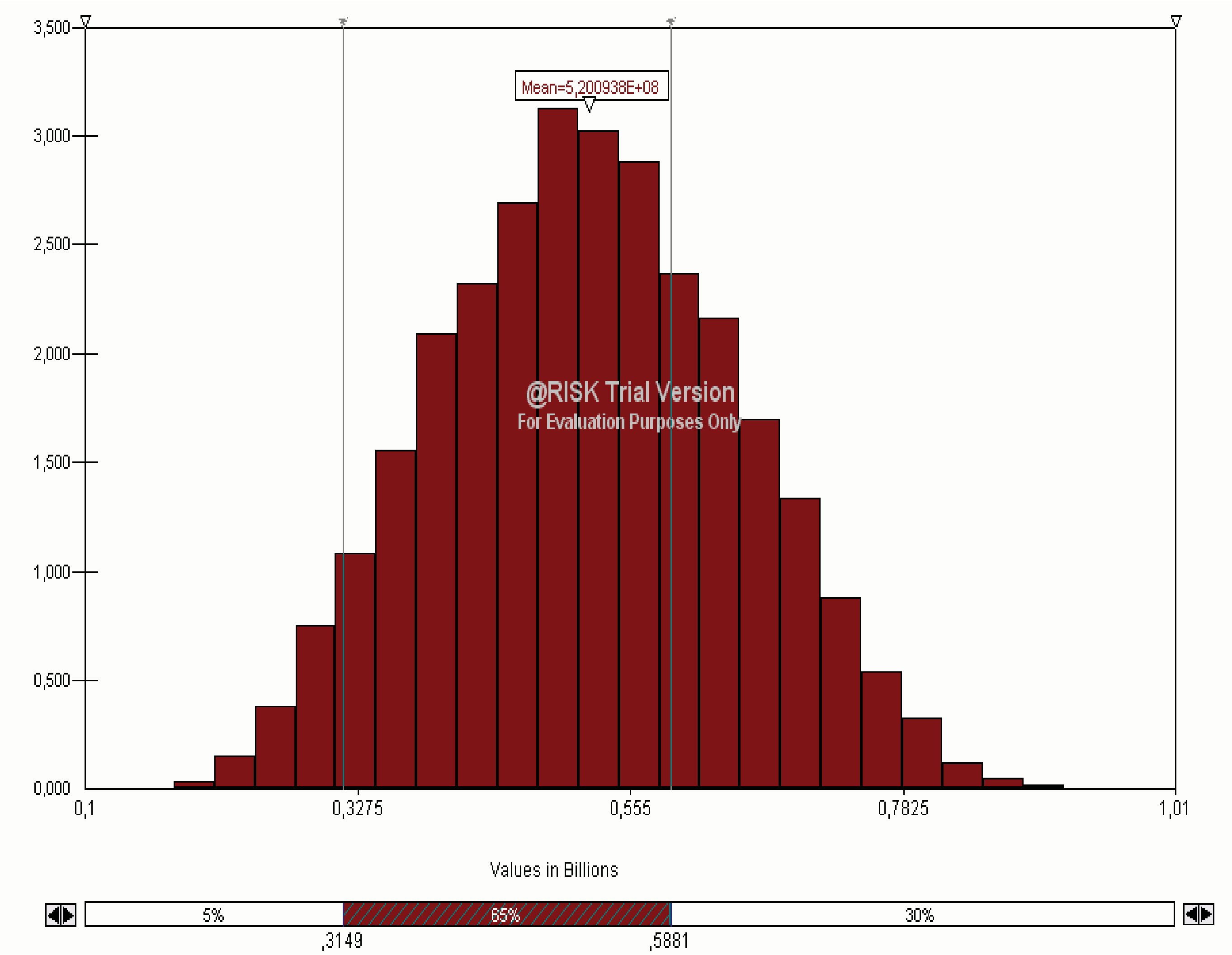
Fig. 6-3 Probability distribution of the total savings due to the employment of corrosion inhibitor after 5 years



The mode of the accumulated savings due to the employment of corrosion inhibitor equals to 244.168,000.00 Euros, the median is 302.979,856.00 Euros and the mean is 274.681,000.00 Euros, which is again displayed on the histogram. As was the case for the employment of new sucker rod string material the probability distribution shows no negative output. That means that the usage of corrosion inhibitor will realize cost savings even for the lowest assumed oil price, the highest assumed intervention frequencies and the highest presumed material costs. The bar at the lower end of the histogram shows that with a probability of 95% the total savings are higher than 192.296,100.00 Euros and that with a probability of 30% the total savings due to the usage of new sucker rod string materials are higher than 301.408,000.00 Euros.

The last histogram displays the probability distribution of the accumulated savings due to the combination of the new technological updates after a time period of five years.

Fig. 6-4 Probability distribution of the total savings due to the combination of the new technology employments after 5 years

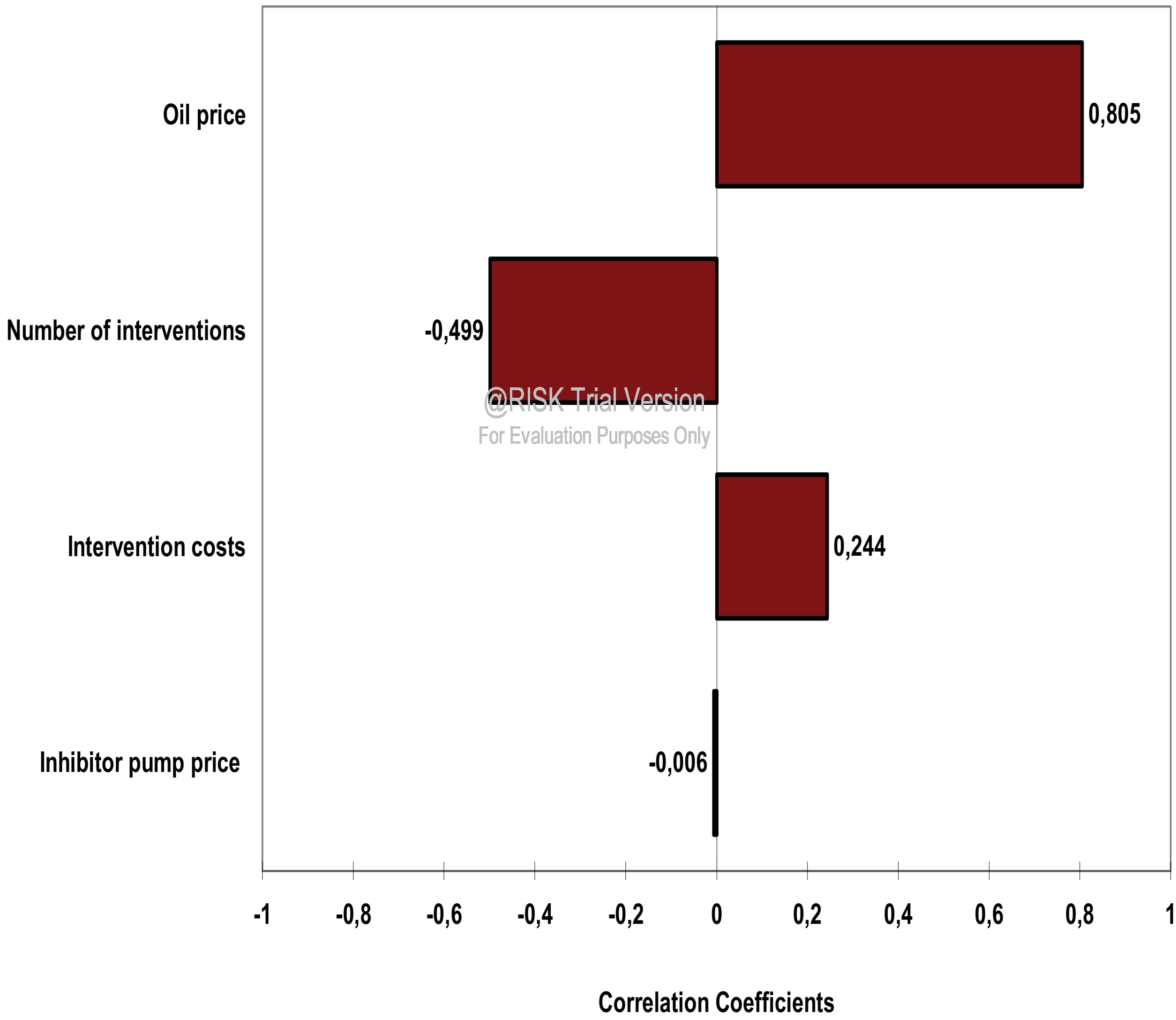


The mode of the accumulated savings due to the combination of the new technology employments is 524.034,600 Euros, the median is 545.081,600.00 Euros and the mean value equals 520.093,800.00 Euros. The mean value can be seen on Fig. 6-4. That means that for the combination of the new technology employments the highest total savings can be expected. As in the case for the employment of corrosion inhibitor and new sucker rod string materials, the probability distribution shows no negative output. That means that the combination of the new technology employments will realize cost savings even for the lowest assumed oil price, the highest assumed intervention frequencies, and the highest presumed material costs. As it can be observed at the lower end of the histogram, with a probability of 95%, the total savings will be higher than 314.900,000.00 Euros and with a probability of 30%, the total savings due to combination of the new technology employments will be higher than 588.100,000.00 Euros.

Tornado charts have been applied for the probabilistic sensitivity analysis of the simulation results. As already explained these tornado charts are used to compare the influences of the input parameters on a certain output parameter. The structure of a Tornado chart has already been described in section 3.3.3.

Fig. 6-5 displays the Tornado chart, which shows influences of the different input parameters on the accumulated savings due to the employment of corrosion inhibitors after a time period of five years.

Fig. 6-5 Influences of the different input parameters on the accumulated savings due to the employment of corrosion inhibitors



The chart shows that the oil price has the highest influence on the total savings which are supposed to be realized due to the usage of corrosion inhibitor. The other two input parameters, which have a relatively high influence on the total savings, are the average intervention costs and the number of intervention per well per year. A very interesting result is that the costs of the inhibitor treatment pumps and the corrosion inhibitor price itself have a very low influence on the total savings. The influence of the corrosion inhibitor price is so low that it is not displayed in the Tornado chart. The reason for this is that the savings due to the reduced number of interventions which are caused by the employment of the corrosion inhibitor are much higher than the costs for the inhibitor treatment pumps and the corrosion inhibitor itself. Therefore, enormous potential savings could be realized by the usage of a corrosion inhibitor.

Fig. 6-6 and Fig. 6-7 show that the number of interventions per well per year and the oil price have the highest influences on the total savings which are supposed to be realized due to the installation of new tubing and sucker rod string material. The other input parameter, which has a relatively high influence on the total savings in both scenarios are the intervention costs. Concerning the employment of new tubing materials the price of the J-55 steel has the fourth highest influence on the total savings, which can be seen on Fig. 6-6. A very interesting result is that the costs of the lining process and the wall thickness survey have a very low influence on the total savings. The reason for this is that the savings due to the reduced number of interventions which are caused by the installation of new material are much higher than the costs for the new materials and the wall thickness survey.

Fig. 6-6 Influences of the different input parameters on the accumulated savings due to the installation of new tubing materials

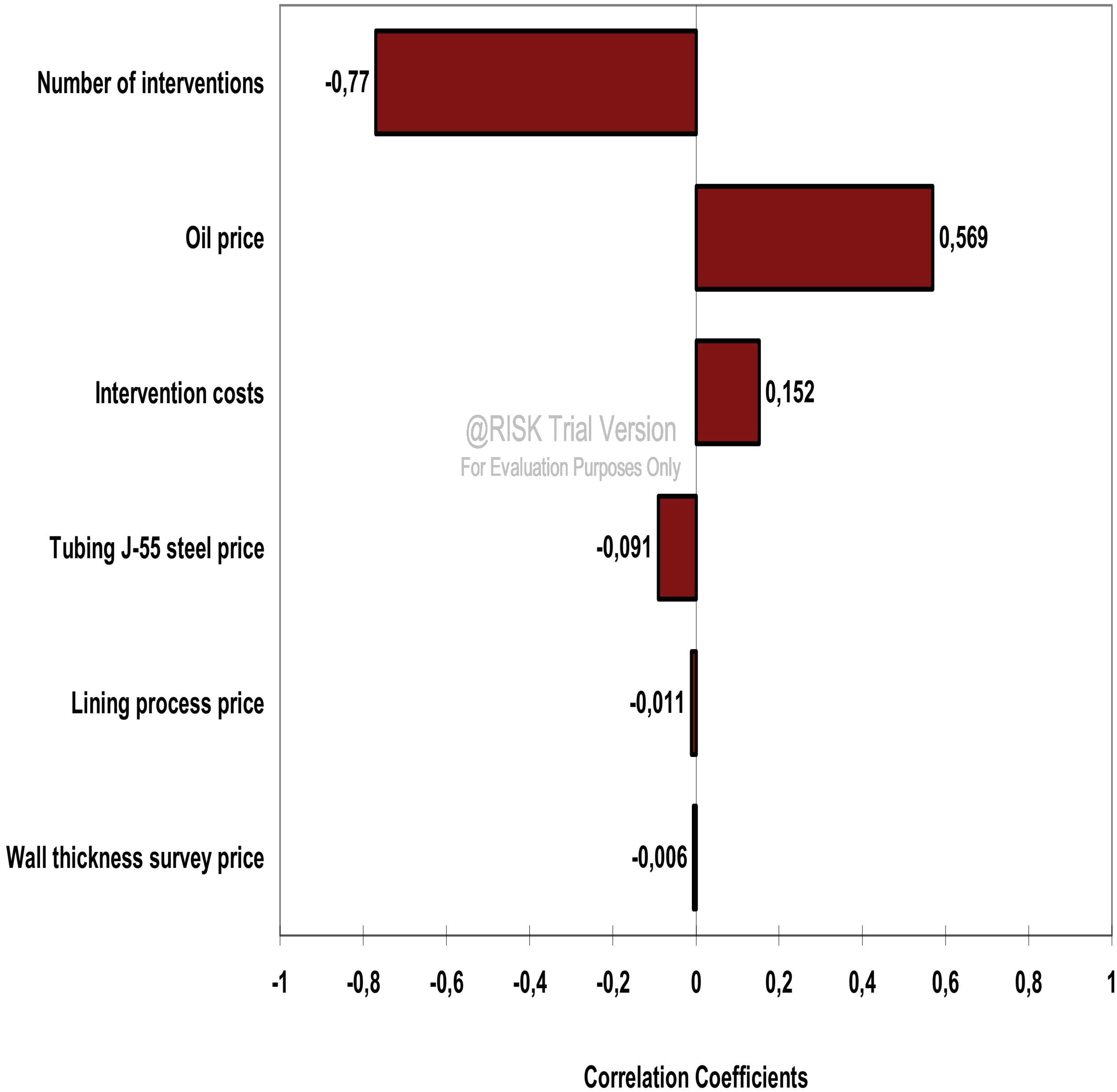


Fig. 6-7 Influences of the different input parameters on the accumulated savings due to the installation of new sucker rod string materials

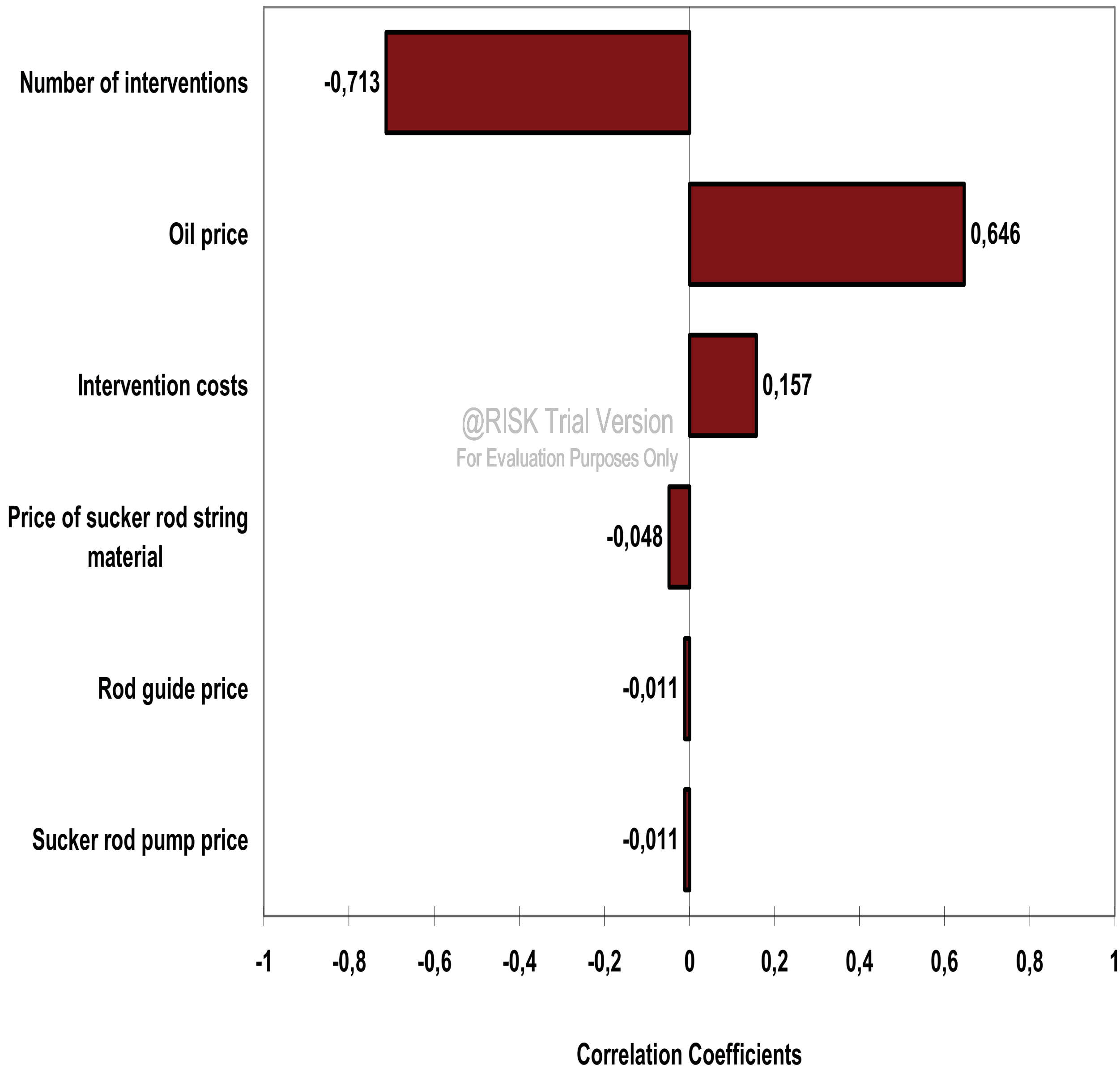
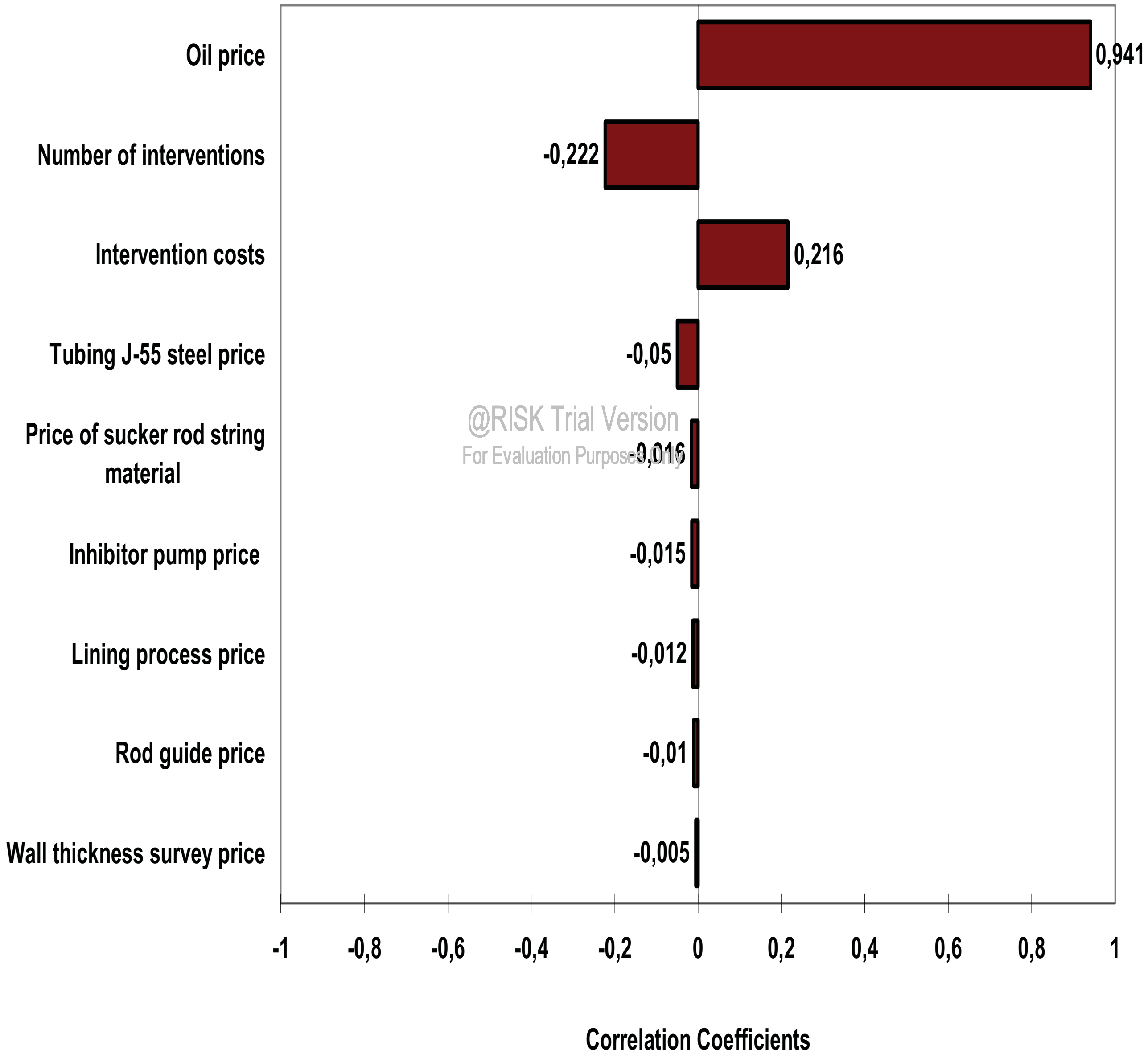


Fig. 6-8 displays the Tornado chart, which shows the influences of the different input parameters on the accumulated savings due to the combination of the new technology employments after a time period of five years.

Fig. 6-8 Influences of the different input parameters on the accumulated savings due to the combination of the new technology employments



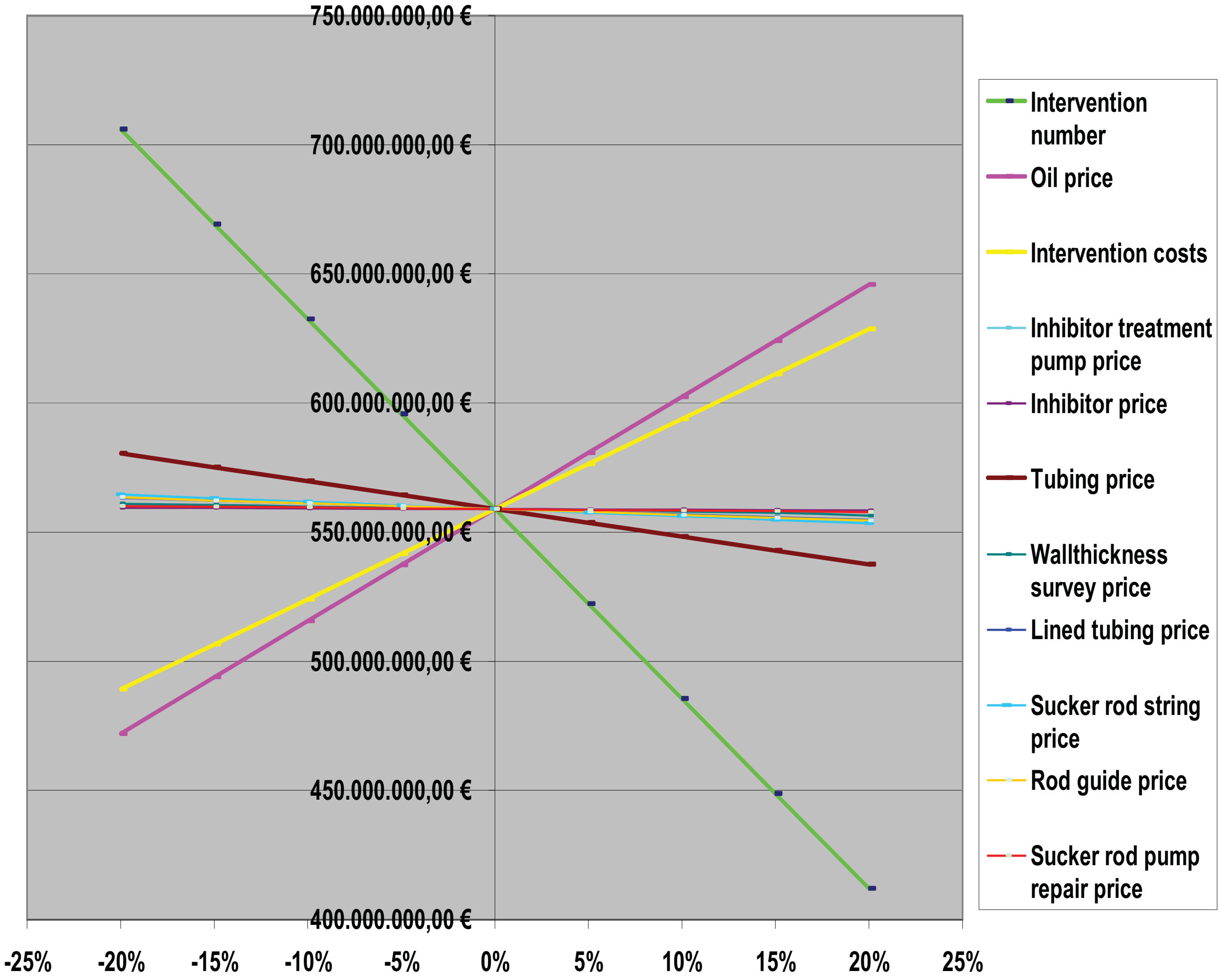
This chart displays that the oil price has the highest influence on the total savings which are caused by the combination of the technology employments. But like in the other scenarios, the intervention costs and the number of interventions per well per year also have a great influence on the total savings. The only material costs which have a definite influence on the savings are the price of the J-55 steel, although its influence is also relatively small compared to the above mentioned factors. The other material costs have a very low influence on the savings, which can also be seen on Fig. 6-8. The reason is again that the savings due to an intervention frequency reduction, which is caused by the new technology employments, are much higher than the costs for these technologies and materials. This fact leads again to enormous potential savings.

6.3 Results of the deterministic sensitivity analysis

The deterministic sensitivity analyses have been carried out by creating a Spider Diagram. This type of diagram shows the influence of a single input parameter on a certain output parameter. For this purpose every single input parameter has been changed in fractional steps to show how strong the influence of the parameter is. After that the change of the output parameter with each of the input parameters is plotted. By constructing a plot for every single input parameter in one diagram a spider diagram is created. The steeper a graph in a spider diagram is, the higher is its influence on the output parameter. This procedure has also been described in section 3.3.3.

Fig. 6-9 displays the influence of the defined input parameters on the total savings which are caused by the combination of the technology employments.

Fig. 6-9 Influence of the defined input parameters on the total savings



The input parameters have been changed in five percent steps from -20% to +20%. The Spider Diagram displays that just the number of interventions, the oil price and the intervention costs have a significant influence on the total savings.

As can be observed on the diagram, the total savings are increasing more and more, if the number of interventions per well is decreased. Or, in other words, if the new technology employments would not lead to the assumed intervention reduction, the total savings would be lower. This fact is further discussed later on.

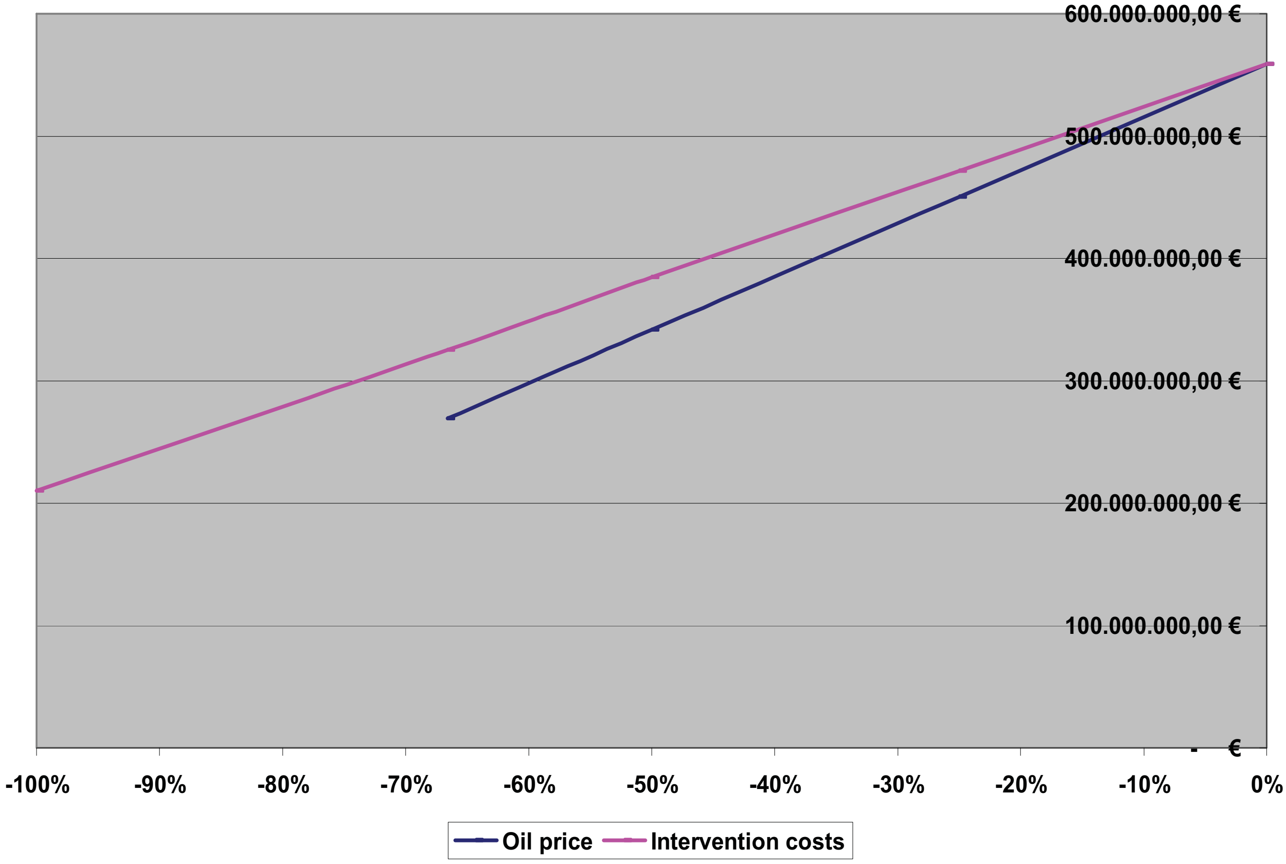
Another interesting point that can be seen on the diagram is that the total savings increase, if the average costs for an intervention are increased. That means that the higher the price for an intervention is the more money can be saved by preventing this intervention with the employment of new technologies. Or, in other words, the lower the price for an intervention is the less money can be saved by reducing the intervention frequency.

Fig. 6-9 also displays that the total savings are decreasing with increasing material costs. But with the exception of the J-55 tubing steel price, the material costs have a negligible influence on the total savings.

As already described in preceding chapters, the reduction of the intervention frequency leads to savings due to the reduced intervention costs. Furthermore the intervention frequency decrease leads to a production increase. Consequently more produced oil can be sold, which are additional revenues and accordingly savings. The total savings would never fall below zero, even if the intervention costs would receive the unrealistic value of 0, because the savings due to the production increase will always be higher than the costs for the new technologies. This fact is represented on Fig. 6-10. But this is just a theoretical assumption which could never occur in reality. It should just show that savings due to the production increase are much higher than the costs for the introduction of the combination of new technologies.

Fig. 6-9 also displays that the total savings decrease as the oil price decreases. Fig. 6-10shows the development of the total savings for a further reduction of the oil price. In this case the oil price has been decreased to - 66.66% of its initial value of $60, which equals $20. But even in this case the total savings would not be zero, because the savings due to the reduction of the intervention costs and the savings due to the production increase would be higher than the costs for the new technologies.

Fig. 6-10 Influence of the oil price and the intervention costs

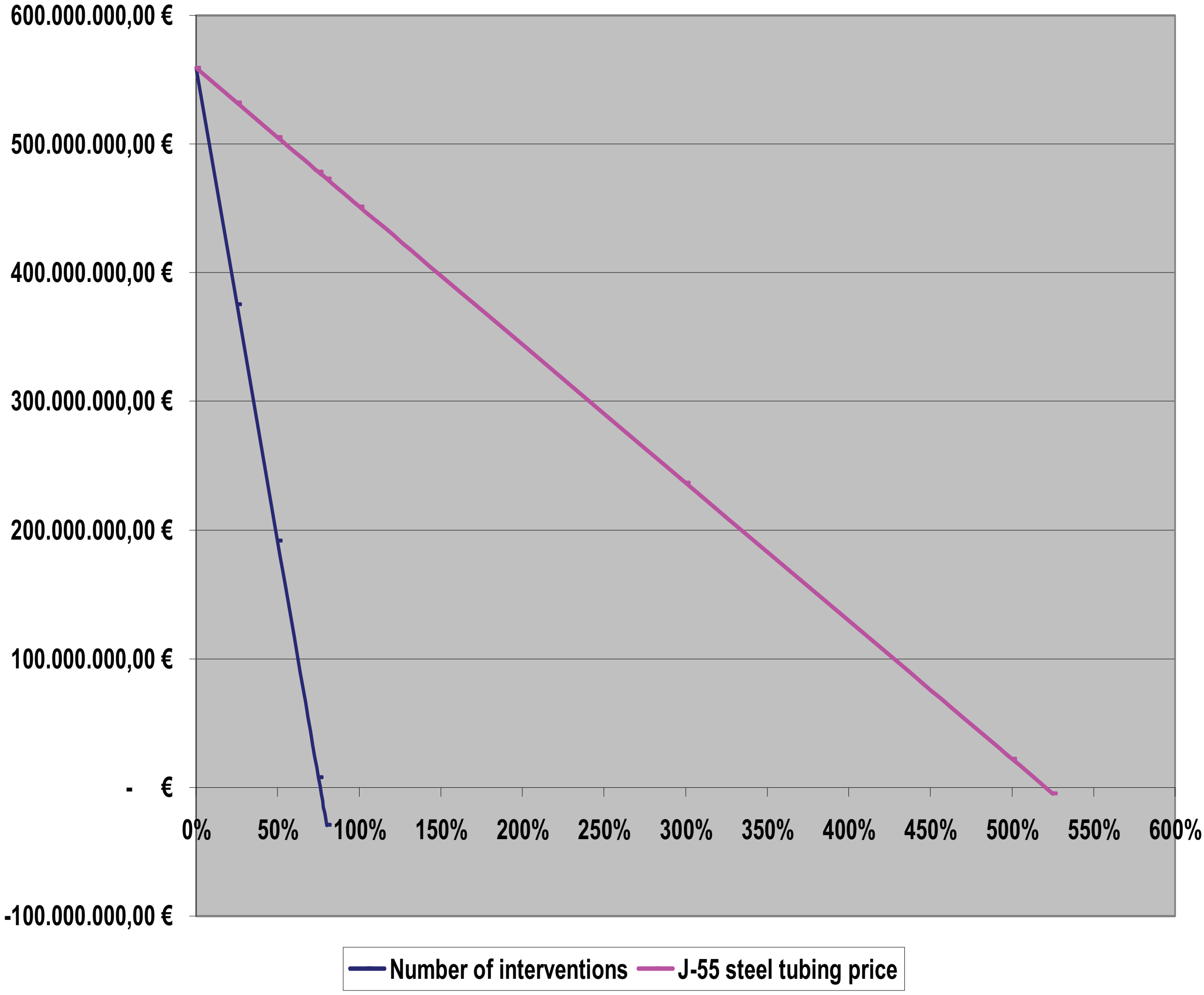


For the combination of the technology employments the intervention frequency for all the 7,579 sucker rod pumped wells has been assumed at:

- **eight interventions per well per year in the first year of installation**
- **five and a half interventions per well per year in the second year of installation**
- **three interventions per well per year in the third year of installation**
- **two and a half interventions per well per year in the fourth year of installation**
- **two interventions per well per year in the fifth year of installation**

These figures have also been represented on Tab. 5-58. The sum of these interventions is 21. That means that on average every well would have 21 interventions in the five years of the calculation model. For these assumed 21 interventions for the first five years the total savings would be about 560 million Euros, which has been shown in preceding chapters. As explained before, an increasing number of interventions would lead to lower total savings. For this reason the number of interventions has been further increased to find out the limit at which no savings are realized any more. This limit is approximately 37 interventions per well per year for the five years of the calculation model. This value of 37 interventions per well per year is about 76% higher than the assumed 21 interventions per well per year. The graph of this calculation is represented on Fig. 6-11. That means that if on average every well has less than 37 interventions in the first five years of the new technology employments, these new technologies would lead to cost savings.

Fig. 6-11 Influence of the number of interventions and J-55 steel tubing price



The J-55 steel tubing price has also been further increased to detect the value at which no savings are realized any more. Fig. 6-11 also displays this price limit, which is about 115 Euro per meter. This value is approximately 525% higher than the presumed J-55 steel tubing price of 18.5 Euro per meter. Concerning the deterministic analysis, no interaction between the input parameters can be considered. Therefore, if several unfavorable situations develop, the limit at which no savings are realized anymore could occur earlier.

7 Conclusion

The results show that the assumed intervention frequency decrease due to the employment of new technologies leads to a significant production increase and enormous potential savings.

Due to the outputs of the calculation model, it can be demonstrated that the employment of the corrosion inhibitor realizes the highest savings in comparison to the installation of new tubing or sucker rod string material. This fact is displayed on Fig. 5-12. The estimated savings caused by the employment of the corrosion inhibitor in the most realistic case are about 300 million Euros five years after the first installation. The estimated savings due to the installation of new tubing or sucker rod string material in the most realistic cases are approximately 100 million Euros five years after the first installation. That means that the savings due to the corrosion inhibitor are almost three times higher than savings due to the installation of new material. The reason for this is, that in the assumed most realistic case of the corrosion inhibitor employment, all the corrosion inhibitor treatment pumps are installed by the third year of the calculation model. After the third year, only the costs of the corrosion inhibitor itself and the costs of the maintenance of the pumps remain, which are significantly lower than the costs of the pumps. This outstanding decrease of the corrosion inhibitor costs is displayed on Fig. 5-11.

But the highest savings due to the reduction of the intervention frequency are projected to be realized with the combination of the employment of the new technologies. These savings achieve a value of about 550 million Euros five years after the first installation. The results of the Monte Carlo Simulation, which takes the variability of the input parameters into consideration, shows that these potential savings could even go up to about 800 million Euros.

The results of the probabilistic and the deterministic sensitivity analyses show that just three input parameters have a significantly high influence on the total savings. These are the oil price, the number of interventions and the intervention costs. The costs of the materials have a very low influence on the total savings. The reason for this is that the savings due to the reduced number of interventions which are caused by the employment of the new technologies are much higher than the costs for the new technologies. This fact can also be seen on Fig. 5-11. This is another proof that huge potential savings could be realized by the employment of the new technologies.

Another important point is that by employing new technologies and new materials at low producing wells, the production of these wells can be increased. Therefore these wells do not have to be shut down, which also realizes enormous cost savings.

7.1 Recommendations

1. Installation of at least 5000 inhibitor treatment skids at sucker rod pumped wells in Romania in the following years.
2. Additionally equip about 10% of the sucker rod pumped wells per year with new tubing and sucker rod string material.
3. Additionally introduce the wall thickness survey measurement to find out the tubings which can still be used in other wells.

Therefore, the output and recommendation due to the result of this thesis is to employ corrosion inhibitors and new materials in Romania instantaneously. This employment will reduce the intervention frequency, increase the annual production time, prevent shutting down low producing wells and consequently lead to huge savings.

7.2 Outlook

It would be advisable to check the annual intervention frequencies in the years after the employment of the new technologies and to compare these with the intervention frequencies, which have been assumed in the thesis. If the real annual number of interventions coincides with the assumed annual number of interventions, these assumptions could be also applied for future estimations concerning the employment of the new technologies.

8 Summary

This thesis intends to estimate the total savings and the production increase, which are caused by the employment of new technologies at the 7,579 sucker rod pumped wells in Romania. These technologies include the installation of new tubing material, which is additionally equipped with thermoplastic tubular liners, the installation of new sucker rod strings and the employment of corrosion inhibitors.

For every new technology an employment scenario – including a best, worst and most realistic case – has been calculated. Furthermore an employment scenario for the combination of the most realistic cases has been evaluated.

In the first two chapters of the thesis the economical methods, which have been used for the calculations and the technical background of the new technologies are explained in detail.

The next part of the thesis is the description of the calculation model, which has been created in Microsoft Excel® to estimate the production increase and the total savings due to the usage of the new technologies. The new technologies are supposed to decrease the actual average intervention frequency of 10 interventions per well per year. This intervention frequency decrease leads to a higher production time and hence more production. For this purpose a certain intervention frequency decrease for every planned employment scenario has been assumed. For the evaluation of the total savings the net present value method has been used. The savings have been computed by calculating the difference of the net present value assuming 10 interventions per year and the net present value assuming a reduced number of interventions per year.

The results of the calculation model show that particularly the employment of corrosion inhibitors and the combination of the new technologies realize huge savings due to the reduced number of interventions.

After the construction of the calculation model, a Monte Carlo Simulation was carried out. For the execution of the simulations the software @risk® was used. The simulations have been created so as to consider the variability of the different input parameters of the calculation model and to compare their influences on the total savings. The defined input parameters are the oil price, the number of interventions, the intervention costs and the costs of the different materials. The results of the simulations are shown on Histograms and Tornado Charts. In additional to the probabilistic sensitivity analyses of the Monte Carlo Simulation, deterministic sensitivity analyses have been carried out to show the influence of a single input parameter on the total savings. The results of these analyses are displayed in a Spider Diagram.

The Tornado charts and the Spider Diagram show that just the oil price, the number of interventions and the intervention costs have a significant influence on the total savings. In comparison to these, the influences of the material costs on the total costs are very low. The reason for this is that the savings due to the reduced number of interventions which are caused by the employment of the new technologies are significantly higher than the costs for the new technologies. This fact also emphasizes that enormous potential savings could be realized by the employment of the new technologies.

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10 Appendix

Tab. 10-1 Annual production increases, annual revenues and annual intervention cost savings of the 500 wells equipped with inhibitor treatment pumps in the third year in the worst case

Inhibitor (Worst case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	500	wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	17.033,78 €	11.355,85 €	11.355,85 €
Total intervention costs/year (new) [Euro/year]:		11.355.850,00 €	11.355.850,00 €	8.516.887,50 €	5.677.925,00 €	5.677.925,00 €
Total intervention costs/year (old) [Euro/year]:		11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	11.355.850,00 €
Production losses/well/year [tons/year]:		108,92	98,03	66,17	39,70	35,73
Total production losses/year [tons/year]:		54.460,86	49.014,78	33.084,97	19.850,90	17.865,89
Total production losses/year [bbl/year]:		399.198,11	359.278,30	242.512,05	145.507,71	130.956,94
Total oil production/year (old) [tons/year]:		218.441,92	196.597,72	176.937,95	159.244,16	143.319,74
Total oil production/year (old) [bbl/year]:		1.601.179,25	1.441.061,32	1.296.955,19	1.167.259,67	1.050.533,70
Production increase/year [bbl/year]:		0,00	0,00	80.837,62	145.507,71	130.956,94
Total oil production/year (new) [bbl/year]:		1.601.179,25	1.441.061,32	1.377.792,81	1.312.767,38	1.181.490,64
Revenues / year [Euro/year]:		72.053.066,04 €	64.847.759,43 €	62.000.676,30 €	59.074.532,19 €	53.167.078,87 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	2.838.962,50 €	5.677.925,00 €	5.677.925,00 €

Tab. 10-2 Annual production increase, annual revenues and annual intervention cost savings of the 500 wells equipped with inhibitor treatment pumps in the fourth year in the worst case

Inhibitor (Worst case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	500	wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	17.033,78 €	11.355,85 €
Total intervention costs/year (new) [Euro/year]:		11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	8.516.887,50 €	5.677.925,00 €
Total intervention costs/year (old) [Euro/year]:		11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	11.355.850,00 €
Production losses/well/year [tons/year]:		108,9217226	98,02955031	88,22659528	59,55295181	35,73177109
Total production losses/year [tons/year]:		54.460,86	49.014,78	44.113,30	29.776,48	17.865,89
Total production losses/year [bbl/year]:		399.198,11	359.278,30	323.350,47	218.261,57	130.956,94
Total oil production/year (old) [tons/year]:		218.441,92	196.597,72	176.937,95	159.244,16	143.319,74
Total oil production/year (old) [bbl/year]:		1.601.179,25	1.441.061,32	1.296.955,19	1.167.259,67	1.050.533,70
Production increase/year [bbl/year]:		0,00	0,00	0,00	72.753,86	130.956,94
Total oil production/year (new) [bbl/year]:		1.601.179,25	1.441.061,32	1.296.955,19	1.240.013,53	1.181.490,64
Revenues / year [Euro/year]:		72.053.066,04 €	64.847.759,43 €	58.362.983,49 €	55.800.608,67 €	53.167.078,87 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	2.838.962,50 €	5.677.925,00 €

Tab. 10-3 Annual production increase, annual revenues and annual intervention cost savings of the 500 wells equipped with inhibitor treatment pumps in the fifth year in the worst case

Inhibitor (Worst case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	500	wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	17.033,78 €
Total intervention costs/year (new) [Euro/year]:		11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	8.516.887,50 €
Total intervention costs/year (old) [Euro/year]:		11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	11.355.850,00 €	11.355.850,00 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	79,40	53,60
Total production losses/year [tons/year]:		54.460,86	49.014,78	44.113,30	39.701,97	26.798,83
Total production losses/year [bbl/year]:		399.198,11	359.278,30	323.350,47	291.015,42	196.435,41
Total oil production/year (old) [tons/year]:		218.441,92	196.597,72	176.937,95	159.244,16	143.319,74
Total oil production/year (old) [bbl/year]:		1.601.179,25	1.441.061,32	1.296.955,19	1.167.259,67	1.050.533,70
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	65.478,47
Total oil production/year (new) [bbl/year]:		1.601.179,25	1.441.061,32	1.296.955,19	1.167.259,67	1.116.012,17
Revenues / year [Euro/year]:		72.053.066,04 €	64.847.759,43 €	58.362.983,49 €	52.526.085,14 €	50.220.547,80 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	2.838.962,50 €

Tab. 10-4 Annual production increase, annual revenues and annual intervention cost savings of the wells which are not equipped with inhibitor treatment pumps in the worst case

Inhibitor (Worst case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	5.079	wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €
Total intervention costs/year (new) [Euro/year]:		115.352.724,30 €	115.352.724,30 €	115.352.724,30 €	115.352.724,30 €	115.352.724,30 €
Total intervention costs/year (old) [Euro/year]:		115.352.724,30 €	115.352.724,30 €	115.352.724,30 €	115.352.724,30 €	115.352.724,30 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	79,40	71,46
Total production losses/year [tons/year]:		553.213,43	497.892,09	448.102,88	403.292,59	362.963,33
Total production losses/year [bbl/year]:		4.055.054,43	3.649.548,99	3.284.594,09	2.956.134,68	2.660.521,21
Total oil production/year (old) [tons/year]:		2.218.932,88	1.997.039,69	1.797.335,72	1.617.602,15	1.455.841,93
Total oil production/year (old) [bbl/year]:		16.264.778,77	14.638.300,90	13.174.470,81	11.857.023,73	10.671.321,35
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	0,00
Total oil production/year (new) [bbl/year]:		16.264.778,77	14.638.300,90	13.174.470,81	11.857.023,73	10.671.321,35
Revenues / year [Euro/year]:		731.915.044,81 €	658.723.540,33 €	592.851.186,30 €	533.566.067,67 €	480.209.460,90 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	- €

Tab. 10-5 Annual production increase, annual revenues and annual intervention cost savings of the 2,000 wells equipped with inhibitor pumps in the third year in the most realistic case

Inhibitor (Most realisitic case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	2.000	wells				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	17.033,78 €	11.355,85 €	11.355,85 €
Total intervention costs/year (new) [Euro/year]:		45.423.400,00 €	45.423.400,00 €	34.067.550,00 €	22.711.700,00 €	22.711.700,00 €
Total intervention costs/year (old) [Euro/year]:		45.423.400,00 €	45.423.400,00 €	45.423.400,00 €	45.423.400,00 €	45.423.400,00 €
Production losses/well/year [tons/year]:		108,92	98,03	66,17	39,70	35,73
Total production losses/year [tons/year]:		217.843,45	196.059,10	132.339,89	79.403,94	71.463,54
Total production losses/year [bbl/year]:		1.596.792,45	1.437.113,21	970.051,42	582.030,85	523.827,76
Total oil production/year (old) [tons/year]:		873.767,88	786.390,90	707.751,81	636.976,63	573.278,96
Total oil production/year (old) [bbl/year]:		6.404.716,98	5.764.245,28	5.187.820,75	4.669.038,68	4.202.134,81
Production increase/year [bbl/year]:		0,00	0,00	323.350,47	582.030,85	523.827,76
Total oil production/year (new) [bbl/year]:		6.404.716,98	5.764.245,28	5.511.171,23	5.251.069,53	4.725.962,58
Revenues / year [Euro/year]:		288.212.264,15 €	259.391.037,74 €	248.002.705,19 €	236.298.128,77 €	212.668.315,90 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	11.355.850,00 €	22.711.700,00 €	22.711.700,00 €

Tab. 10-6 Annual production increase, annual revenues and annual intervention cost savings of the wells which are not equipped with inhibitor treatment pumps in the most realistic case

Inhibitor (Most realisitic case)	Number of wells	1st year	2nd year	3rd year	4th year	5th year
For	2.579	wells				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €
Total intervention costs/year (new) [Euro/year]:		58.573.474,30 €	58.573.474,30 €	58.573.474,30 €	58.573.474,30 €	58.573.474,30 €
Total intervention costs/year (old) [Euro/year]:		58.573.474,30 €	58.573.474,30 €	58.573.474,30 €	58.573.474,30 €	58.573.474,30 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	79,40	71,46
Total production losses/year [tons/year]:		280909,12	252818,21	227536,39	204782,75	184304,48
Total production losses/year [bbl/year]:		2059063,87	1853157,48	1667841,73	1501057,56	1350951,80
Total oil production/year (old) [tons/year]:		1126723,40	1014051,06	912645,96	821381,36	739243,22
Total oil production/year (old) [bbl/year]:		8258882,55	7432994,29	6689694,86	6020725,38	5418652,84
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	0,00
Total oil production/year (new) [bbl/year]:		8258882,55	7432994,29	6689694,86	6020725,38	5418652,84
Revenues / year [Euro/year]:		371.649.714,62 €	334.484.743,16 €	301.036.268,84 €	270.932.641,96 €	243.839.377,76 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	- €

Fig. 10-1 Total oil production [bbl] for different corrosion inhibitor scenarios

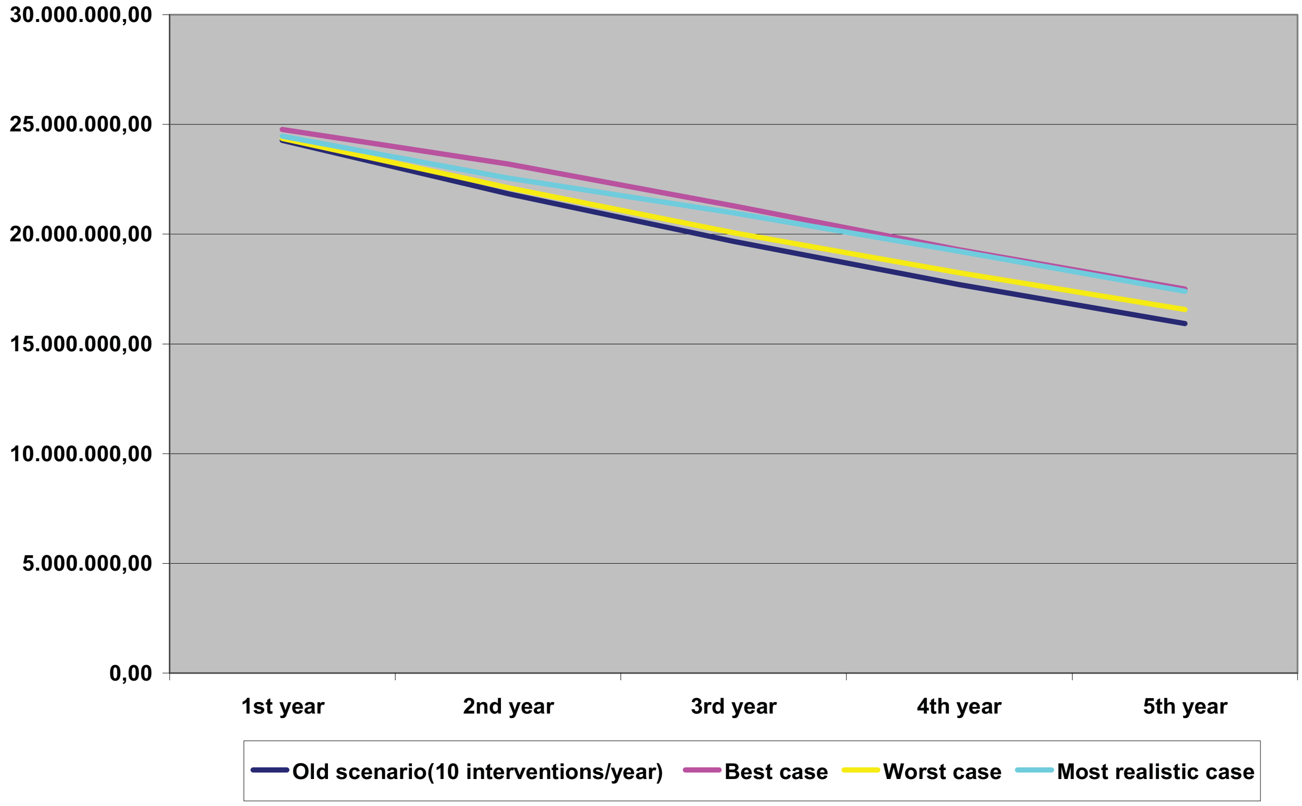


Fig. 10-2 Annual production increase [bbl] for different corrosion inhibitor scenarios

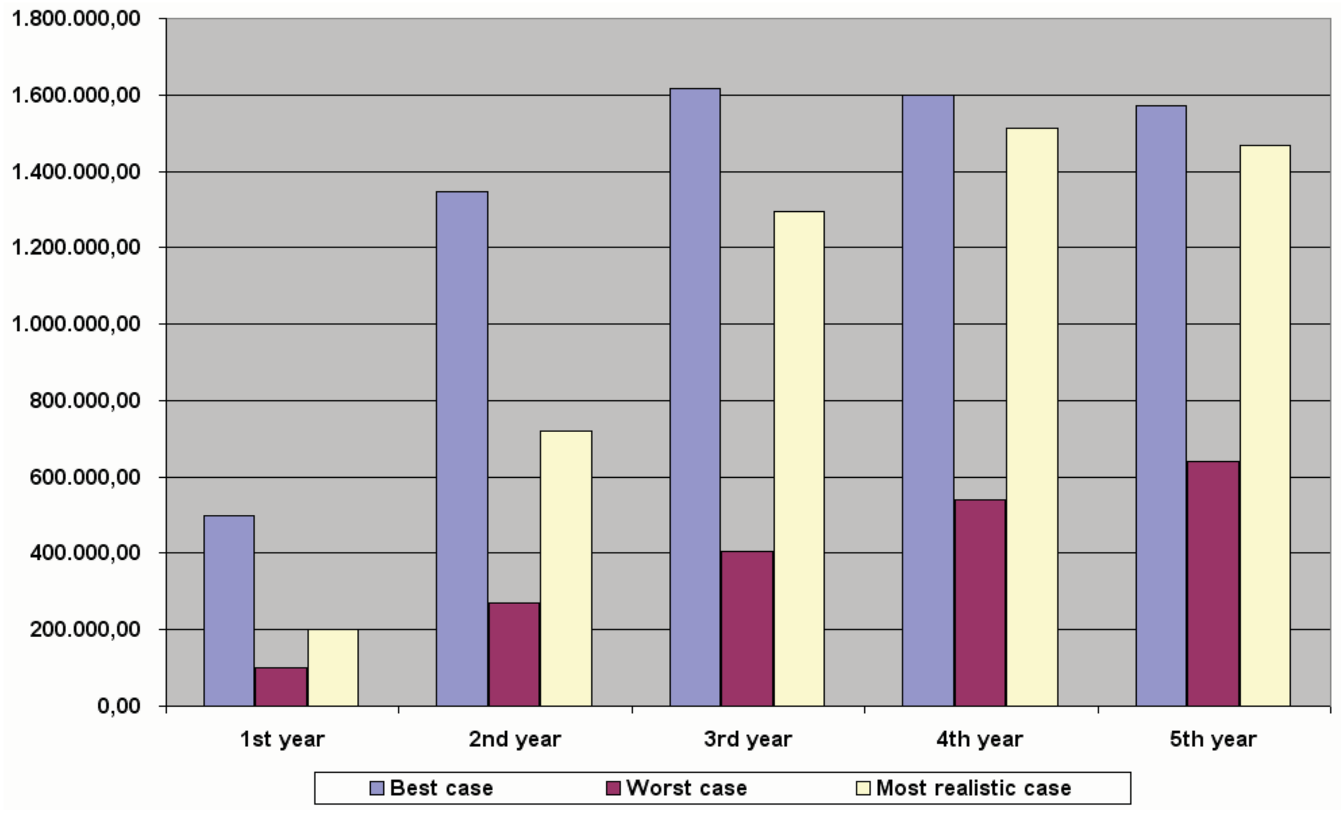
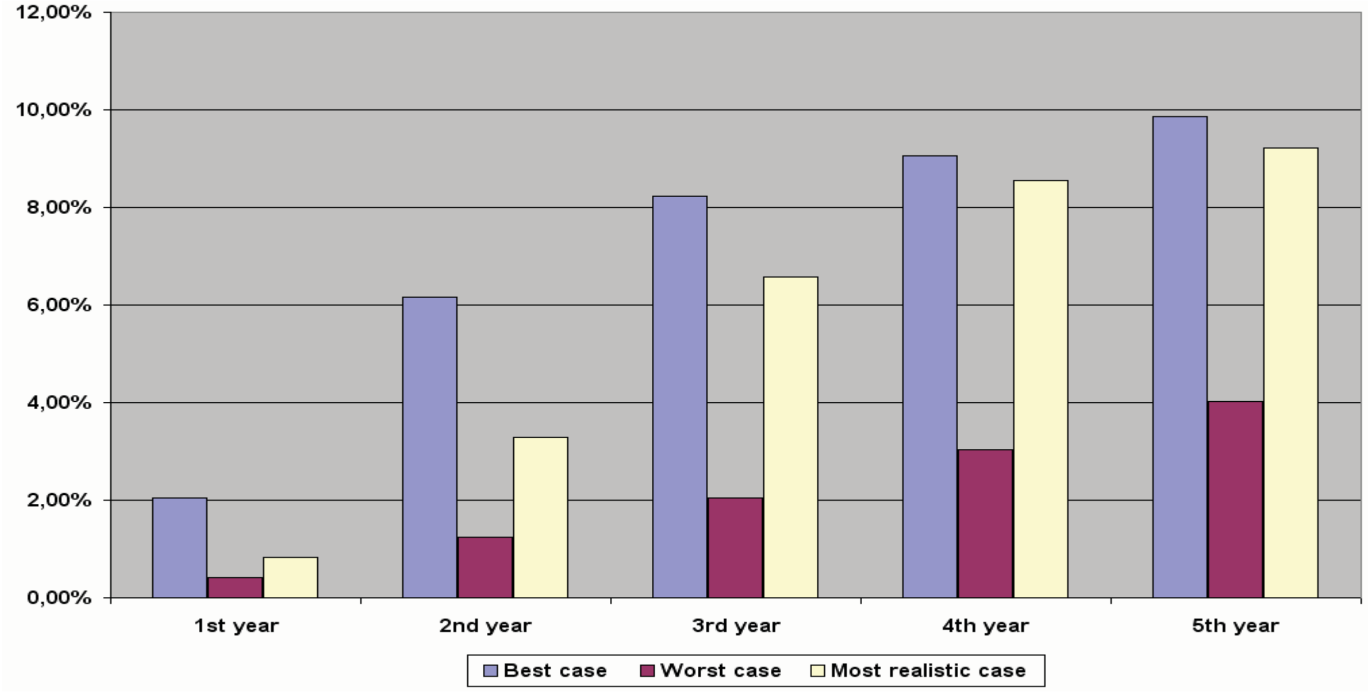


Fig. 10-3 Annual production increase in percent for different corrosion inhibitor scenarios



Tab. 10-7 Difference in the net present value for the worst case

Inhibitor (Worst case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Annual revenues due to the oil production [Euro/year]:	1.213.533.750,00 €	1.096.871.353,77 €	995.087.980,19 €	902.854.567,78 €	820.426.527,47 €	745.455.549,54 €
Annual savings due to reduced interventions [Euro/year]:		2.838.962,50 €	5.677.925,00 €	8.516.887,50 €	15.330.397,50 €	21.008.322,50 €
Annual capex [Euro/year]:	2.500.000,00 €	2.500.000,00 €	2.500.000,00 €	2.500.000,00 €	2.500.000,00 €	2.500.000,00 €
Annual opex [Euro/year]:		451.891,07 €	944.277,40 €	938.953,69 €	995.759,46 €	1.022.871,31 €
Annual cash flow(Worst case)[Euro/year]:	1.211.033.750,00 €	1.096.558.425,20 €	997.421.627,79 €	907.932.501,59 €	832.261.165,51 €	762.941.000,73 €
Discounted cash flow(10 interventions per year)[Euro/year]:	1.213.533.750,00 €	983.946.283,78 €	797.794.284,15 €	646.860.230,39 €	524.481.267,88 €	425.255.082,07 €
Discounted cash flow(Worst case)[Euro/year]:		987.890.473,16 €	809.529.768,51 €	663.872.419,07 €	548.236.208,30 €	452.768.350,11 €
Net present value (10 interventions per year)[Euro/year]:		2.197.480.033,78 €	2.995.274.317,93 €	3.642.134.548,32 €	4.166.615.816,21 €	4.591.870.898,28 €
Net present value (Worst case)[Euro/year]:		2.198.924.223,16 €	3.008.453.991,67 €	3.672.326.411,64 €	4.220.562.619,94 €	4.673.330.970,05 €
Difference in net present value [Euro/year]:	- 2.500.000,00 €	1.444.189,37 €	13.179.673,74 €	30.191.863,31 €	53.946.803,73 €	81.460.071,77 €

Tab. 10-8 Difference in the net present value for the most realistic case

Inhibitor (Most realisitic case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Annual revenues due to the oil production [Euro/year]:	1.213.533.750,00 €	1.101.162.332,55 €	1.015.297.384,67 €	942.869.188,66 €	884.797.102,71 €	782.581.842,32 €
Annual savings due to reduced interventions [Euro/year]:		14.194.812,50 €	42.584.437,50 €	56.779.250,00 €	62.457.175,00 €	68.135.100,00 €
Annual capex [Euro/year]:	5.000.000,00 €	10.000.000,00 €	10.000.000,00 €	- €	- €	- €
Annual opex [Euro/year]:		882.530,45 €	2.303.313,94 €	2.360.693,51 €	2.274.624,16 €	2.197.181,74 €
Annual cash flow(Most realistic case)[Euro/year]:	1.208.533.750,00 €	1.104.474.614,60 €	1.045.578.508,23 €	997.287.745,15 €	924.479.653,56 €	848.519.760,58 €
Discounted cash flow(10 interventions per year)[Euro/year]:	1.213.533.750,00 €	983.946.283,78 €	797.794.284,15 €	646.860.230,39 €	524.481.267,88 €	425.255.082,07 €
Discounted cash flow(Most realistic case)[Euro/year]:		995.022.175,31 €	848.614.973,00 €	729.208.202,83 €	608.983.382,78 €	503.555.190,87 €
Net present value (10 interventions per year)[Euro/year]:		2.197.480.033,78 €	2.995.274.317,93 €	3.642.134.548,32 €	4.166.615.816,21 €	4.591.870.898,28 €
Net present value (Most realistic case)[Euro/year]:		2.203.555.925,31 €	3.052.170.898,31 €	3.781.379.102,24 €	4.390.362.485,00 €	4.893.917.675,87 €
Difference in net present value [Euro/year]:	- 5.000.000,00 €	6.075.891,53 €	56.896.580,38 €	139.244.553,92 €	223.746.668,80 €	302.046.777,40 €

Tab. 10-9 Annual production increase, annual revenues and annual intervention cost savings of the 15% of the wells equipped with new tubing material in the third year in the best case

Tubing string (Best case)	Percentage of wells	1styear	2ndyear	3rdyear	4thyear	5thyear
For	15,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	13.627,02 €	6.813,51 €	6.813,51 €
Total intervention costs/year (new) [Euro/year]:		25.819.798,15 €	25.819.798,15 €	15.491.877,89 €	7.745.938,84 €	7.745.938,84 €
Total intervention costs/year (old) [Euro/year]:		25.819.798,15 €	25.819.798,15 €	25.819.798,15 €	25.819.798,15 €	25.819.798,15 €
Production losses/well/year [tons/year]:		108,92	98,03	52,94	23,82	21,44
Total production losses/year [tons/year]:		123.827,66	111.444,89	60.180,24	27.081,11	24.373,00
Total production losses/year [bbl/year]:		907.656,75	816.891,08	441.121,18	198.504,53	178.654,08
Total oil production/year (old) [tons/year]:		496.671,38	447.004,25	402.303,82	362.073,44	325.866,10
Total oil production/year (old) [bbl/year]:		3.640.601,25	3.276.541,13	2.948.887,01	2.653.998,31	2.388.598,48
Production increase/year [bbl/year]:		0,00	0,00	294.080,79	463.177,24	416.859,52
Total oil production/year (new) [bbl/year]:		3.640.601,25	3.276.541,13	3.242.967,80	3.117.175,55	2.805.458,00
Revenues / year [Euro/year]:		163.827.056,25 €	147.444.350,63 €	145.933.550,98 €	140.272.899,79 €	126.245.609,81 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	10.327.918,46 €	18.073.857,30 €	18.073.857,30 €

Tab. 10-10 Annual production increase, annual revenues and annual intervention cost savings of the 20% of the wells equipped with new tubing material in the fourth year in the best case

Tubing string (Best case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	20,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	13.627,02 €	6.813,51 €
Total intervention costs/year (new) [Euro/year]:		34.426.394,86 €	34.426.394,86 €	34.426.394,86 €	20.655.836,92 €	10.327.918,46 €
Total intervention costs/year (old) [Euro/year]:		34.426.394,86 €	34.426.394,86 €	34.426.394,86 €	34.426.394,86 €	34.426.394,86 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	47,64	21,44
Total production losses/year [tons/year]:		165.103,55	148.593,19	133.733,87	72.216,29	32.497,33
Total production losses/year [bbl/year]:		1.210.209,00	1.089.188,10	980.269,29	529.345,42	238.205,44
Total oil production/year (old) [tons/year]:		662.228,51	596.005,66	536.405,10	482.764,59	434.488,13
Total oil production/year (old) [bbl/year]:		4.854.135,00	4.368.721,50	3.931.849,35	3.538.664,42	3.184.797,97
Production increase/year [bbl/year]:		0,00	0,00	0,00	352.896,94	555.812,69
Total oil production/year (new) [bbl/year]:		4.854.135,00	4.368.721,50	3.931.849,35	3.891.561,36	3.740.610,66
Revenues / year [Euro/year]:		218.436.075,00 €	196.592.467,50 €	176.933.220,75 €	175.120.261,17 €	168.327.479,74 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	13.770.557,94 €	24.098.476,40 €

Tab. 10-11 Annual production increase, annual revenues and annual intervention cost savings of the 20% of the wells equipped with new tubing material in the fifth year in the best case

Tubing string (Best case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	20,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	13.627,02 €
Total intervention costs/year (new) [Euro/year]:		34.426.394,86 €	34.426.394,86 €	34.426.394,86 €	34.426.394,86 €	20.655.836,92 €
Total intervention costs/year (old) [Euro/year]:		34.426.394,86 €	34.426.394,86 €	34.426.394,86 €	34.426.394,86 €	34.426.394,86 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	79,40	42,88
Total production losses/year [tons/year]:		165.103,55	148.593,19	133.733,87	120.360,49	64.994,66
Total production losses/year [bbl/year]:		1.210.209,00	1.089.188,10	980.269,29	882.242,36	476.410,87
Total oil production/year (old) [tons/year]:		662.228,51	596.005,66	536.405,10	482.764,59	434.488,13
Total oil production/year (old) [bbl/year]:		4.854.135,00	4.368.721,50	3.931.849,35	3.538.664,42	3.184.797,97
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	317.607,25
Total oil production/year (new) [bbl/year]:		4.854.135,00	4.368.721,50	3.931.849,35	3.538.664,42	3.502.405,22
Revenues / year [Euro/year]:		218.436.075,00 €	196.592.467,50 €	176.933.220,75 €	159.239.898,68 €	157.608.235,06 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	13.770.557,94 €

Tab. 10-12 Annual production increase, annual revenues and annual intervention cost savings of 15% of the wells which are not equipped with new tubing material in the best case

Tubing string (Best case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	15,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €
Total intervention costs/year (new) [Euro/year]:		25.019.796,15 €	25.019.796,15 €	25.019.796,15 €	25.019.796,15 €	25.019.796,15 €
Total intervention costs/year (old) [Euro/year]:		25.019.796,15 €	25.019.796,15 €	25.019.796,15 €	25.019.796,15 €	25.019.796,15 €
Production losses/well/year [tons/year]:		100,92	90,03	88,23	79,40	71,46
Total production losses/year [tons/year]:		123.827,66	111.444,89	100.300,40	90.270,36	81.243,33
Total production losses/year [bbl/year]:		907.656,75	816.891,08	735.201,97	661.681,77	595.513,59
Total oil production/year (old) [tons/year]:		496.671,38	447.004,25	402.303,82	362.073,44	325.866,10
Total oil production/year (old) [bbl/year]:		3.640.601,25	3.276.541,13	2.948.887,01	2.653.998,31	2.388.598,48
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	0,00
Total oil production/year (new) [bbl/year]:		3.640.601,25	3.276.541,13	2.948.887,01	2.653.998,31	2.388.598,48
Revenues / year [Euro/year]:		163.827.056,25 €	147.444.350,63 €	132.699.915,56 €	119.429.924,01 €	107.486.931,61 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	- €

Tab. 10-13 Annual production increase, annual revenues and annual intervention cost savings of the 5% of the wells equipped with new tubing material in the third year in the worst case

Tubing string (Worst case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	5,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	13.627,02 €	6.013,51 €	6.013,51 €
Total intervention costs/year (new) [Euro/year]:		8.606.598,72 €	8.606.598,72 €	5.163.959,23 €	2.581.979,61 €	2.581.979,61 €
Total intervention costs/year (old) [Euro/year]:		8.606.598,72 €	8.606.598,72 €	8.606.598,72 €	8.606.598,72 €	8.606.598,72 €
Production losses/well/year [tons/year]:		100,92	90,03	52,94	23,02	21,44
Total production losses/year [tons/year]:		41.275,89	37.148,30	20.080,08	9.027,04	8.124,33
Total production losses/year [bbl/year]:		302.552,25	272.297,03	147.040,39	66.168,18	59.551,36
Total oil production/year (old) [tons/year]:		165.557,13	149.001,42	134.101,27	120.691,15	108.622,03
Total oil production/year (old) [bbl/year]:		1.213.533,75	1.092.180,38	982.962,34	884.666,10	796.199,49
Production increase/year [bbl/year]:		0,00	0,00	98.026,93	154.392,41	138.953,17
Total oil production/year (new) [bbl/year]:		1.213.533,75	1.092.180,38	1.080.989,27	1.039.058,52	935.152,67
Revenues / year [Euro/year]:		56.609.018,75 €	49.148.116,88 €	48.644.516,99 €	46.757.633,36 €	42.081.860,94 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	3.442.639,49 €	6.024.619,10 €	6.024.619,10 €

Tab. 10-14 Annual production increase, annual revenues and annual intervention cost savings of the 7% of the wells equipped with new tubing material in the fourth year in the worst case

Tubing string (Worst case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	7,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	13.627,02 €	6.013,51 €
Total intervention costs/year (new) [Euro/year]:		12.049.238,20 €	12.049.238,20 €	12.049.238,20 €	7.229.542,92 €	3.614.771,46 €
Total intervention costs/year (old) [Euro/year]:		12.049.238,20 €	12.049.238,20 €	12.049.238,20 €	12.049.238,20 €	12.049.238,20 €
Production losses/well/year [tons/year]:		100,92	90,03	88,23	47,64	21,44
Total production losses/year [tons/year]:		57.786,24	52.007,62	46.806,86	25.275,70	11.374,07
Total production losses/year [bbl/year]:		423.573,15	381.215,84	343.094,25	185.270,90	83.371,80
Total oil production/year (old) [tons/year]:		231.779,90	208.601,90	187.741,78	168.967,61	152.070,84
Total oil production/year (old) [bbl/year]:		1.698.947,25	1.529.052,53	1.376.147,27	1.238.532,55	1.114.679,29
Production increase/year [bbl/year]:		0,00	0,00	0,00	173.513,93	194.534,44
Total oil production/year (new) [bbl/year]:		1.698.947,25	1.529.052,53	1.376.147,27	1.362.046,48	1.309.213,73
Revenues / year [Euro/year]:		76.452.626,25 €	68.807.363,63 €	61.926.627,26 €	61.292.091,41 €	58.914.617,91 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	4.819.695,28 €	8.434.466,74 €

Tab. 10-15 Annual production increase, annual revenues and annual intervention cost savings of the 7% of the wells equipped with new tubing material in the fifth year in the worst case

Tubing string (Worst case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	7,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	13.627,02 €
Total intervention costs/year (new) [Euro/year]:		12.049.238,20 €	12.049.238,20 €	12.049.238,20 €	12.049.238,20 €	7.229.542,92 €
Total intervention costs/year (old) [Euro/year]:		12.049.238,20 €	12.049.238,20 €	12.049.238,20 €	12.049.238,20 €	12.049.238,20 €
Production losses/well/year [tons/year]:		100,92	90,83	88,23	79,40	42,80
Total production losses/year [tons/year]:		57.786,24	52.007,62	46.806,86	42.126,17	22.740,13
Total production losses/year [bbl/year]:		423.573,15	381.215,84	343.094,25	308.784,83	166.743,81
Total oil production/year (old) [tons/year]:		231.779,90	208.601,90	187.741,78	168.967,61	152.070,84
Total oil production/year (old) [bbl/year]:		1.698.947,25	1.529.052,53	1.376.147,27	1.238.532,55	1.114.679,29
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	111.162,54
Total oil production/year (new) [bbl/year]:		1.698.947,25	1.529.052,53	1.376.147,27	1.238.532,55	1.225.841,83
Revenues / year [Euro/year]:		76.452.626,25 €	68.807.363,63 €	61.926.627,26 €	55.733.964,54 €	55.162.882,27 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	4.819.695,28 €

Tab. 10-16 Annual production increase, annual revenues and annual intervention cost savings of the 71% of the wells which are not equipped with new tubing material in the worst case

Tubing string (Worst case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	71,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €
Total intervention costs/year (new) [Euro/year]:		122.213.701,75 €	122.213.701,75 €	122.213.701,75 €	122.213.701,75 €	122.213.701,75 €
Total intervention costs/year (old) [Euro/year]:		122.213.701,75 €	122.213.701,75 €	122.213.701,75 €	122.213.701,75 €	122.213.701,75 €
Production losses/well/year [tons/year]:		100,92	90,83	88,23	79,40	71,46
Total production losses/year [tons/year]:		586.117,59	527.505,83	474.755,25	427.279,72	384.551,75
Total production losses/year [bbl/year]:		4.296.241,95	3.866.617,76	3.479.955,98	3.131.960,38	2.818.764,34
Total oil production/year (old) [tons/year]:		2.350.911,22	2.115.820,10	1.904.238,09	1.713.814,28	1.542.432,85
Total oil production/year (old) [bbl/year]:		17.232.179,25	15.508.961,33	13.958.065,19	12.562.258,67	11.306.032,81
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	0,00
Total oil production/year (new) [bbl/year]:		17.232.179,25	15.508.961,33	13.958.065,19	12.562.258,67	11.306.032,81
Revenues / year [Euro/year]:		775.448.066,25 €	697.903.259,63 €	628.112.933,66 €	565.301.640,30 €	508.771.476,27 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	- €

Tab. 10-17 Annual production increase, annual revenues and annual intervention cost savings of the 10% of the wells equipped with new tubings in the third year in the most realistic case

Tubing string (Most realistic case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	10,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	13.627,02 €	6.813,51 €	6.813,51 €
Total intervention costs/year (new) [Euro/year]:		17.213.197,43 €	17.213.197,43 €	10.327.918,46 €	5.163.959,23 €	5.163.959,23 €
Total intervention costs/year (old) [Euro/year]:		17.213.197,43 €	17.213.197,43 €	17.213.197,43 €	17.213.197,43 €	17.213.197,43 €
Production losses/well/year [tons/year]:		100,92	90,83	52,94	23,82	21,44
Total production losses/year [tons/year]:		82.551,77	74.296,60	40.120,18	18.054,07	16.248,67
Total production losses/year [bbl/year]:		605.104,50	544.594,05	294.080,79	132.336,35	119.102,72
Total oil production/year (old) [tons/year]:		331.114,26	298.002,83	268.202,55	241.382,29	217.244,06
Total oil production/year (old) [bbl/year]:		2.427.067,50	2.184.360,75	1.965.924,68	1.769.332,21	1.592.398,99
Production increase/year [bbl/year]:		0,00	0,00	196.053,85	308.784,83	277.906,34
Total oil production/year (new) [bbl/year]:		2.427.067,50	2.184.360,75	2.161.978,53	2.078.117,03	1.870.305,33
Revenues / year [Euro/year]:		109.218.037,50 €	98.296.233,75 €	97.289.033,99 €	93.515.266,52 €	84.163.739,87 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	6.885.278,97 €	12.049.238,20 €	12.049.238,20 €

Tab. 10-18 Annual production increase, annual revenues and annual intervention cost savings of the 15% of the wells equipped with new tubing material in the fourth year most realsitic case

Tubing string (Most realistic case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	15,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	13.627,02 €	6.813,51 €
Total intervention costs/year (new) [Euro/year]:		25.019.798,15 €	25.019.798,15 €	25.019.798,15 €	15.491.877,69 €	7.745.938,84 €
Total intervention costs/year (old) [Euro/year]:		25.019.798,15 €	25.019.798,15 €	25.019.798,15 €	25.019.798,15 €	25.019.798,15 €
Production losses/well/year [tons/year]:		100,92	90,83	81,73	47,64	21,44
Total production losses/year [tons/year]:		123827,86	111444,89	100300,40	54182,22	24373,00
Total production losses/year [bbl/year]:		907656,75	816891,00	735201,97	397008,06	178654,00
Total oil production/year (old) [tons/year]:		496671,30	447004,25	402303,82	362073,44	325866,10
Total oil production/year (old) [bbl/year]:		3640601,25	3276541,13	2948887,01	2653998,31	2388598,40
Production increase/year [bbl/year]:		0,00	0,00	0,00	264672,71	416859,52
Total oil production/year (new) [bbl/year]:		3640601,25	3276541,13	2948887,01	2918671,02	2805458,00
Revenues / year [Euro/year]:		163.827.056,25 €	147.444.350,63 €	132.699.915,56 €	131.340.195,88 €	126.245.609,01 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	10.327.918,46 €	18.073.857,30 €

Tab. 10-19 Annual production increase, annual revenues and annual intervention cost savings of the 15% of the wells equipped with new tubing material in the fifth year in the most realistic case

Tubing string (Most realistic case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	15,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	13.627,02 €
Total intervention costs/year (new) [Euro/year]:		25.019.798,15 €	25.019.798,15 €	25.019.798,15 €	25.019.798,15 €	15.491.877,69 €
Total intervention costs/year (old) [Euro/year]:		25.019.798,15 €	25.019.798,15 €	25.019.798,15 €	25.019.798,15 €	25.019.798,15 €
Production losses/well/year [tons/year]:		100,92	90,83	81,73	79,40	42,88
Total production losses/year [tons/year]:		123.827,86	111.444,89	100.300,40	90.270,36	48.746,00
Total production losses/year [bbl/year]:		907.656,75	816.891,00	735.201,97	661.681,77	357.208,16
Total oil production/year (old) [tons/year]:		496.671,30	447.004,25	402.303,82	362.073,44	325.866,10
Total oil production/year (old) [bbl/year]:		3.640.601,25	3.276.541,13	2.948.887,01	2.653.998,31	2.388.598,40
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	238.205,44
Total oil production/year (new) [bbl/year]:		3.640.601,25	3.276.541,13	2.948.887,01	2.653.998,31	2.626.803,92
Revenues / year [Euro/year]:		163.827.056,25 €	147.444.350,63 €	132.699.915,56 €	119.428.924,01 €	118.206.176,20 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	10.327.918,46 €

Tab. 10-20 Annual production increase, annual revenues and annual intervention cost savings of 40% of the wells which are not equipped with new tubing material in the most realistic case

Tubing string (Most realistic case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	40,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €
Total intervention costs/year (new) [Euro/year]:		60.052.709,72 €	60.052.709,72 €	60.052.709,72 €	60.052.709,72 €	60.052.709,72 €
Total intervention costs/year (old) [Euro/year]:		60.052.709,72 €	60.052.709,72 €	60.052.709,72 €	60.052.709,72 €	60.052.709,72 €
Production losses/well/year [tons/year]:		100,92	90,83	81,73	79,40	71,46
Total production losses/year [tons/year]:		330.207,09	297.186,30	267.467,75	240.720,97	216.648,87
Total production losses/year [bbl/year]:		2.420.410,00	2.178.376,20	1.960.538,58	1.764.484,72	1.588.036,25
Total oil production/year (old) [tons/year]:		1.324.457,03	1.192.011,32	1.072.810,19	965.529,17	868.976,25
Total oil production/year (old) [bbl/year]:		9.708.270,00	8.737.443,00	7.863.698,70	7.077.328,83	6.369.595,95
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	0,00
Total oil production/year (new) [bbl/year]:		9.708.270,00	8.737.443,00	7.863.698,70	7.077.328,83	6.369.595,95
Revenues / year [Euro/year]:		436.872.150,00 €	393.184.935,00 €	353.866.441,50 €	318.479.797,35 €	280.631.817,62 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	- €

Fig. 10-4 Total oil production [bbl] for different tubing material scenarios

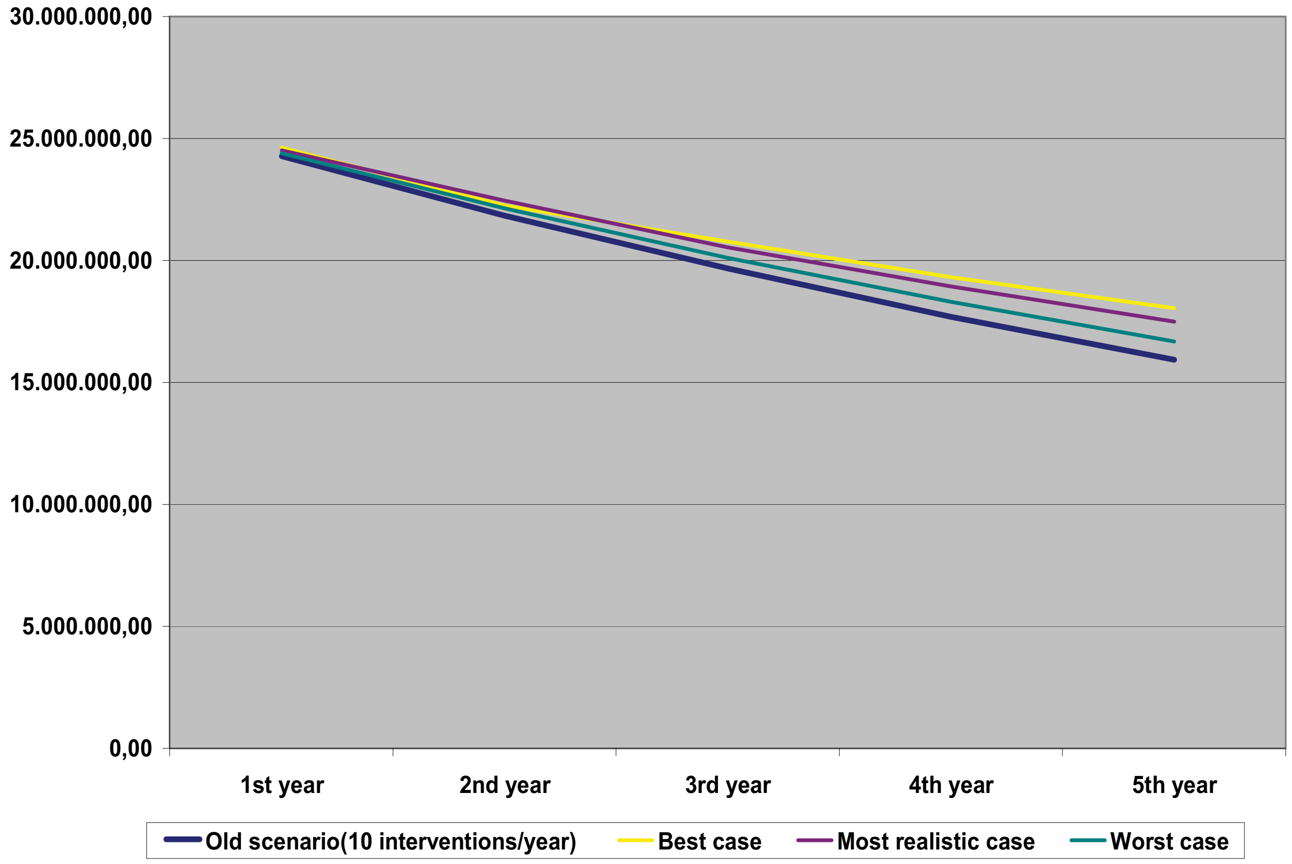


Fig. 10-5 Annual production increase [bbl] for different tubing material scenarios

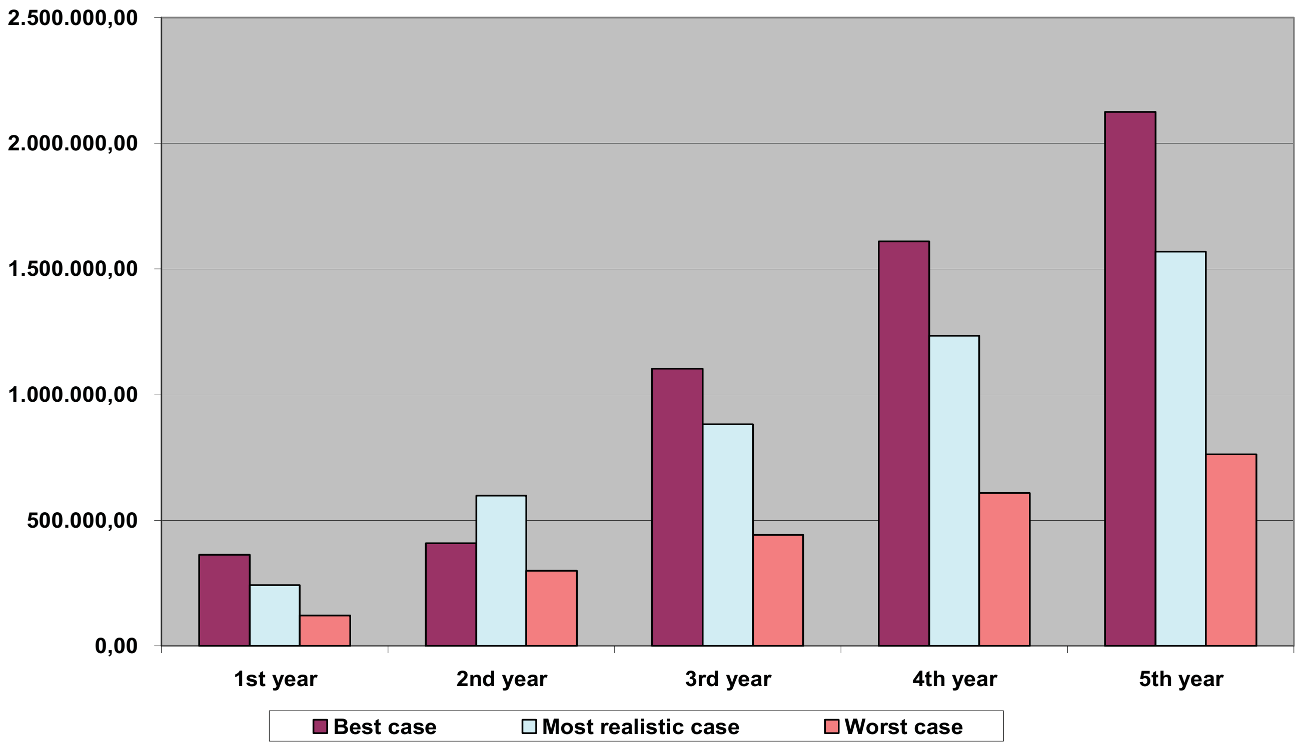
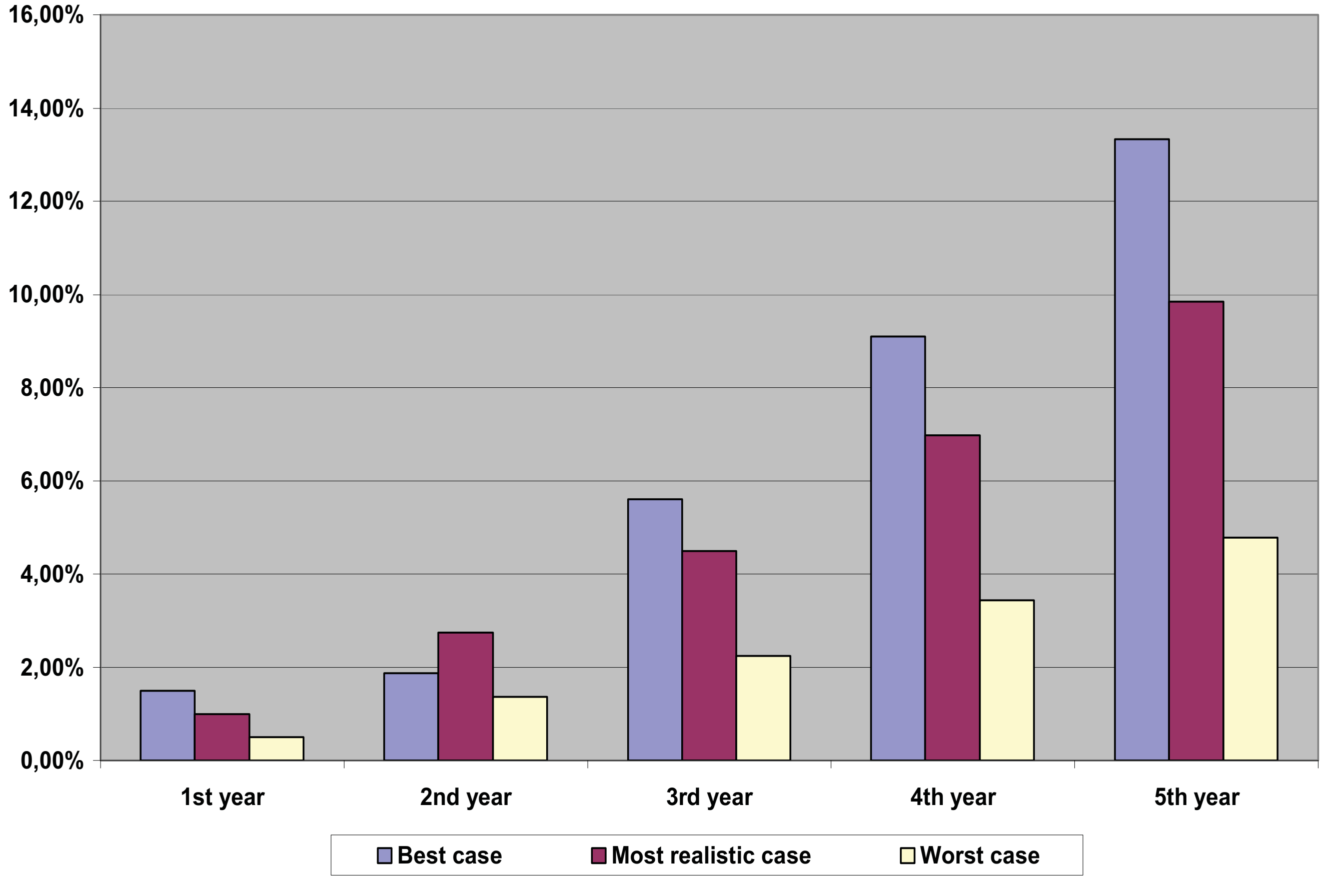


Fig. 10-6 Annual production increase in percent for different tubing material scenarios



Tab. 10-21 Difference in the net present value for the most realsitic case

Tubing string (Most realistic case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Annual revenues due to the oil production [Euro/year]:	1.213.533.750,00 €	1.103.077.256,00 €	1.009.919.747,98 €	924.367.010,00 €	851.780.782,17 €	787.147.984,89 €
Annual savings due to reduced interventions [Euro/year]:		6.085.270,97 €	18.934.517,17 €	30.903.755,37 €	48.198.852,80 €	67.992.170,85 €
Tubing costs [Euro/year]:	31.803.909,28 €	32.675.494,28 €	31.273.379,28 €	38.702.643,92 €	37.796.321,42 €	35.693.148,92 €
Annual cash flow(Best case)[Euro/year]:	1.181.729.840,72 €	1.077.282.040,69 €	997.580.880,87 €	916.588.121,45 €	862.181.393,50 €	819.446.885,82 €
Annual discounted cash flow(10interventions/year)[Euro/year]:	1.213.533.750,00 €	983.946.283,78 €	797.794.284,15 €	646.860.230,39 €	524.481.267,88 €	425.255.082,07 €
Annual discounted cash flow(Best case)[Euro/year]:		970.524.360,98 €	809.659.021,89 €	670.201.334,61 €	567.945.589,23 €	486.301.842,86 €
Net present value (10 interventions per year)[Euro/year]:		2.197.480.033,78 €	2.995.274.317,93 €	3.642.134.548,32 €	4.166.615.816,21 €	4.591.870.898,28 €
Net present value (Best case)[Euro/year]:		2.152.254.201,70 €	2.961.913.223,59 €	3.632.114.558,20 €	4.200.060.147,43 €	4.686.361.990,09 €
Difference in net present value [Euro/year]:	- 31.803.909,28 €	- 45.225.832,08 €	- 33.361.094,34 €	- 10.019.990,13 €	33.444.331,22 €	94.491.091,91 €

Tab. 10-22 Difference in the net present value for the worst case

Tubing string (Worst case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Annual revenues due to the oil production [Euro/year]:	1.213.533.750,00 €	1.097.876.315,50 €	996.441.040,24 €	904.516.556,87 €	823.593.110,60 €	750.881.127,03 €
Annual savings due to reduced interventions [Euro/year]:		3.442.639,49 €	9.467.258,59 €	15.491.877,69 €	23.794.212,45 €	33.049.339,07 €
Tubing costs [Euro/year]:	22.912.529,64 €	23.348.322,14 €	22.647.264,64 €	25.502.759,00 €	24.976.918,50 €	23.994.538,00 €
Annual cash flow(Best case)[Euro/year]:	1.190.621.220,36 €	1.077.720.632,85 €	983.261.034,18 €	894.505.675,56 €	822.371.312,84 €	759.935.928,10 €
Annual discounted cash flow(10interventions/year)[Euro/year]:	1.213.533.750,00 €	983.946.283,78 €	797.794.284,15 €	646.860.230,39 €	524.481.267,88 €	425.255.082,07 €
Annual discounted cash flow(Best case)[Euro/year]:		970.919.489,05 €	798.036.712,08 €	654.054.840,50 €	541.721.455,80 €	450.984.985,77 €
Net present value (10 interventions per year)[Euro/year]:		2.197.480.033,78 €	2.995.274.317,93 €	3.642.134.548,32 €	4.166.615.816,21 €	4.591.870.898,28 €
Net present value (Best case)[Euro/year]:		2.161.540.709,41 €	2.960.577.422,49 €	3.613.632.262,99 €	4.155.353.718,87 €	4.606.338.704,64 €
Difference in net present value [Euro/year]:	- 22.912.529,64 €	- 35.939.324,37 €	- 35.696.895,44 €	- 28.502.285,34 €	- 11.262.097,34 €	14.467.806,37 €

Tab. 10-23 Annual production increase, annual revenues and annual intervention cost savings of the 15% of the wells equipped with new sucker rod strings in the third year in the best case

Sucker rod string (Best case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	15,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	17.033,78 €	11.355,85 €	11.355,85 €
Total intervention costs/year (new) [Euro/year]:		25.819.796,15 €	25.819.796,15 €	19.364.847,11 €	12.909.898,07 €	12.909.898,07 €
Total intervention costs/year (old) [Euro/year]:		25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €
Production losses/well/year [tons/year]:		108,92	98,03	66,17	39,70	35,73
Total production losses/year [tons/year]:		123.827,86	111.444,89	75.225,30	45.135,18	40.621,66
Total production losses/year [bbl/year]:		907.856,75	816.891,08	551.401,48	330.840,89	297.756,80
Total oil production/year (old) [tons/year]:		496.671,38	447.004,25	402.303,82	362.073,44	325.866,10
Total oil production/year (old) [bbl/year]:		3.640.601,25	3.276.541,13	2.948.887,01	2.653.998,31	2.388.598,48
Production increase/year [bbl/year]:		0,00	0,00	183.800,49	330.840,89	297.756,80
Total oil production/year (new) [bbl/year]:		3.640.601,25	3.276.541,13	3.132.687,50	2.984.839,20	2.686.355,28
Revenues / year [Euro/year]:		163.827.056,25 €	147.444.350,63 €	140.970.937,70 €	134.317.763,85 €	120.885.987,46 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	6.454.949,04 €	12.909.898,07 €	12.909.898,07 €

Tab. 10-24 Annual production increase, annual revenues and annual intervention cost savings of the 20% of the wells equipped with new sucker rod strings in the fourth year in the best case

Sucker rod string (Best case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	20,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	17.033,78 €	11.355,85 €
Total intervention costs/year (new) [Euro/year]:		34.426.394,86 €	34.426.394,86 €	34.426.394,86 €	25.819.796,15 €	17.213.197,43 €
Total intervention costs/year (old) [Euro/year]:		34.426.394,86 €	34.426.394,86 €	34.426.394,86 €	34.426.394,86 €	34.426.394,86 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	59,55	35,73
Total production losses/year [tons/year]:		165.103,55	148.593,19	133.733,87	90.270,36	54.162,22
Total production losses/year [bbl/year]:		1.210.209,00	1.089.188,10	980.269,29	661.681,77	397.009,06
Total oil production/year (old) [tons/year]:		662.228,51	596.005,66	536.405,10	482.764,59	434.488,13
Total oil production/year (old) [bbl/year]:		4.854.135,00	4.368.721,50	3.931.849,35	3.538.664,42	3.184.797,97
Production increase/year [bbl/year]:		0,00	0,00	0,00	220.560,59	397.009,06
Total oil production/year (new) [bbl/year]:		4.854.135,00	4.368.721,50	3.931.849,35	3.759.225,01	3.581.807,04
Revenues / year [Euro/year]:		218.436.075,00 €	196.592.467,50 €	176.933.220,75 €	169.165.125,24 €	161.181.316,62 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	8.606.598,72 €	17.213.197,43 €

Tab. 10-25 Annual production increase, annual revenues and annual intervention cost savings of the 20% of the wells equipped with new sucker rod strings in the fifth year in the best case

Sucker rod string (Best case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	20,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	17.033,78 €
Total intervention costs/year (new) [Euro/year]:		34.426.394,06 €	34.426.394,06 €	34.426.394,06 €	34.426.394,06 €	25.819.796,15 €
Total intervention costs/year (old) [Euro/year]:		34.426.394,06 €	34.426.394,06 €	34.426.394,06 €	34.426.394,06 €	34.426.394,06 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	79,40	53,60
Total production losses/year [tons/year]:		165.103,55	148.593,19	133.733,87	120.360,49	81.243,13
Total production losses/year [bbl/year]:		1.210.209,00	1.089.188,10	980.269,29	882.242,36	595.513,59
Total oil production/year (old) [tons/year]:		662.228,51	596.005,66	536.405,10	482.764,59	434.488,13
Total oil production/year (old) [bbl/year]:		4.854.135,00	4.368.721,50	3.931.849,35	3.538.664,42	3.184.797,97
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	198.504,53
Total oil production/year (new) [bbl/year]:		4.854.135,00	4.368.721,50	3.931.849,35	3.538.664,42	3.383.302,50
Revenues / year [Euro/year]:		218.436.075,00 €	196.592.467,50 €	176.933.220,75 €	159.239.898,68 €	152.248.612,71 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	8.606.598,72 €

Tab. 10-26 Annual production increase, annual revenues and annual intervention cost savings of the 15% of the wells which are not equipped with new sucker rod strings in the best case

Sucker rod string (Best case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	15,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €
Total intervention costs/year (new) [Euro/year]:		25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €
Total intervention costs/year (old) [Euro/year]:		25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	79,40	71,46
Total production losses/year [tons/year]:		165.103,55	148.593,19	133.733,87	120.360,49	108.324,44
Total production losses/year [bbl/year]:		1.210.209,00	1.089.188,10	980.269,29	882.242,36	794.018,12
Total oil production/year (old) [tons/year]:		496.671,38	447.004,25	402.303,82	362.073,44	325.866,10
Total oil production/year (old) [bbl/year]:		3.640.601,25	3.276.541,13	2.948.887,01	2.653.998,31	2.388.598,48
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	0,00
Total oil production/year (new) [bbl/year]:		3.640.601,25	3.276.541,13	2.948.887,01	2.653.998,31	2.388.598,48
Revenues / year [Euro/year]:		163.827.056,25 €	147.444.350,63 €	132.699.915,56 €	119.429.924,01 €	107.486.931,61 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	- €

Tab. 10-27 Annual production increase, annual revenues and annual intervention cost savings of the 5% of the wells equipped with new sucker rod strings in the third year in the worst case

Sucker rod string (Worst case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	5,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	17.033,78 €	11.355,85 €	11.355,85 €
Total intervention costs/year (new) [Euro/year]:		8.606.598,72 €	8.606.598,72 €	6.454.949,04 €	4.303.299,36 €	4.303.299,36 €
Total intervention costs/year (old) [Euro/year]:		8.606.598,72 €	8.606.598,72 €	8.606.598,72 €	8.606.598,72 €	8.606.598,72 €
Production losses/well/year [tons/year]:		108,92	98,03	66,17	39,70	35,73
Total production losses/year [tons/year]:		41.275,89	37.148,30	25.075,10	15.045,06	13.540,55
Total production losses/year [bbl/year]:		302.552,25	272.297,03	183.800,49	110.280,30	99.252,27
Total oil production/year (old) [tons/year]:		165.557,13	149.001,42	134.101,27	120.691,15	108.622,03
Total oil production/year (old) [bbl/year]:		1.213.533,75	1.092.180,38	982.962,34	884.666,10	796.199,49
Production increase/year [bbl/year]:		0,00	0,00	61.266,83	110.280,30	99.252,27
Total oil production/year (new) [bbl/year]:		1.213.533,75	1.092.180,38	1.044.229,17	994.946,40	895.451,76
Revenues / year [Euro/year]:		54.609.018,75 €	49.148.116,88 €	46.990.312,57 €	44.772.587,85 €	40.295.329,15 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	2.151.649,68 €	4.303.299,36 €	4.303.299,36 €

Tab. 10-28 Annual production increase, annual revenues and annual intervention cost savings of the 7% of the wells equipped with new sucker rod strings in the fourth year in the worst case

Sucker rod string (Worst case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	7,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	17.033,78 €	11.355,85 €
Total intervention costs/year (new) [Euro/year]:		12.049.230,20 €	12.049.230,20 €	12.049.230,20 €	9.036.928,65 €	6.024.619,10 €
Total intervention costs/year (old) [Euro/year]:		12.049.230,20 €	12.049.230,20 €	12.049.230,20 €	12.049.230,20 €	12.049.230,20 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	59,55	35,73
Total production losses/year [tons/year]:		57.786,24	52.007,62	46.806,86	31.594,63	18.956,78
Total production losses/year [bbl/year]:		423.573,15	381.215,84	343.094,25	231.588,62	138.953,17
Total oil production/year (old) [tons/year]:		231.779,98	208.601,98	187.741,78	168.967,61	152.070,84
Total oil production/year (old) [bbl/year]:		1.698.947,25	1.529.052,53	1.376.147,27	1.238.532,55	1.114.679,29
Production increase/year [bbl/year]:		0,00	0,00	0,00	77.196,21	138.953,17
Total oil production/year (new) [bbl/year]:		1.698.947,25	1.529.052,53	1.376.147,27	1.315.728,75	1.253.632,46
Revenues / year [Euro/year]:		76.452.626,25 €	68.807.363,63 €	61.926.627,26 €	59.207.793,83 €	56.413.460,82 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	3.012.308,55 €	6.024.619,10 €

Tab. 10-29 Annual production increase, annual revenues and annual intervention cost savings of the 7% of the wells equipped with new sucker rod strings in the fifth year in the worst case

Sucker rod string (Worst case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	7,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	17.033,78 €
Total intervention costs/year (new) [Euro/year]:		12.049.230,20 €	12.049.230,20 €	12.049.230,20 €	12.049.230,20 €	9.036.928,65 €
Total intervention costs/year (old) [Euro/year]:		12.049.230,20 €	12.049.230,20 €	12.049.230,20 €	12.049.230,20 €	12.049.230,20 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	79,40	53,60
Total production losses/year [tons/year]:		57.786,24	52.007,62	46.806,86	42.126,17	28.435,16
Total production losses/year [bbl/year]:		423.573,15	381.215,84	343.094,25	308.784,03	208.429,76
Total oil production/year (old) [tons/year]:		231.779,98	208.601,98	187.741,78	168.967,61	152.070,84
Total oil production/year (old) [bbl/year]:		1.698.947,25	1.529.052,53	1.376.147,27	1.238.532,55	1.114.679,29
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	69.476,59
Total oil production/year (new) [bbl/year]:		1.698.947,25	1.529.052,53	1.376.147,27	1.238.532,55	1.184.155,88
Revenues / year [Euro/year]:		76.452.626,25 €	68.807.363,63 €	61.926.627,26 €	55.733.964,54 €	53.287.014,45 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	3.012.308,55 €

Tab. 10-30 Annual production increase, annual revenues and annual intervention cost savings of the 71% of the wells which are not equipped with new sucker rod strings in the worst case

Sucker rod string (Worst case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	71,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €
Total intervention costs/year (new) [Euro/year]:		122.213.701,75 €	122.213.701,75 €	122.213.701,75 €	122.213.701,75 €	122.213.701,75 €
Total intervention costs/year (old) [Euro/year]:		122.213.701,75 €	122.213.701,75 €	122.213.701,75 €	122.213.701,75 €	122.213.701,75 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	79,40	71,46
Total production losses/year [tons/year]:		586.117,59	527.505,83	474.755,25	427.279,72	384.551,75
Total production losses/year [bbl/year]:		4.296.241,95	3.866.617,76	3.479.955,98	3.131.960,38	2.818.764,34
Total oil production/year (old) [tons/year]:		2.350.911,22	2.115.820,10	1.904.238,09	1.713.814,28	1.542.432,85
Total oil production/year (old) [bbl/year]:		17.232.179,25	15.508.961,33	13.958.065,19	12.562.258,67	11.306.032,81
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	0,00
Total oil production/year (new) [bbl/year]:		17.232.179,25	15.508.961,33	13.958.065,19	12.562.258,67	11.306.032,81
Revenues / year [Euro/year]:		775.448.066,25 €	697.903.259,63 €	628.112.933,66 €	565.301.640,30 €	508.771.476,27 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	- €

Tab. 10-31 Annual production increase, annual revenues and annual intervention cost savings of the 10% of the wells equipped with new sucker rods in the third year in the most realistic case

Sucker rod string (Most realistic case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	10,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	17.033,78 €	11.355,85 €	11.355,85 €
Total intervention costs/year (new) [Euro/year]:		17.213.197,43 €	17.213.197,43 €	12.909.898,07 €	8.606.598,72 €	8.606.598,72 €
Total intervention costs/year (old) [Euro/year]:		17.213.197,43 €	17.213.197,43 €	17.213.197,43 €	17.213.197,43 €	17.213.197,43 €
Production losses/well/year [tons/year]:		108,92	98,03	66,17	39,70	35,73
Total production losses/year [tons/year]:		82.551,77	74.296,60	50.150,20	30.090,12	27.081,11
Total production losses/year [bbl/year]:		605.104,50	544.594,05	367.600,98	220.560,59	198.504,53
Total oil production/year (old) [tons/year]:		331.114,26	298.002,83	268.202,55	241.382,29	217.244,06
Total oil production/year (old) [bbl/year]:		2.427.067,50	2.184.360,75	1.965.924,68	1.769.332,21	1.592.398,99
Production increase/year [bbl/year]:		0,00	0,00	122.533,66	220.560,59	198.504,53
Total oil production/year (new) [bbl/year]:		2.427.067,50	2.184.360,75	2.088.458,34	1.989.892,80	1.790.903,52
Revenues / year [Euro/year]:		109.218.037,50 €	98.296.233,75 €	93.980.625,13 €	89.545.175,90 €	80.590.658,31 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	4.303.299,36 €	8.606.598,72 €	8.606.598,72 €

Tab. 10-32 Annual production increase, annual revenues and annual intervention cost savings of the 15% of the wells equipped with new sucker rods in the fourth year in the most realistic case

Sucker rod string (Most realistic case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	15,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	17.033,78 €	11.355,85 €
Total intervention costs/year (new) [Euro/year]:		25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	19.364.847,11 €	12.909.898,07 €
Total intervention costs/year (old) [Euro/year]:		25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	58,55	35,73
Total production losses/year [tons/year]:		123.827,66	111.444,89	100.300,40	67.702,77	40.621,66
Total production losses/year [bbl/year]:		907.656,75	816.891,08	735.201,97	496.261,33	297.756,80
Total oil production/year (old) [tons/year]:		496.671,38	447.004,25	402.303,82	362.073,44	325.866,10
Total oil production/year (old) [bbl/year]:		3.640.601,25	3.276.541,13	2.948.887,01	2.653.998,31	2.388.598,48
Production increase/year [bbl/year]:		0,00	0,00	0,00	165.420,44	297.756,80
Total oil production/year (new) [bbl/year]:		3.640.601,25	3.276.541,13	2.948.887,01	2.819.418,75	2.686.355,28
Revenues / year [Euro/year]:		163.827.056,25 €	147.444.350,63 €	132.699.915,56 €	126.873.843,83 €	120.885.987,46 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	6.454.949,04 €	12.909.898,07 €

Tab. 10-33 Annual production increase, annual revenues and annual intervention cost savings of the 15% of the wells equipped with new sucker rods in the fifth year in the most realistic case

Sucker rod string (Most realistic case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	15,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	17.033,78 €
Total intervention costs/year (new) [Euro/year]:		25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	19.364.847,11 €
Total intervention costs/year (old) [Euro/year]:		25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €	25.819.796,15 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	79,40	53,60
Total production losses/year [tons/year]:		123.827,66	111.444,89	100.300,40	90.270,36	60.932,50
Total production losses/year [bbl/year]:		907.656,75	816.891,08	735.201,97	661.681,77	446.635,20
Total oil production/year (old) [tons/year]:		496.671,38	447.004,25	402.303,82	362.073,44	325.866,10
Total oil production/year (old) [bbl/year]:		3.640.601,25	3.276.541,13	2.948.887,01	2.653.998,31	2.388.598,48
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	148.878,40
Total oil production/year (new) [bbl/year]:		3.640.601,25	3.276.541,13	2.948.887,01	2.653.998,31	2.537.476,88
Revenues / year [Euro/year]:		163.827.056,25 €	147.444.350,63 €	132.699.915,56 €	119.429.924,01 €	114.186.459,53 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	6.454.949,04 €

Tab. 10-34 Annual production increase, annual revenues and annual intervention cost savings of 40% of the wells which are not equipped with new sucker rod strings in the most realistic case

Sucker rod string (Most realistic case)	Percentage of wells	1st year	2nd year	3rd year	4th year	5th year
For	40,00%	of the wells:				
Intervention costs/well/year [Euro/year]:		22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €	22.711,70 €
Total intervention costs/year (new) [Euro/year]:		68.852.709,72 €	68.852.709,72 €	68.852.709,72 €	68.852.709,72 €	68.852.709,72 €
Total intervention costs/year (old) [Euro/year]:		68.852.709,72 €	68.852.709,72 €	68.852.709,72 €	68.852.709,72 €	68.852.709,72 €
Production losses/well/year [tons/year]:		108,92	98,03	88,23	79,40	71,46
Total production losses/year [tons/year]:		330.207,09	297.186,38	267.467,75	240.720,97	216.648,87
Total production losses/year [bbl/year]:		2.420.418,00	2.178.376,20	1.960.538,58	1.764.484,72	1.588.036,25
Total oil production/year (old) [tons/year]:		1.324.457,03	1.192.011,32	1.072.810,19	965.529,17	868.976,25
Total oil production/year (old) [bbl/year]:		9.708.270,00	8.737.443,00	7.863.698,70	7.077.328,83	6.369.595,95
Production increase/year [bbl/year]:		0,00	0,00	0,00	0,00	0,00
Total oil production/year (new) [bbl/year]:		9.708.270,00	8.737.443,00	7.863.698,70	7.077.328,83	6.369.595,95
Revenues / year [Euro/year]:		436.872.150,00 €	393.184.935,00 €	353.866.441,50 €	318.479.797,35 €	286.631.817,62 €
Savings due to reduced interventions/year[Euro/year]:		- €	- €	- €	- €	- €

Fig. 10-7 Total oil production [bbl] for different sucker rod string scenarios

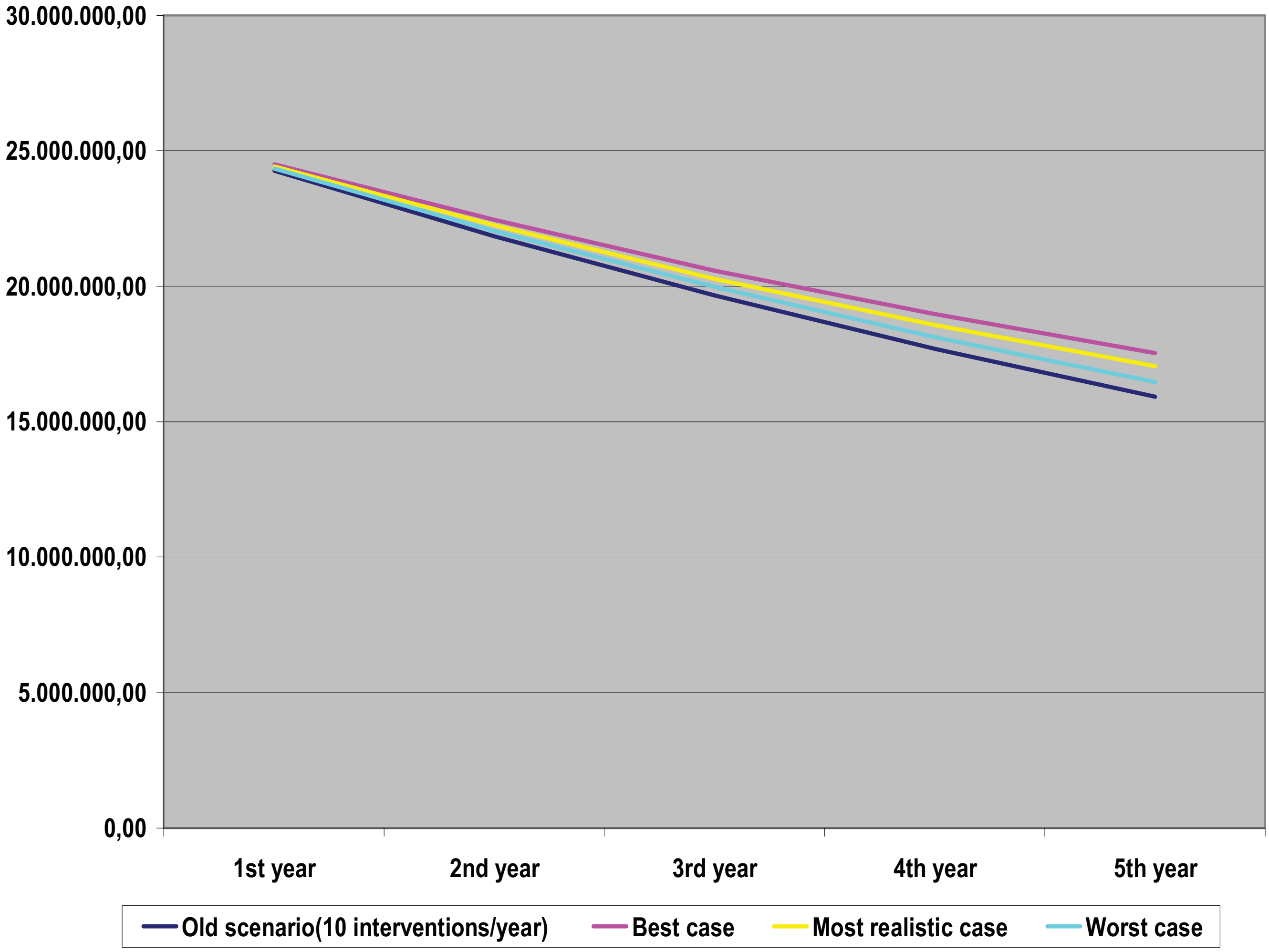


Fig. 10-8 Annual production increase [bbl] for different sucker rod string scenarios

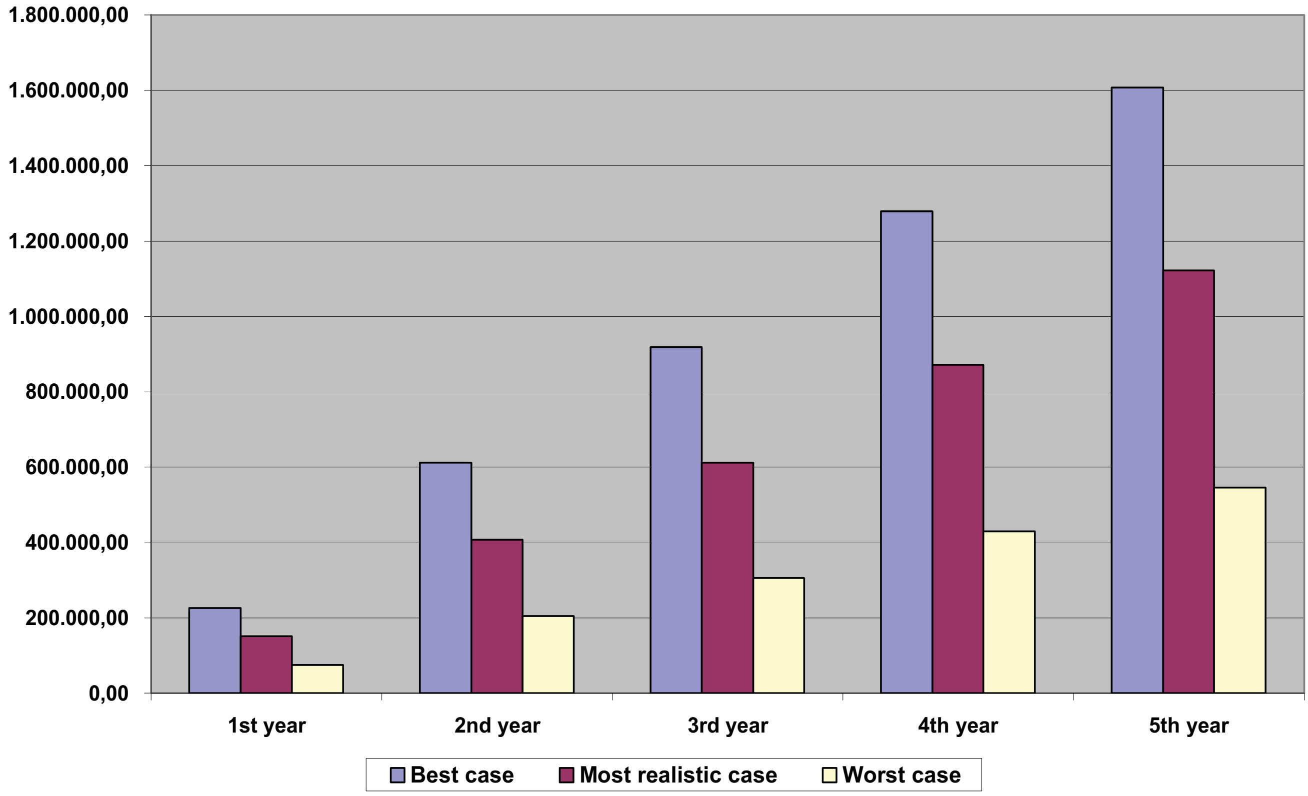
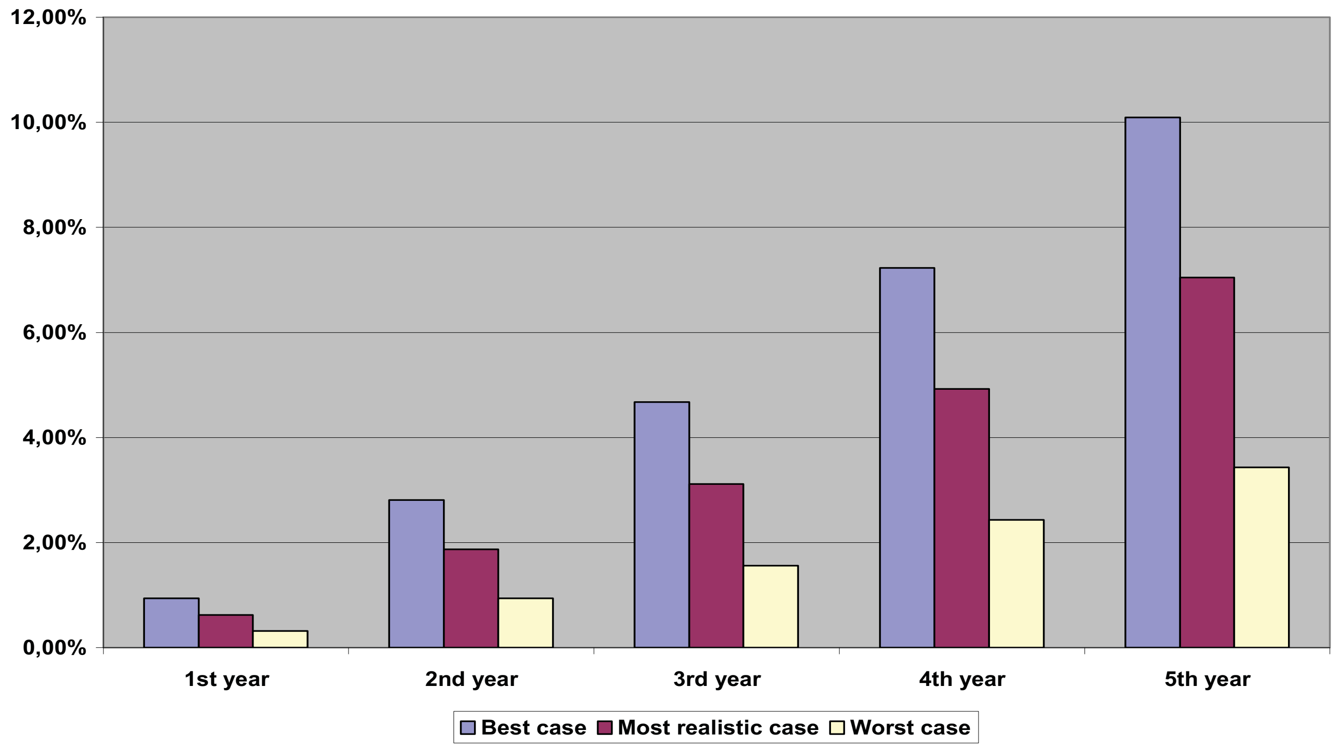


Fig. 10-9 Annual production increase in percent for different sucker rod string scenarios



Tab. 10-35 Difference in the net present value for the most realistic case

Sucker rod string (Most realsitic case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Annual revenues due to the oil production [Euro/year]	1.213.533.750,00 €	1.098.987.000,63 €	1.001.342.386,69 €	912.236.177,53 €	835.404.138,79 €	767.049.371,10 €
Annual savings due to reduced interventions [Euro/year]		4.303.296,36 €	12.909.888,07 €	21.516.486,79 €	33.996.064,92 €	40.627.282,74 €
Sucker rod string costs [Euro/year]	14.672.944,00 €	13.939.296,80 €	13.205.649,60 €	16.140.238,40 €	15.939.767,80 €	13.939.296,80 €
Annual cash flow(Most realistic case case)[Euro/year]	1.198.860.806,00 €	1.089.351.803,19 €	1.001.046.625,16 €	917.612.425,92 €	854.360.435,02 €	801.737.307,04 €
Annual discounted cash flow(10interventions/year)[Euro/year]	1.213.533.750,00 €	983.946.283,78 €	797.794.284,15 €	646.860.230,39 €	524.481.267,89 €	425.255.082,07 €
Annual discounted cash flow(Most realistic case)[Euro/year]	1.198.860.806,00 €	981.398.020,89 €	812.471.905,82 €	670.860.304,52 €	562.793.682,02 €	475.792.009,02 €
Net present value (10 interventions per year)[Euro/year]		2.197.480.033,78 €	2.995.274.317,93 €	3.642.134.548,32 €	4.166.615.816,21 €	4.591.870.898,28 €
Net present value (Most realistic case)[Euro/year]		2.180.258.826,89 €	2.992.730.732,70 €	3.663.481.037,22 €	4.226.474.719,25 €	4.702.266.728,86 €
Difference in net present value [Euro/year]	- 14.672.944,00 €	- 17.221.206,90 €	- 2.543.585,23 €	21.346.488,90 €	59.858.903,04 €	110.395.830,58 €

Tab. 10-36 Difference in the net present value for the worst case

Sucker rod string (Worst case)	Year before 1st year	1st year	2nd year	3rd year	4th year	5th year
Annual revenues due to the oil production [Euro/year]	1.213.533.750,00 €	1.095.584.087,81 €	992.152.387,09 €	898.451.140,64 €	815.553.885,17 €	741.144.479,78 €
Annual savings due to reduced interventions [Euro/year]		2.151.649,68 €	6.454.949,04 €	10.758.248,39 €	16.702.067,49 €	23.888.146,47 €
Sucker rod string costs [Euro/year]	11.004.708,00 €	10.637.884,40 €	10.271.060,80 €	11.371.531,80 €	10.857.978,56 €	10.344.425,52 €
Annual cash flow(Worst case)[Euro/year]	1.202.529.042,00 €	1.087.097.853,09 €	988.336.250,33 €	897.837.857,43 €	821.478.574,10 €	754.468.200,72 €
Annual discounted cash flow(10interventions/year)[Euro/year]	1.213.533.750,00 €	983.946.283,78 €	797.794.284,15 €	646.860.230,39 €	524.481.267,89 €	425.255.082,07 €
Annual discounted cash flow(Worst case)[Euro/year]	1.202.529.042,00 €	979.367.435,22 €	802.155.872,36 €	656.491.303,16 €	541.133.381,36 €	447.740.155,70 €
Net present value (10 interventions per year)[Euro/year]		2.197.480.033,78 €	2.995.274.317,93 €	3.642.134.548,32 €	4.166.615.816,21 €	4.591.870.898,28 €
Net present value (Worst case)[Euro/year]		2.181.896.477,22 €	2.984.052.349,57 €	3.640.543.652,74 €	4.181.677.034,09 €	4.629.417.189,79 €
Difference in net present value [Euro/year]	- 11.004.708,00 €	- 15.583.556,57 €	- 11.221.968,36 €	- 1.590.895,59 €	15.061.217,89 €	37.546.291,51 €

Fig. 10-10 Total oil production [bbl] for different future scenarios

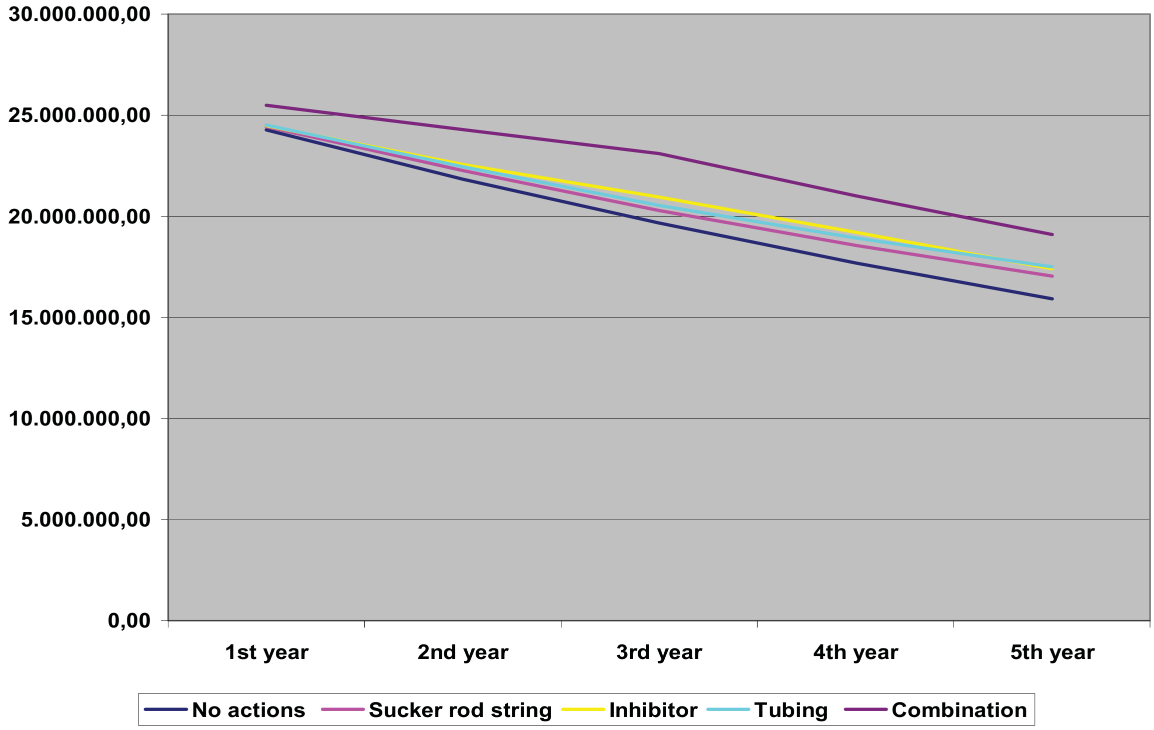


Fig. 10-11 Annual production increase [bbl] for different future scenarios

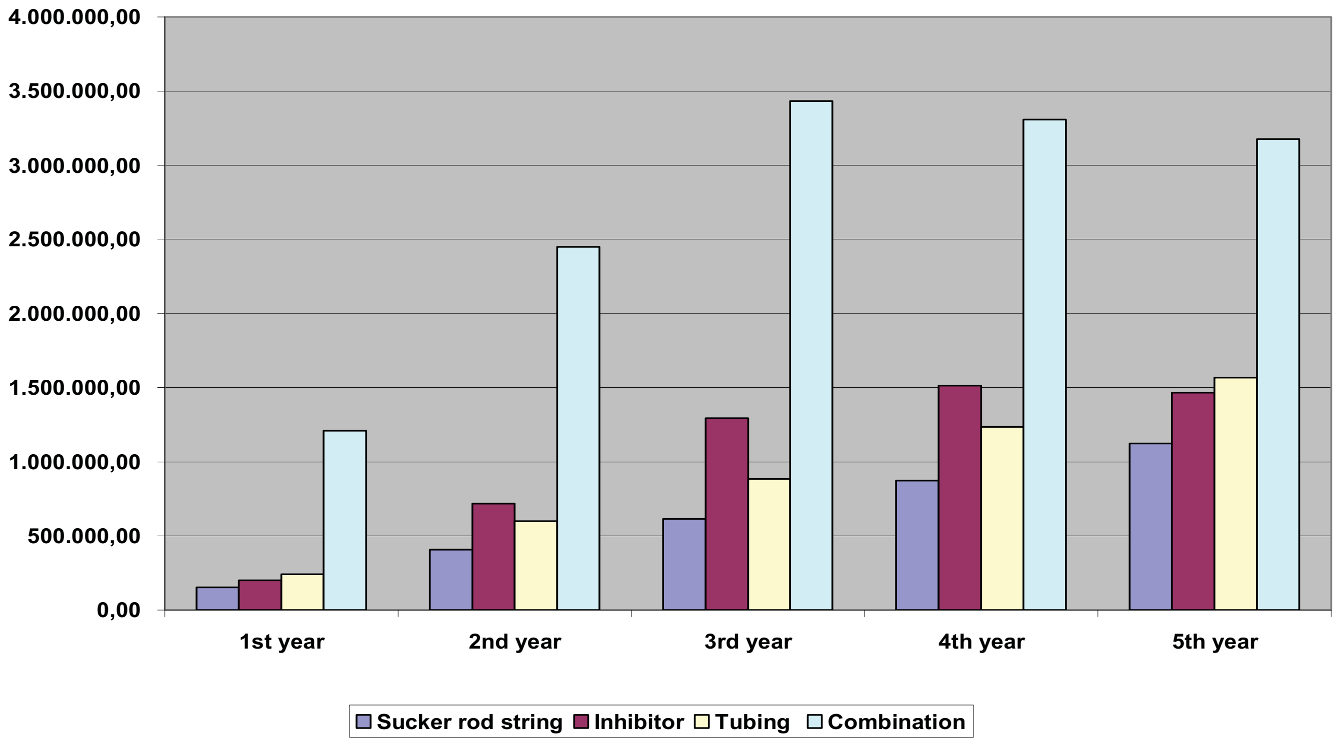


Fig. 10-12 Annual production increase in percent for different future scenarios