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FACULTY OF TECHNOLOGY
LUT ENERGY
ELECTRICAL ENGINEERING

MASTER'S THESIS

OPTIMIZATION OF WIND FARM INSTALLATIONS

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Abstract

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The aim of the diplomawork is a to obtain a method for optimization of wind farm installations. The algorithm based on the determination of the design alternative with the best economic characteristics by varying the number of wind mills, their locations and hub heights.

The efficiency of the station depends on the wind resources, the model of the turbine and the farm configuration. The Weibull probability density function of the wind speed, privilege wind direction, roughness class of terrain and soil conditions describe the model of the area, where a wind farm is planned to be constructed. One size and type of the wind turbine, its power curve and possible tower heights also are assumed as a basis for optimization. Criteria for the estimation of the project's benefit level are the Net Present Value, the Internal Rate of Return, the Cost of Energy and the payback period. The comparison of these economical performances gives an answer about which variants are preferable.

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Abbreviations and symbols

AEP	Annual Energy Production
COE	Cost of Energy
IRR	Internal rate of return
NPV	Net Present Value
O&M	Operation and Maintenance
VBA	Visual Basic Application
A	swept area
$A_{Overlap}$	swept area of rotor which is covered by expanded wake
c	scale parameters of the Weibull distribution function; price for electricity
C_{inv}	capital cost
C_{OM}	O&M cost
C_p	power coefficient
C_T	turbine trust coefficient
D	diameter of the wind turbine rotor blades
$f(V)$	probability density function
h	hub height
h_0	height on which the wind speed is measured
Δh	absolute difference between total heights of turbines
I	income
k	shape parameter of the Weibull distribution function
K	number of possible design alternatives
l	number of possible locations
M	number of wind directions
N	total number of installed turbines
p	wind frequency of the certain direction; interest (or discount) rate
$P(V)$	power curve of the wind turbine
P_{kin}	power of the wind flow

T	project life time
T_{op}	number of operational hours per year
T_{pb}	payback time
V	wind speed
V_0	undisturbed wind speed; measured wind speed
V_{in}	cut-in speed
V_{out}	cut-out speed
x	co-ordinate with respect to axis
X	distance at which wind speed is interested of
y	co-ordinate with respect to axis
z	co-ordinate with respect to axis
z_0	ground roughness length
z_L	distance between turbines scaled to the rotor diameter
 Greek	
α	wake decay constant; angle between main wind velocity direction and connection line between turbines
β	coefficient characterizing decline of wake effect depending on distance between turbines
ε	annuity
γ	wind gradient exponent
η	drive train efficiency
κ	discounting parameter
ρ	air density
w	wake effect

Subindexes

min	minimum
max	maximum

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1 Introduction

Resently the European Community set a target to increase both the security and the reliability of the power system operation and also to minimize its environmental impact. Furthermore the reserves of fossil resources (oil, gas and coal) are running out. Therefore as a logical consequence it is not surprising that European countries are trying to reduce or even eliminate their dependency on importing fuel. For that reason the interest in renewable energy technologies/ green energy has increased significantly.

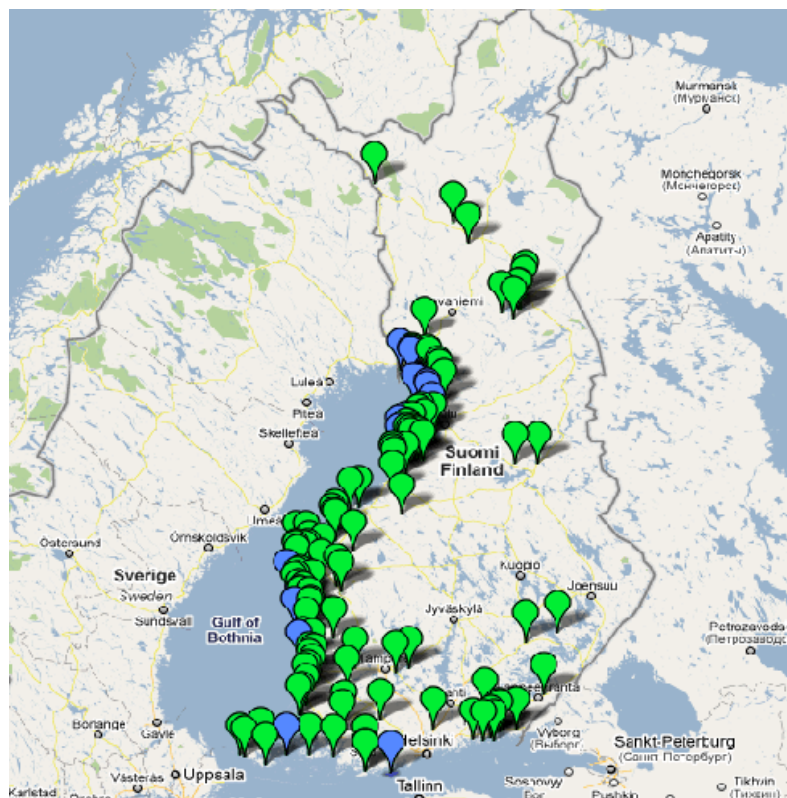


Fig. 1.1. Wind power projects in Finland [1].

Possible projects for wind power production in Finland according to data from January 2011 are marked on the map in Figure 1.1 [1]. The total capacity is 6000 MW, from them 3000 MW are offshore plants indicated with the blue colour [1]. Finland has the objective to install wind power capacities of 2.5 GW by 2020. To meet that goal the government enacted a legislation for feed-in tariff in December 2010 with guaranteed prices for wind energy for the period of 12

years [1]. At the moment various wind projects exist. Thus the question arises of choosing the most profitable alternative among the presented ones, as only limited can be supplied with government support.

Wind energy is one of the most popular alternative sources of energy production owed to fact that its production is clean, the source of power itself does not create costs and nowadays the whole system is economically comparable with conventional fossil fuel power production.

The working principle is simple. The wind turbine rotor takes out the kinetic energy from the wind flow by slowing it down while driving a generator, which converts mechanic to electrical power. A wind park (in other words wind farm) is a number of electrically and economically connected wind turbines installed in a same area (Figure 1.2 [2]). Wind farms are normally characterized with low marginal cost (zero fuel costs) together with solid investments. Reasonable design solutions play a crucial role in the cost-benefit aspects of the wind farm.



Fig. 1.2. Onshore wind farm in USA [2].

The main objective of this research is the optimization of number, locations and heights of wind units according to issue of net revenue maximization. The balance between expenditure and revenue from the trade of energy to network needs

to be found. The components affecting on the Net Present Value (NPV) function are analysed and an algorithm for solving the optimization problem is offered in this work.

This optimization is performed under the following terms:

- wind resource data is known;
- best possible locations for installation of wind mills with best conditions are proposed;
- the power curve of the wind turbine is provided by manufacturer.

2 Theoretical analysis of the object and subject of the thesis work

The capital cost of the wind farm depends on such factors as topography, soil conditions, type of the farm and infrastructure of the area. Wind farms are installed at the places where the source of energy has best parameters. In other words, the wind has a prevalent direction and a high frequency of the prevalent wind speed. They can be build either on land or at the see. At the moment the offshore projects are less popular as they are characterized with higher capital costs compared to onshore ones (roughly around 30-50% higher by the reason of cost intensive foundations, transportation and civil engineering works). At the same time the wind conditions usually are better in an open sea area. For the inland farms the roughness of terrain has a strong influence on the energy production of the turbines. Ground conditions also have a high effect on the cost parameters of the farm installations.

The main wind turbines components are depicted in Figure 2.1:

- rotor;
- nacelle;
- tower;
- foundation.

Various mechanical and electrical equipment such as gear box, generator, control system is located inside the nacelle, which is placed on the top of the turbine tower. The foundation supports the weight of the turbine and depends on the size of the wind turbine and soil conditions.

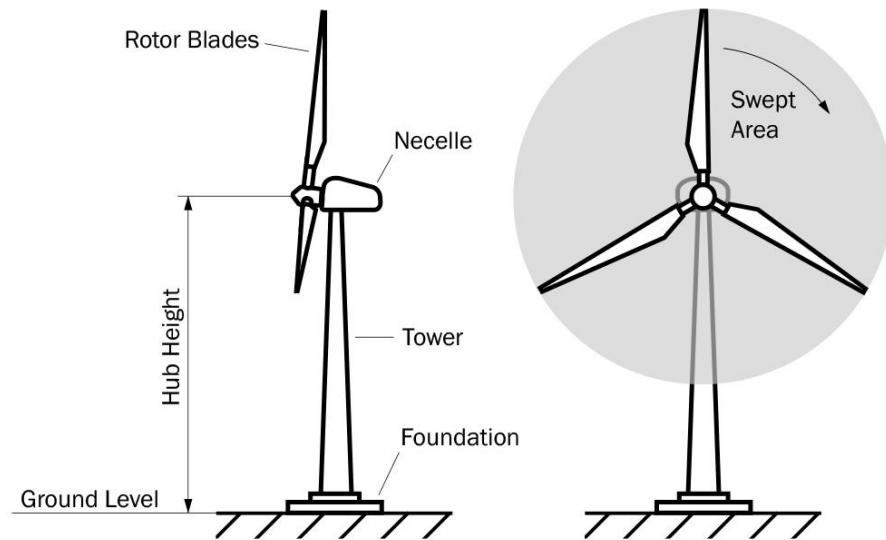


Fig. 2.1. Wind turbine structure.

Wind power plants can be connected to the distribution or transmission network depending on the size of the plant and network availability. Modern wind farms may consist of hundreds of wind turbines and generally they are connected to high voltage transmission system 110 kV or 220 kV to deliver produced power to the grid.

First of all the basic concept of wind power is given in the chapter below. The factors affecting the economics of a wind farm are described in the following section.

2.1 Wind energy basics

This chapter builds up a background for the study. The explanation of main definitions and basic concepts about wind energy are given in what follows.

2.1.1 Energy of the wind

Wind is intermittent, i.e. the wind speed and direction vary with time and, that is also important to mark, with height. Nevertheless, the statistic data, that has been collected over years of recording, gives a picture of wind conditions for a certain area. Special measurement equipment such as anemometers and wind vanes provide information about wind speed and wind direction, respectively. The resource assessment can be performed and displayed in a variety of ways.

A wind rose is an angular diagram which demonstrates the frequency and power of the wind in geographical azimuth coverage. The sum of the frequencies in all directions is equal 1.

A histogram shows the frequency occurrence of wind speeds. It is possible to obtain a mathematical function of the probability density $f(V)$ to characterize wind speed intervals. The most common function, which serves the purpose to analyse wind data is the so called Weibull probability density function[3]:

$$f(V) = \frac{k}{c} \left(\frac{V}{c}\right)^{k-1} e^{-\left(\frac{V}{c}\right)^k} \quad (2.1)$$

Where V is the wind speed, m/s; k , c are the shape and scale parameters of the function, respectively.

Examples of the wind rose and histogram of wind speed are shown in Figure 2.2 [4], [5].

The wind speed distribution is of great concern, due to fact that the kinetic energy, which is contained by the wind, depends on the cube of its speed [6]:

$$P_{kin} = \frac{1}{2} \rho A V^3 \quad (2.2)$$

Where ρ is the air density, kg/m^3 ; A is the swept area, m^2 ; V is the wind speed, m/s .

The normal value of the air density is considered to be 1.225 kg/m^3 [3].

$$A = \pi \cdot \frac{D^2}{4} \quad (2.3)$$

Where D is the diameter of the wind turbine rotor, m .

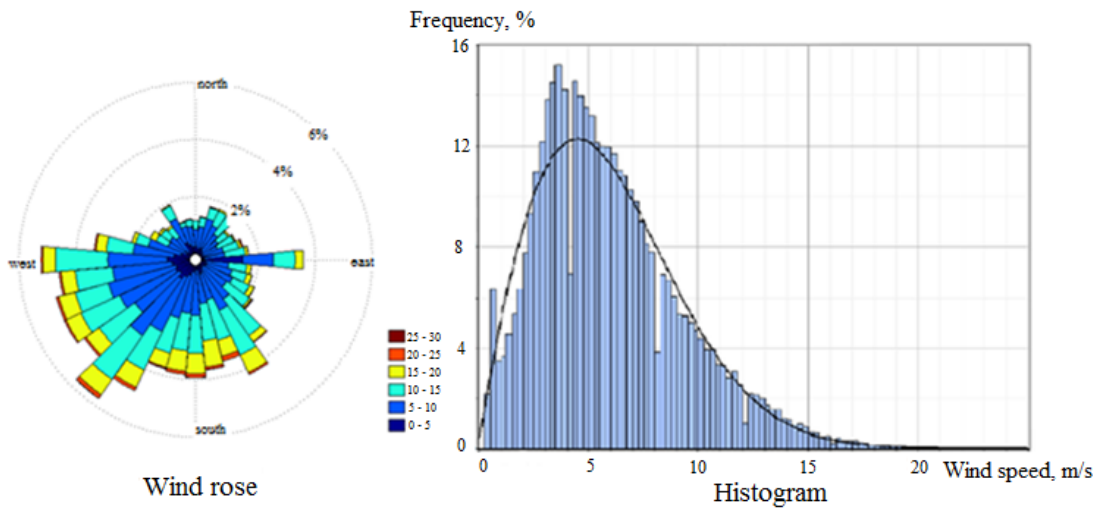


Fig. 2.2. Example of wind rose and histogram [4], [5].

The wind speed increases with height and is influenced by the roughness class of the terrain. An example of wind gradients is depicted in Figure 2.3 [7]. It can be estimated by using following simple equation, which gives the best result when the height is above 50 m [8]:

$$\frac{V}{V_0} = \left(\frac{h}{h_0} \right)^\gamma \quad (2.4)$$

Where V_0 is the measured wind speed on the height h_0 , m/s ; h is the hub height, m ; γ is the wind gradient exponent that shows the roughness of the terrain. It can be estimated using the following equation [9]:

$$\gamma = \frac{0.5}{\ln(h/z_0)} \quad (2.5)$$

With z_0 as the roughness length, m; h as the hub height, m.

The roughness length is defined via the terrain conditions. Typical values vary from 0.0001 m for flat ground to 4.0 m for cities with tall buildings [6].

The hub height is the distance from the foundation at the ground to the center line of the turbine rotor.

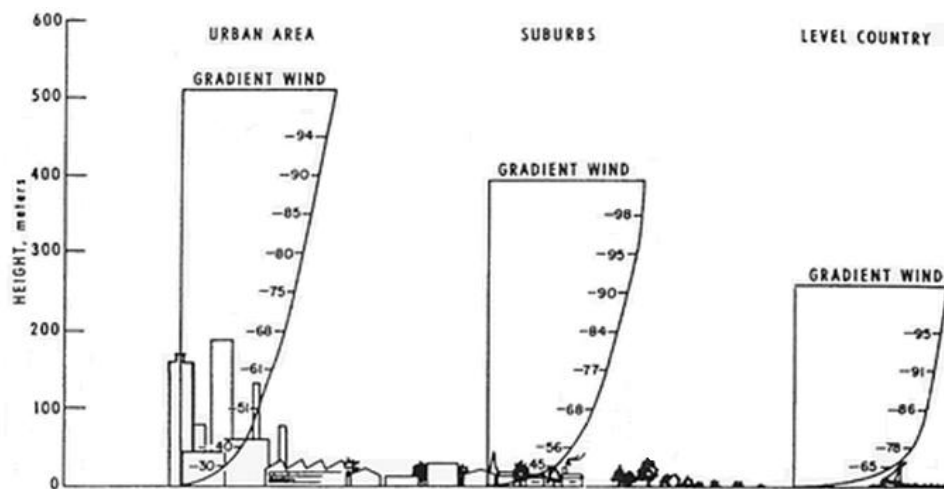


Fig. 2.3. Wind gradient.

Table 2.1 Typical values for roughness length, z_0 and wind gradient exponent, γ

Roughness class	Roughness length z_0 , m	Wind gradient exponent, γ
0 – open water	0.0002	0.1
1 – open plain	0.03	0.15
2 – countryside with farms	0.1	0.2
3 – villages and low forest	0.4	0.3

The choice of the right spot in the terrain is an issue of finding the place with the best conditions for a certain turbine. Thereby attention should be paid to the ter-

ritory, i.e. to its topology, soil conditions, the presence of various obstacles; to wind conditions, i.e. to wind speed and direction; also to such aspects as noise and aesthetics.

Usually wind mills are located on the top of hills, because in general the wind is stronger there. It is obvious that it is reduced significantly by obstacles like buildings or trees. Obstructions create a turbulent flow and as a result the speed of the airflow is decreasing. There is a simple rule how to estimate the dimensions of the turbulent area after the obstruction illustrated in Figure 2.4, leading to a reference for positioning turbines situated downwind of obstacles.

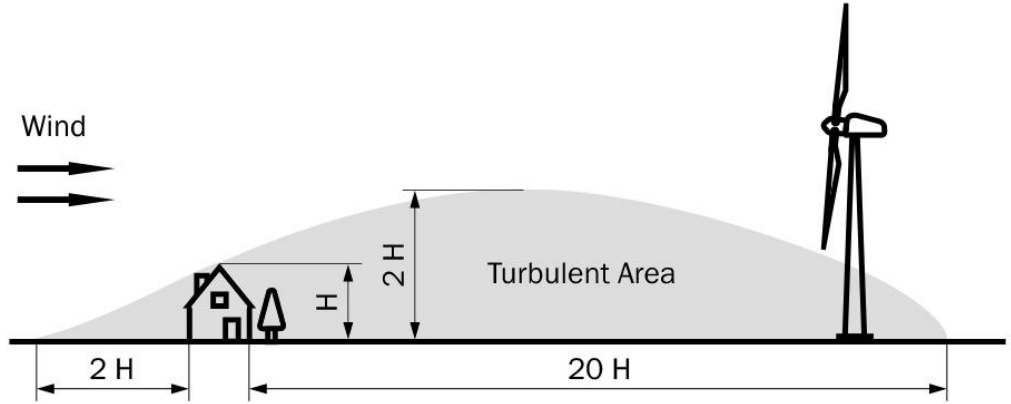


Fig. 2.4. Obstruction of the wind by obstacles of height H.

Also the turbine itself works as a barrier for the wind flow and reduces the wind velocity behind it. Therefore plants located in the direct downstream of other turbines are less productive. This interference of turbines is called wake effect, which is shown schematically in Figure 2.5 [10]. The downstream wind speed V_x of the turbine can be found using the following method [11]:

$$V_x = V_0 \left(1 - \frac{(1 - \sqrt{1 - C_T})}{\left(1 + 2\alpha \frac{X}{D}\right)^2} \right) \frac{A_{Overlap}}{A_i} \quad (2.6)$$

Where V_0 is the free wind speed before the turbine, m/s; C_T is the turbine thrust coefficient; α is the wake decay constant; X is the distance at which the wind speed is of interest, m; D is the diameter of the blades, m; $A_{Overlap}$ is the swept area of the rotor which is covered by expanded wake m^2 ; A_i is the swept area of the downstream turbine, m^2 .

The wake decay constant shows how the “shadow cone” increases in meters per meter behind the rotor. It means that the turbulent area created by the turbine broadens. The typical value for plants on land is 0.075 m [12], but in the case of a wind park, where several rows of turbines are installed, the opening angle of the wake cone increases if after a turbine which is already within the wake of another plant.

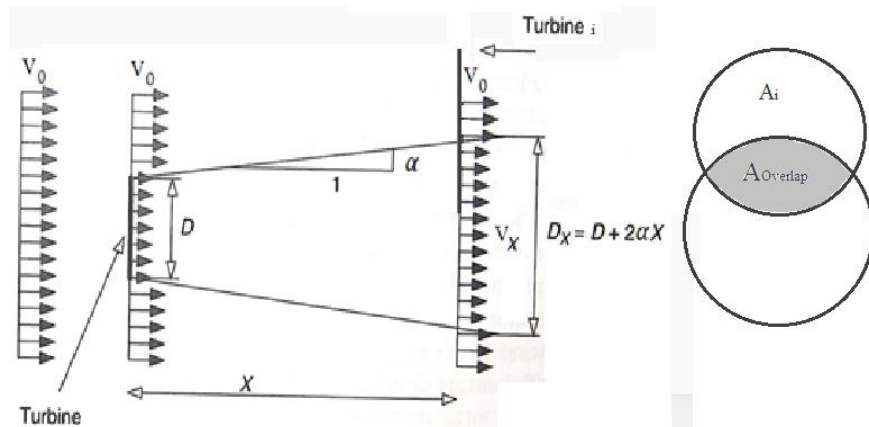


Fig. 2.5. Schematic view of wake effect.

The thrust coefficient is the relation of the thrust force (in other words the force with which the wind acts on the turbine) and dynamic pressure of the air flow multiplied by swept area. The value of C_T equals 8/9 in theory [10].

Array losses depend on a number of factors such as wind rose, type and size of turbines, their placement, turbulence intensity (TI). TI characterizes the level of turbulence in percentages. For example, for ideal flat area its value is 0%. Typical values are at around 10%. TI is determined as a relation of standard deviation

and mean wind velocity [10]. The wind deviation is a variation of wind speed during certain observation period.

The impact of several turbines on the energy output of a turbine in the downstream is the sum of the wake effects of each turbine found separately. In case of an interaction of several turbines, the velocity reduction can be calculated by [13]:

$$V_i = V_0 - \sqrt{\sum_{j=1}^{N_i} (V_j - V_{j,i})^2} \quad (2.7)$$

Where N_i is the number of j wind turbines influencing the i one; V_0 is the undisturbed wind speed, m/s; V_j is the wind speed at the turbine inlet, m/s; $V_{j,i}$ is the downstream wind speed of j turbine at the position of i turbine, m/s.

Experimental data shows that there should be a distance between turbines of at least several times of the length of the blades, to make sure that the loss of energy of the wind farm as a consequence of the wake effect stays within a low level. Array losses are within 10 percent with TI of 10% if the wind turbines placed at a distance of 8 to 10 rotor diameters in the direction of the prevailing wind and at the distance of 5 diameters of the turbine rotor across the prevailing wind direction [10].

2.1.2 Power curve of wind turbine

Electrical power produced by the wind turbine at a certain wind speed can be found by the following equation [10]:

$$P(V) = P_{kin} C_p \eta = \frac{1}{2} \rho A V^3 C_p \eta \quad (2.8)$$

Where P_{kin} is the power of the flow (Eq. 2.2); C_p is the power coefficient; η is the drive train efficiency.

The power coefficient is the ratio of actual power produced by a wind turbine to kinetic power of wind. According to Betz limit, the maximum energy which can be taken from the wind by a single rotor is 59.3% [10]. At the moment turbines with coefficient around 0.45 at the wind speed 8-10 m/s are in use. The drive train efficiency shows the mechanical and as well electrical efficiency of the turbine, i.e. it is the relationship of the power output of the generator compared to the rotor power. Its value can be taken as a constant equal to 0.9 [14].

The figure below shows the characteristic of the power output depending on the wind velocity for the turbine with a rated power of 3000 kW.

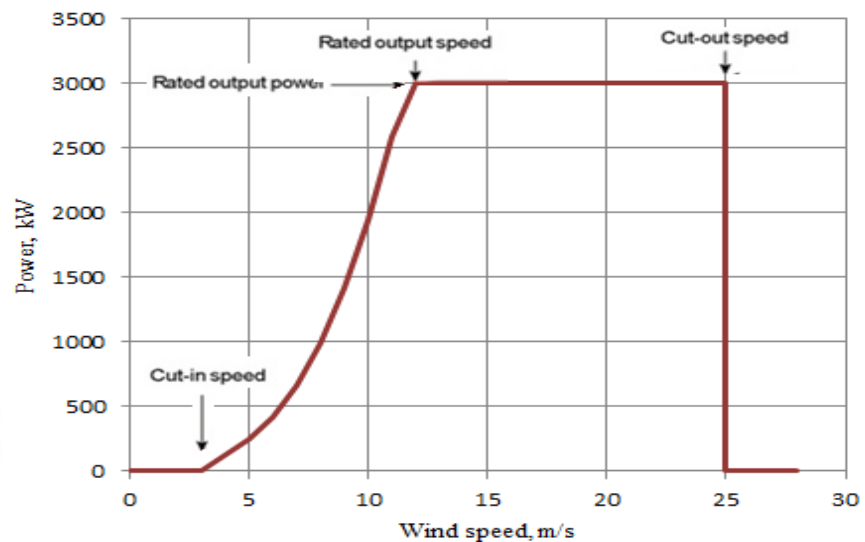


Fig. 2.6. Example of power curve of wind turbine [17].

The cut-in wind speed is the minimum wind speed for the start of the turbine rotation. The cut-out speed is the maximum speed when turbine has to stop due to the safety reasons. The rated output power is the maximum output of the turbine. The wind speed at which it is reached is called rated output wind speed.

2.1.3 Annual energy production of the wind turbine

The wind park annual energy production (AEP) can be determined by the wind turbine power curve and the wind speed frequency distribution on the hub heights of the turbines [10]:

$$AEP = T_{op} \sum_{k=1}^M \left(p_k \sum_{i=1}^N \int_{V_{in}}^{V_{out}} P_i(V) f_{i,k}(V) dV \right) \quad (2.9)$$

Where T_{op} is the number of operational hours per year; p_k is the wind frequency of the k direction; $P_i(V)$ is the power curve of the i wind turbine; $f_{i,k}(V)$ is the probability density function of the i wind turbine in the k wind direction; V_{in} is the cut-in speed; V_{out} is the cut-out speed; M is the number of wind directions ; N is the total number of turbines of the wind farm.

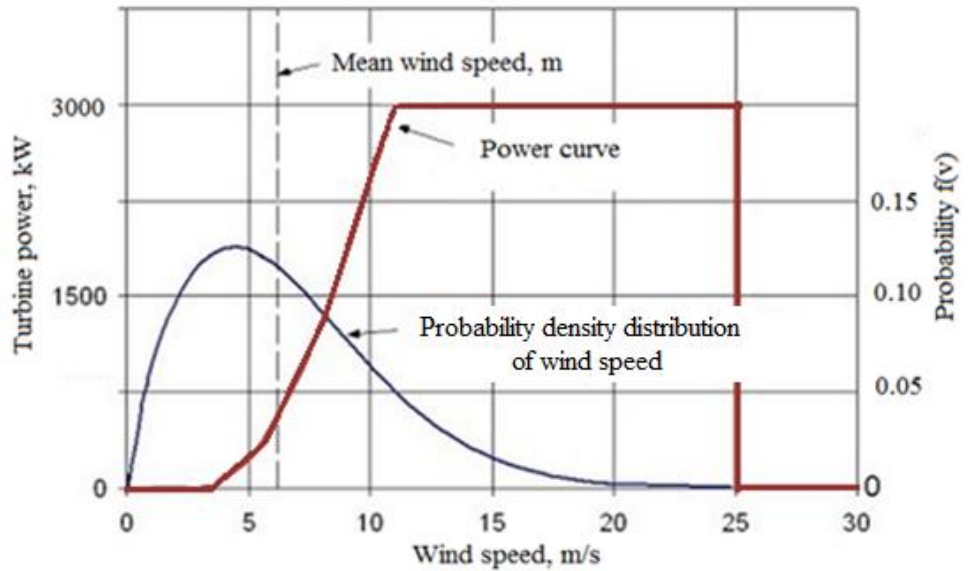


Fig. 2.7. Calculation of the AEP [17].

The wind speed has a crucial role on the value of the total park AEP, due to the dependence of the power curve on wind velocity in the third power (Eq. 2.8). In consequence of wake losses, the power production of the downstream turbines decreases. With a few rows of turbines located in front of the turbine under ex-

amination, its production output is reduced, due to cumulative wake of the upstream turbines. It means that revenues obtained by individual turbines of the wind park are not equal and AEP needs to be analyzed separately for each turbine planned to be installed. The wake effect eventually can be taken as a percentage of which the AEP for certain turbine is reduced.

$$w_i = \sum_{j=1}^{N_i} w_{ij} \quad (2.10)$$

Where N_i is the number of j wind turbine influencing on the i one; w_i is the wake effect on the turbine under study; w_{ij} is the wake effect of the j upstream turbine on the i turbine under consideration.

In such a manner the equation for calculation of the AEP is taking the following form which considers all wake losses:

$$AEP = T_{op} \sum_{k=1}^M \left(p_k \sum_{i=1}^N \int_{V_{in}}^{V_{out}} P_i(V)(1 - w_i) f_{i,k}(V) dV \right) \quad (2.11)$$

Such parameters as hub height influence the energy production of the wind turbine, according to the wind speed, which is increasing with height. This gradient depends on the roughness class of the terrain (Eq. 2.4). In the sea and open flat area the wind velocity is not rising with the height as significantly compared to rural areas with low forests (Figure 2.8). The main disadvantage of higher plants is the expenditures for turbines with a taller tower are higher. The final design choice is based on economic reasons.

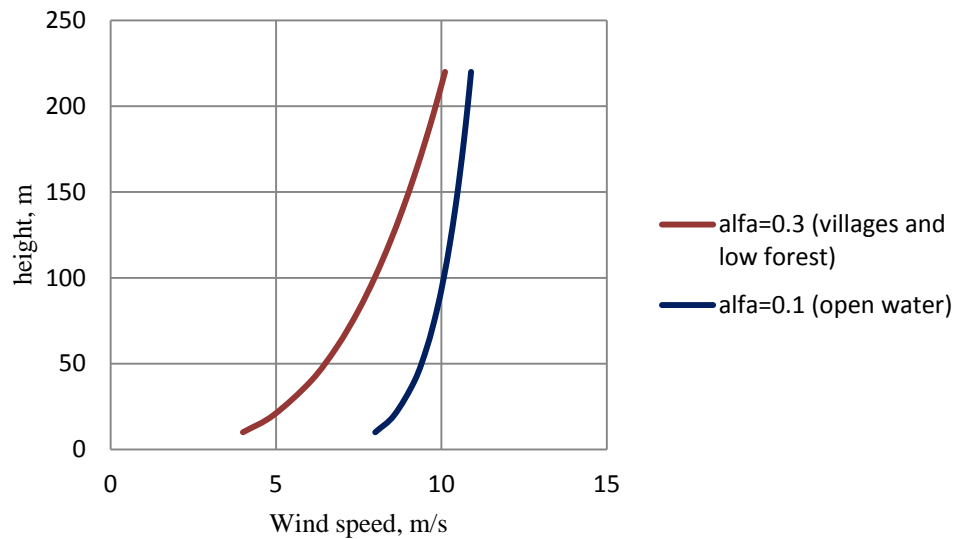


Fig. 2.8. Comparison of wind speed gradients for different terrains classes.

2.2 Wind farm economics

The economics of wind energy consist of the following main components:

- Initial investments;
- Operation and maintenance costs;
- Income.

Investments are the lump-sum costs. For economic analysis it is necessary to compare them with annual operation and maintenance (O&M) costs and annual income. One of the two main principles – the present value method and annuity calculations could be chosen for that comparison.

Such parameters as lifetime of the project (roughly 20 years) and discount factors play a crucial role in the project decision making.

In this work, the economic result for the different options of wind farm design are analyzed by calculations of the net present value (NPV), internal rate of return (IRR), payback period and cost of energy (COE) production for each one.

NPV is the sum of the discounted cash flow during the life time of the system, that means that all future revenues and expenditures should be given to present time by using the discount factor [3]:

$$\kappa_t = \frac{1}{\alpha^t} = \frac{1}{\left(1 + \frac{p}{100}\right)^t} \quad (2.12)$$

Where p is the interest (or discount) rate, i.e. the percentage of money that needs to be paid annually for a loan at the year t .

2.2.1 Investments costs.

The capital cost of the project includes the cost for design work, purchase of equipment, rent of land for onshore projects, civil works, electrical infrastructure costs, etc. At the stage of option comparison usually a simplification is done and therefore some cost parameters are ignored.

Investment costs in a wind farm are the sum of the costs for each i turbine unit:

$$C_{inv} = \sum_{i=1}^N (WT_i(\text{type}, P, H) + F_i(\text{type}, \text{soil}) + C_i(A, \text{soil})L_{ci} + \\ + R_i(\text{type}, \text{soil})L_{Ri}) + S(P) \quad (2.13)$$

Where N is the total number of installed turbines. The other variables in the formula mean capital cost for the next wind farm components: WT_i – wind turbine, € (type – the model (manufacturer, three-bladed upwind rotor, direct-drive, etc.) of turbine); F – foundation, €; C_i – local distribution network (cables), €/m; R_i – roads, €/m; S – cost of the substation, €. L_{Ri} , L_{ci} are the lengths of the road and connection cables for i turbine, respectively, m.

Explanations to the main factors which influence the prices for different components of the project are given below.

The wind turbine plays the major role in total investment cost (around 70 % [10]). Expenses vary in relation to type and size, i.e. rated power capacity P of turbine. Larger blades can capture more wind and, as mentioned above, the tower height H plays an essential role in the power output of the turbine, as they provide access better wind conditions. But if the size of swept area and hub height are increased, also the costs of the turbine rises.

The foundation carries the static weight of the turbine and leads the forces of the wind into the ground, therefore these expenses depend on the type of turbine, the hub height and soil condition.

In most cases wind farms are located in rural areas, where access to the network is a technical issue. It can require constructions or upgrades of the existent transmission system. Substations need to be constructed to connect the wind farm to the grid. Rated power, voltage and as consequence price of substation transformer vary with the rated power output of the park, in other words the maximum total capacity of the turbines.

Each turbine is connected to the network via a cable which runs out to the substation. These expenditures vary depending on the intersection A (mm^2) of the cable, which is selected according to rated power output of the turbine, voltage of the local distribution network within the wind farm and the distance of the field cable installation. The type of the soil has a significant effect on the prices for cable ploughing.

Likewise roads should be built to provide access to the wind turbines. This cost depends on the ground condition of the site and the length of the roads.

Typical relations between expenditures for different capital cost components are given in the Table 2.2 [10] below.

Table 2.2 Wind farm cost structure

Component	Percentage of total cost
Wind turbine	68 to 84
Foundation	1 to 9
Grid connection (cable + substation)	2 to 10
Road construction	1 to 5

2.2.2 O&M costs

As any other equipment a wind turbine requires attendance during its life time. Costs for operation and maintenance (O&M) depend on the types and size of the turbines. It is an expenditure for services, repairs, spare parts, insurance, losses, outages, telephone, taxes, fees, administration, etc. As this cost is periodic they need to be take into account in the present value for comparison with investment costs.

$$C_{OM} = \sum_{i,t=0}^{N,T} \kappa_t \cdot C_{OM,it} \quad (2.14)$$

Where N is the total number of installed turbines; T is the life time of the project; κ_t is the discounting parameter; $C_{OM,it}$ is the O&M cost for i turbine in t year.

More precise O&M cost assessment is very difficult, given that at this project stage of planning many parameters are quite rough. Usually it is taken as a percentage of the investment costs, which is growing during the life time of the project, as expenses are increasing due to aging of the equipment [15].

2.2.3 Income

The income depends on the power which is produced by the turbines of wind farm per year. The power produced by the turbine depends on the type and size of the turbine, wind resource and operational time. As well it is put to the present moment to analyze cost-effectiveness of the project.

$$I = \sum_{i,t=0}^{N,T} c_t \cdot \kappa_t \cdot AEP_{it} \quad (2.15)$$

Where N is the number of turbines; T is the project life time; c_t is the price for power, €/MWh; AEP_{it} is the power produced by turbine, MW; κ_t is the discounting parameter.

To assess the revenue received from energy selling the energy price per MWh within life time of the project is estimated. In different countries the government tries to supports wind energy and here Finland is not an exception. A feed-in tariff guaranties the level of the price for the wind energy.

2.3 Economic analysis

By comparison of net present values (NPV), internal rates of return (IRR), costs of the produced energy and pay-back times of different variants of wind park design it is possible to choose the most profitable ones. Each method of variants assessment has advantages and drawbacks.

2.3.1 Net present value

The Net present value is a discounted cash flow , i.e. the difference between revenues and expenditures of the project during the life time of the project, which is leading to present moment. NPV shows the benefit which investor will get from the project implementation.

$$NPV = \int_0^T (I - C_{inv} - C_{OM}) dt = \sum_{i,t=0}^{N,T} c_t \cdot \kappa_t \cdot AEP_{it} -$$

$$- \left[\sum_{i=1}^N (WT_i(type, P, H) + F_i(type, soil) + C_i(A, soil)L_{ci} + \right.$$

$$+R_i(\text{type, soil})L_{Ri} + S(P)] - \sum_{i,t=0}^{N,T} \kappa_t \cdot C_{OM,it} \quad (2.16)$$

The objective to obtain maximum NPV, in other words means to maximize the income and minimize capital outlay. The parameters that affect the value of the NPV are interdependent. For example, with increased height of the tower the turbine energy output increases by the aforesaid reason of wind speed elevation with height, as the power production of the turbine depends on the wind velocity in cube. But at the same time expenses are higher (the cost of the tower, foundation and civil costs).

One of the main assets of the NPV method is, that its result gives a clear picture to a potential investor about the yields of laid-down capital. It has respect to the time dependence of money using the discount factor and it also takes into account its variability. But it has a number of shortcomings. One of the biggest is that it doesn't provide the risks assessment of the project realization. It is hard to estimate and compare projects with different volumes of investment. Moreover the result of NPV is sensitive to the discount factor. A rough forecast of the interest rate value can lead to an erroneous result and the project which seemed profitable may become loss-making.

2.3.2 *Internal rate of return*

To estimate the expected level of investment yield the internal rate of return (IRR) is calculated. The IRR is a discount factor when NPV equals zero, in other words when the discounted revenues from the project are equal to discounted investment costs (Figure 2.9).

The higher the IRR becomes the more desirable for the owner it is to invest in the project. Its value is approximated by using the following equation which can be solved iteratively:

$$\sum_{t=0}^T \frac{C_{inv,t} + C_{OM,t}}{\left(1 + \frac{IRR}{100}\right)^t} - \sum_{t=0}^T \frac{I_t}{\left(1 + \frac{IRR}{100}\right)^t} = 0 \quad (2.17)$$

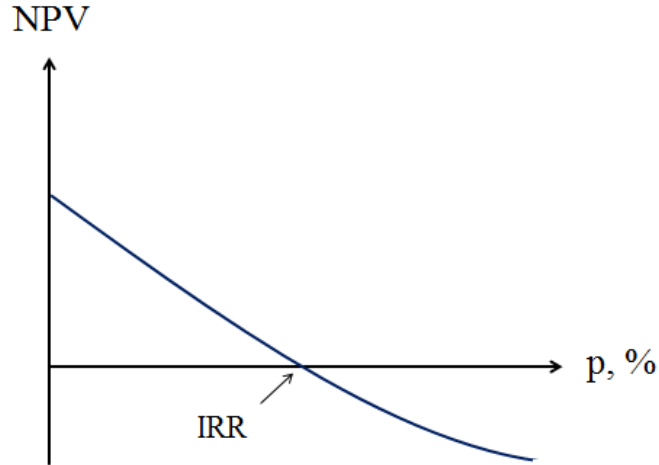


Fig. 2.9 Change of NPV in relation to p

This method shows the maximum discount rate for investing without money waste for the stakeholder. Just as the NPV it takes into account the time dependence of money, but it doesn't rely upon the interest rate. This method gives an opportunity to compare different sized projects. Notwithstanding IRR contains limitations. It doesn't give information about the monetary value of the profit. In the case when the discounted cash flow is changing between positive and negative several times during the life time the calculation can give values of the IRR that may cause erroneous conclusions.

2.3.3 Cost of energy

The cost of energy is a relation of total expenditures during the life time to the energy produced from the wind plant [10]:

$$COE = \frac{C_{inv} \cdot \varepsilon + C_{OM}}{AEP}, \text{ €/MWh} \quad (2.18)$$

Where ε is the annuity; AEP is the annual energy production, T is the investment life time.

The annuity is used for dividing capital one time costs into annual costs that required to be paid during life time of the project. It is calculated with the equation (2.20) [16]:

$$\varepsilon = \frac{p/100}{1 - \frac{1}{(1 + p/100)^T}} \quad (2.20)$$

Where p is the discount rate; T is the life time of the project.

This economic parameter demonstrates the amount of money, which needs to be spend by the stakeholder to produce 1 MWh of the electricity energy. It is easy to compare different alternatives by that method and the calculations of COE are simple. But COE ignores time value of money that can lead to wrong conclusions in conditions of precarious economic situation.

2.3.4 Pay-back period

The pay-back period shows time required to return investments and start to earn money from the project. It doesn't take into account time value of money and doesn't measure profitability of the project. But still it can be interesting for the investor, because it shows the investment conditions. The pay-back time can be calculated by following simple equation [15]:

$$T_{pb} = \frac{\textit{Total investment}}{\textit{Average annual energy income}} \quad (2.21)$$

2.3.5 Comparison of different economical methods

The situation when NPV and IRR methods give different answers which alternative is worth to be chosen is not an exception. Quite often the reason is the dif-

ference of the sizes of the investment projects. Each case should be analyzed individually. For example in the circumstances when one of the two variants has higher NPV and lower IRR when compared to another, in most cases the first one is chosen, as its benefit of the stakeholder is higher. But if the value of IRR is very significant the decision can differ.

The cost of energy and pay-back time are another two parameters which give a picture of the economic issue of the project. The lower value of COE and pay-back time are the more profitable the project is.

These four parameters are significant when the various options are compared, as well as they provide information about whether to invest in the project or not.

3 Statement of optimization problem and algorithm

3.1 Optimization problem analysis.

Designing a wind farm is a complex process consisting of a number of steps. From the start, wind resources of the area, where turbines are planned to be installed are studied. Experts supply information about possible spots with best wind conditions. After that, the comparative valuation of different placement schemes is progressed. The optimization of the wind farm installations is a key issue in the planning of the project. Among all possible variants the most investment beneficial are settled.

The most essential factors influencing the profitability of a project which are important in the stage of variants comparison are:

- Number of wind turbines planned to be install;
- Siting of turbines on the certain area;
- Type and size of the wind engine;
- Hub height.

The number of possible design alternatives K need to be reviewed for n turbines:

$$K_n = \frac{l!}{(l-n)!n!} h^n t^n \quad (3.1)$$

Where l is the number of possible locations; n is the number of projected turbines; h is the number of hub height alternatives; t is the number of the turbines with different rate capacity.

A simple example of a calculation K is demonstrated below. It is assumed there are three possible locations, two models of the turbine with two optional tower heights each. The total amount of variants is next:

$$n = 1: K_1 = \frac{3!}{(3-1)!1!} 2^1 2^1 = 12$$

$$n = 2: K_2 = \frac{3!}{(3-2)!2!} 2^2 2^2 = 48$$

$$n = 3: K_3 = \frac{3!}{(3-3)!3!} 2^3 2^3 = 64$$

The total number of variants under comparison $12+48+64=124$.

Depending on the number of variables K increases significantly. Therefore a tool for solving the optimization problem is required.

An analysis is performed by the comparison of net present value (NPV) and internal rate of return (IRR) of feasible alternatives. Such economic parameters as cost of energy (COE) and pay-back time (T_{pb}) are under consideration as well.

The construction of the wind farm has a significant effect on the economic parameters, due to interrelatedness of variables. Spacing between turbine has an influence on the AEP, due to the wake effect, which is a cause of energy losses. Also the hub height has an effect on the output of turbines and capital costs. The

aim is to get a version of wind farm configuration with maximum energy production and less expenditures.

3.2 Optimization algorithm

The algorithm serves to solve the wind farm optimization problem. For different variants economic parameters are calculated. The answer, which is the most beneficial from different points of view, is given as a result of computation.

Wind and soil conditions, type of turbine with possible heights of the tower and costs for equipment purchasing and operation and maintenance serve as an insertion data. Each location is characterized with x, y and z coordinates and contains information about the spots on the certain area.

The algorithm is working with locations and hub heights and one type of turbine is used in this optimization. The roughness class of terrain is given, in other words the wind gradient is the same for the whole area which is under consideration. The power curve of the certain turbine model assumed to be provided by the manufacturer. As well the privilege wind direction and probability density distribution of wind speed on different hub heights are treated to be known. Every possible variant of design is codified with numbers for its computation.

The algorithm is presented below in the form of block schematic diagram (Figure 3.1).

On the first step of solving the optimization problem, the location data and the performance characteristic of the wind farm are estimated. The capital costs depend on type and size of the turbine, hub height and ground conditions. In the next step the results for all possible wind park configuration are calculated. Therefore the number of turbines, their tower height and location are being varied repeatedly until every single possible solution has been calculated.

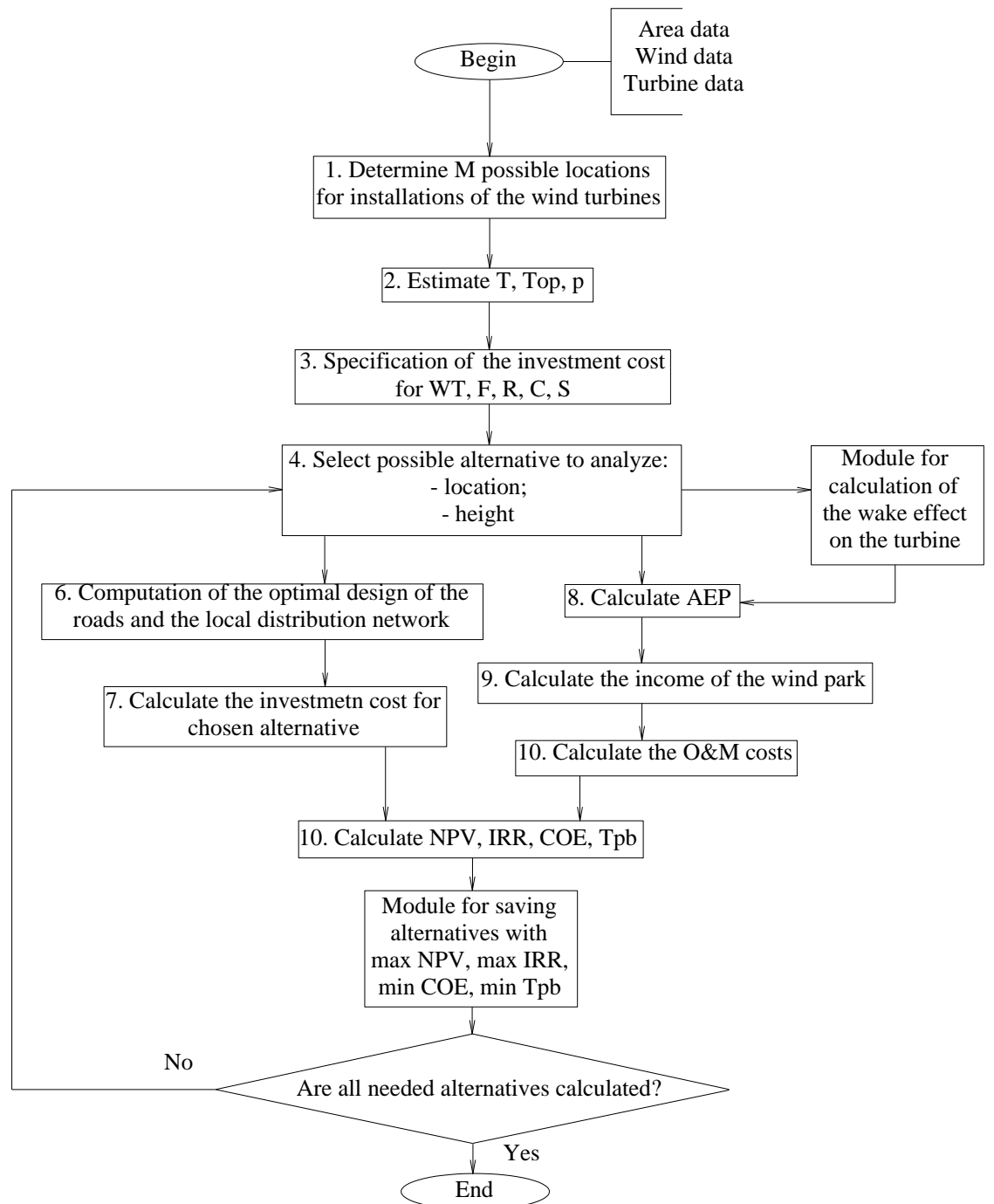


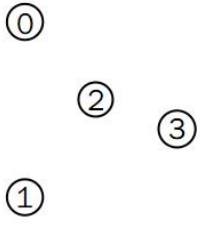
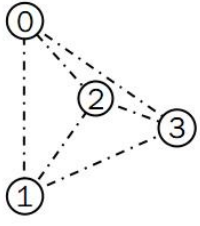
Fig. 3.1. Flow diagram of the optimization algorithm

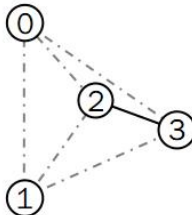
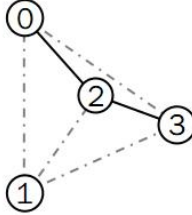
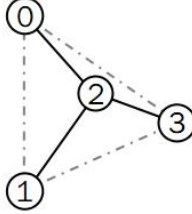
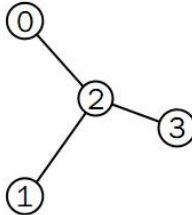
For each solution that is calculated, the roads and local distribution lines should be built separately in the optimal way. The construction of roads and cable placing require complete data about topology and ground properties on their own as well. Therefore it is an individual task for each combination how to construct

them with minimal expenditures. Due to lack of exact data, the roads are assumed to be built and cables are assumed to be installed in the ground on straight lines between turbine placements. The costs of the roads and laying of cable per meter are depending on the soil conditions, as mentioned above. To take that into account, the calculation of average cost index of the area spanned between the two connecting points is being done. The roads only make from 1 to 5% of the total capital costs of the wind farm. The grid connection contributes to the overall costs from 2 to 10 % whereas most of it is the costs for the substation (Table 2.2). On the stage of variant comparison, with limited amount of reliable data, the calculation method is a convenient choice for this application, because it doesn't bring serious harm to the end result. Also the calculation needs to be done separately for each solution, therefore the assumption of straight connections and the described method to calculate their costs promote the overall processing time of the program.

The method for calculating the minimal distances between turbines is presented below step by step in the form of the table.

Table 3.1 Method to calculate distanses

	0	1	2	3		Calculate distances from each turbine to all others.
0	0	7.94	4.78	8.69		
1	7.94	0	5.83	7.82		
2	4.78	5.83	0	4.02		
3	8.69	7.82	4.02	0		
	0	1	2	3		Compare all distances and find the shortest.
0	0	7.94	4.78	8.69		
1	7.94	0	5.83	7.82		
2	4.78	5.83	0	4.02		
3	8.69	7.82	4.02	0		

	0	1	2	3		Connect the two turbines with the shortest link. Columns of already connected turbines will not be considered.																									
<table border="1" data-bbox="375 257 758 504"> <thead> <tr><th></th><th>0</th><th>1</th><th>2</th><th>3</th></tr> </thead> <tbody> <tr><th>0</th><td>0</td><td>7.94</td><td>4.78</td><td>8.69</td></tr> <tr><th>1</th><td>7.94</td><td>0</td><td>5.83</td><td>7.82</td></tr> <tr><th>2</th><td>4.78</td><td>5.83</td><td>0</td><td>4.02</td></tr> <tr><th>3</th><td>8.69</td><td>7.82</td><td>4.02</td><td>0</td></tr> </tbody> </table>		0	1	2	3	0	0	7.94	4.78	8.69	1	7.94	0	5.83	7.82	2	4.78	5.83	0	4.02	3	8.69	7.82	4.02	0						Columns of already connected turbines will be not be taken into account. Among the remaining cells, the shortest connection will be used.
	0	1	2	3																											
0	0	7.94	4.78	8.69																											
1	7.94	0	5.83	7.82																											
2	4.78	5.83	0	4.02																											
3	8.69	7.82	4.02	0																											
<table border="1" data-bbox="375 593 758 840"> <thead> <tr><th></th><th>0</th><th>1</th><th>2</th><th>3</th></tr> </thead> <tbody> <tr><th>0</th><td>0</td><td>7.94</td><td>4.78</td><td>8.69</td></tr> <tr><th>1</th><td>7.94</td><td>0</td><td>5.83</td><td>7.82</td></tr> <tr><th>2</th><td>4.78</td><td>5.83</td><td>0</td><td>4.02</td></tr> <tr><th>3</th><td>8.69</td><td>7.82</td><td>4.02</td><td>0</td></tr> </tbody> </table>		0	1	2	3	0	0	7.94	4.78	8.69	1	7.94	0	5.83	7.82	2	4.78	5.83	0	4.02	3	8.69	7.82	4.02	0						This procedure is repeated until all stations are linked to the net.
	0	1	2	3																											
0	0	7.94	4.78	8.69																											
1	7.94	0	5.83	7.82																											
2	4.78	5.83	0	4.02																											
3	8.69	7.82	4.02	0																											
<table border="1" data-bbox="375 918 758 1164"> <thead> <tr><th></th><th>0</th><th>1</th><th>2</th><th>3</th></tr> </thead> <tbody> <tr><th>0</th><td>0</td><td>7.94</td><td>4.78</td><td>8.69</td></tr> <tr><th>1</th><td>7.94</td><td>0</td><td>5.83</td><td>7.82</td></tr> <tr><th>2</th><td>4.78</td><td>5.83</td><td>0</td><td>4.02</td></tr> <tr><th>3</th><td>8.69</td><td>7.82</td><td>4.02</td><td>0</td></tr> </tbody> </table>		0	1	2	3	0	0	7.94	4.78	8.69	1	7.94	0	5.83	7.82	2	4.78	5.83	0	4.02	3	8.69	7.82	4.02	0						Now each station is connected.
	0	1	2	3																											
0	0	7.94	4.78	8.69																											
1	7.94	0	5.83	7.82																											
2	4.78	5.83	0	4.02																											
3	8.69	7.82	4.02	0																											

After all investment costs are calculated for the wind park, next the annual energy production (AEP) is an important characteristic of which the value is determined. Wind distribution has a crucial role on the output of turbine due to relation of AEP from the wind speed in the third power (Eq. (2.8), (2.9)). Turbines create wake behind themselves, by this means that the wind speed is reduced. Therefore the power output of the turbines sited behind goes down. The number of turbines that experienced wake depending on the wake decay constant (Figure 2.5). To calculate wake effects which each turbine of the wind farm experiences is a complicated task by itself, because it is a function of the factors that are hard

to estimate, like for example weather conditions. The wake effect from several turbines are summarized. Each location is characterized with different heights. It is also taken into account by changing AEP with heights of the spot where it is sitting. This relation is assumed to be linear.

The next step is a calculation of wind farm income. Then O&M costs are found. They are assumed to be a value that is charged from the income. Economical parameters are calculated after the estimation of expenditures and revenues. The cycle repeats again.

An analysis of different alternatives is made by comparison of NPV, IRR, COE and T_{pb} . The variants with maximum NPV and IRR and minimum COE and T_{pb} are presented as a result.

The method for the optimization of wind farm installations is exercised on the example of a certain limited area. The numbers of possible locations, type and tower heights are assumed in optimization. The tool is developed in Microsoft Excel with programming of a Macro in Visual Basic for Applications (VBA) language.

3.3 Application of the tool

To perform the aforementioned optimization method for wind farm installations specific example is considered by Excel tool. In this chapter the description of the tool is given more precisely. The program code of the Macro's cycle is given in the Appendix.

3.3.1 Optimal design of roads and cable laying

The program cycle operates in the following way reported below. All possible design variants are put in a table sized (KxL) on the main sheet of the excel file, where K is a number of the wind farm design alternatives and L is a number of possible positions for plants on the map. Each variant is written in the string. At first, empty cells of each line are selected and stored, i.e. where the value equal

zero (turbine is not installed). All distances between possible locations are calculated on the main sheet of the file by:

$$z_L = \sqrt{(x_i - x_{i-1})^2 + (y_i - y_{i-1})^2} \quad (3.2)$$

Where $(x_i - x_{i-1})$ and $(y_i - y_{i-1})$ is the difference between coordinates of spots by axis of abscises and ordinates, respectively.

They are presented in the form of a table sized (LxL). It contains the information of distance between each possible plant location to every other plant. Later, the Macro refers to these cells, which contain information of the length. As described above firstly the minimum way is determined. Therewith a cycle, working with a condition which excludes double connections and ends the cycle after all turbines existing in the particular configuration are linked.

3.3.2 *Costs of roads and cable laying calculation*

Depending on the number of empty cells, i.e. number of spots where no turbines are sited, the costs for roads and cable installation are computed. The base price is multiplied by a cost coefficient and the length of the particular distance between turbines. The table of the cost coefficients is also written on the sheet of the excel file. The way which explains how they can be found is given above. Eventually the total costs value is the sum of every single connection cost.

3.3.3 *Determination of turbine and its foundation costs*

The turbine expenses are figured out according to the turbines' height. Whereas the costs of the foundation is in addition working with the condition of the particular soil type.

3.3.4 *Wake model*

To calculate the total AEP of the wind park with reasonable precision, wake losses should be estimated. The theoretical basis of the interferences between

turbines which are the reason of the farm power output reduction is described in the previous chapter (Section 2.1.3, Eq. (2.6)).

One size and type of turbine is considered in the case study, therefore the thrust coefficient is constant for each turbine of the farm. The estimation of the array losses is organized with distances between turbine placements, absolute difference of turbine heights and angle between the privilege wind direction and straight which links the stations. The modulation of the wake losses are organized in the following way, depicted in Figure 3.2. On Figure 3.3 the more detailed explanation of variables is demonstrated.

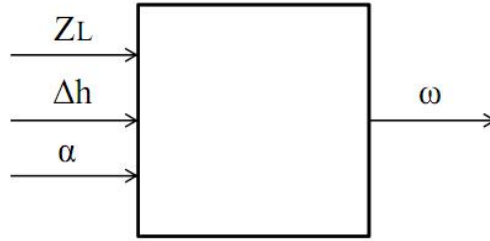


Fig. 3.2 Wake affect module

Array losses are computed in the Excel tool by following Eq. 3.3. The results is given in the form of a table sized (LxL) in percentages which demonstrate the value of power output reduction due to wake influence of upstream turbines.

$$w = \frac{1}{1 + z_L^\beta} \frac{1}{e^{\frac{\Delta h}{D}}} \cos \alpha = \frac{1}{1 + z_L^\beta} \frac{1}{e^{\frac{\Delta h}{D}}} \frac{z_L}{x} \quad (3.3)$$

Where z_L is the distance between turbines equated to the rotor diameter; β is a coefficient characterizing the decline of wake effect depending on Z_L (in the modulation it assumed 1.2); α is the angle between main wind velocity direction and conceptional line between turbines siting; Δh is the absolute magnitude difference between total heights of turbines; D is the diameter of rotor; x is the distance between turbines by abscise.

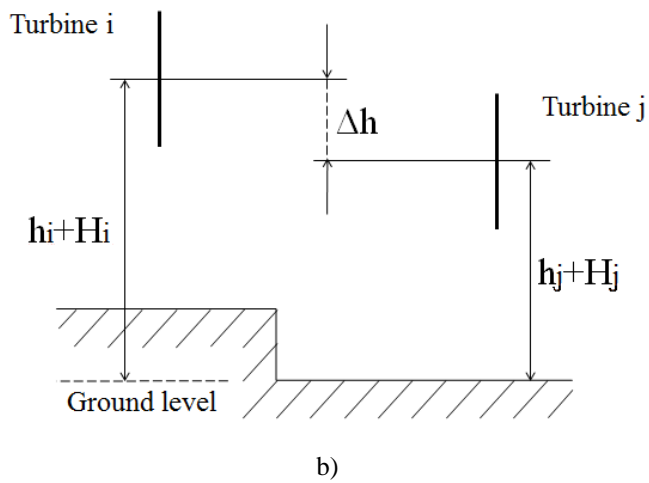
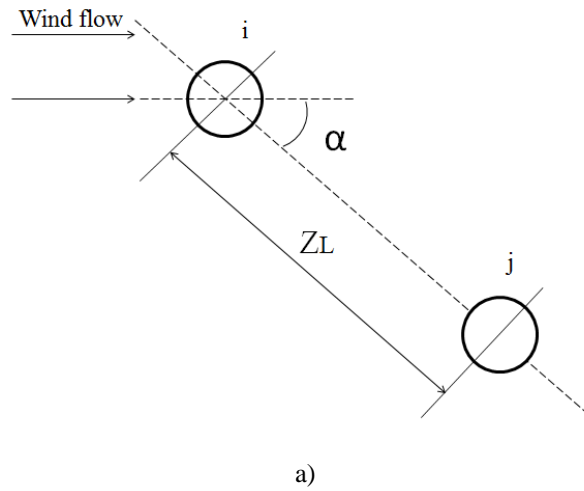


table. 3.3 Schematic positioning of wind turbines relative to each other:
a) top view; b) side-view

$$\Delta h = (h_i + H_i) - (h_j + H_j) \quad (3.4)$$

Where h is the tower height; H is the comparative terrain altitude.

The wake is calculated between each pair of turbines with condition that the wake decay is constant and equals 0.46 m (maximum $\alpha = 25^\circ$).

The model gives a hyperbolic wake expansion. A graphic example of changing array losses with distance for different mutual alignment of turbines is given in the Figure 3.4.

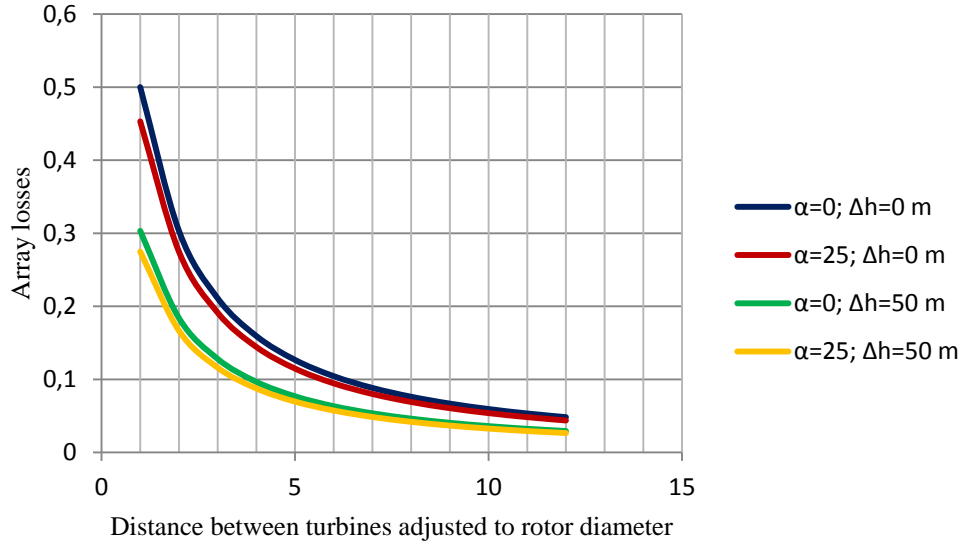


Fig. 3.4 Example of wind farm wake losses

This approximation of wake effects gives results which is believed to be fairly close to real. The value of the losses within 10% for turbines with a downwind distance from 8 to 10 rotor diameters [10].

3.3.5 Calculation of the total wind farm AEP

In circumstances where wind flow has one direction and one type of turbine is under consideration, the annual energy production of a certain wind turbine depends on wind distribution and wake effect value:

$$AEP = T_{op} \int_{V_{in}}^{V_{out}} P(V)(1 - w_i)f_i(V)dV \quad (3.5)$$

Where V_{in} is the cut-in speed; V_{out} is the cut-out speed; $P(V)$ is the power curve of turbine; w_i is the value of wake losses; $f_i(V)$ is the wind distribution.

It is assumed that AEP changes linearly with height. It doesn't correspond to real-life environment, but in conditions of insufficient data it seems as best way to take into account the involvement of height on the AEP assessment.

Depending on the wind park design, the macro addresses to results given in the wake result table situated on the main sheet of the excel file for determination of multiple wake effects between pairs containing the turbine under consideration.

3.3.6 Calculation of NPV, IRR, COE and pay-back period

The NPV is the total of discounted cash flow during the life time of the project. Firstly, the calculations are organized by the cycle where the sum of O&M costs and income for 20 years are computed. The income as well as the O&M cost has a response from AEP. Capital costs are assumed to be done at the first year, so they are estimated outside of cycle as a sum of money for all turbines, their foundations, roads and cables.

The cycle for IRR estimation is organized with a loop that is finished if condition of NPV less than or equal 0 is true. On each step 0,1% is added to the IRR.

COE and payback time are found with equations (2.18) and (2.21) respectively which presented earlier.

As a result four design alternatives with maximum values of NPV, IRR and minimum COE and T_{pb} are put on the main sheet of excel file.

3.4 Case Study

The optimization was exercised on the case area. The limited territory has a square grid shape which is divided on the cells with the size (DxD), where D is a rotor diameter. Each possible location is characterized with X, Y and Z coordinates. The altitude is specified by the Z axis. Also each cell has certain ground conditions. In the work they are categorized into four different types. On the map

of the area they are marked with different colours. The type of soil influences the costs of foundation, cables and roads.

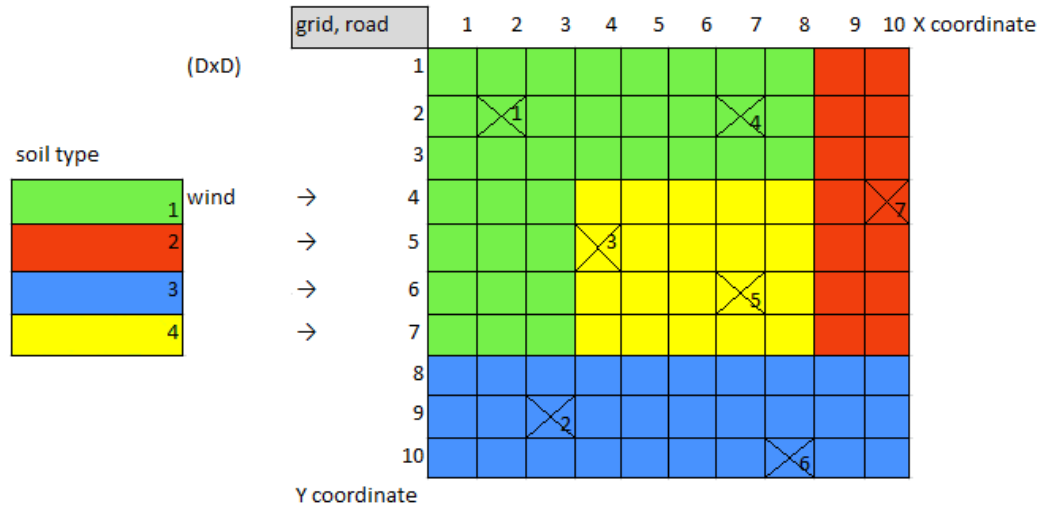


Fig. 3.5 Map of a case area

As mentioned above, the tool is working with locations, numbers of turbines and heights of the towers. In the case example one type of turbine with two possible heights is considered. Each possible variant is registered by a code, which depends on the wind farm configuration:

- 0 – no turbine;
- 1 – turbine with hub height 1;
- 2 – turbine with hub height 2.

For example, the code in case when three turbines with hub heights 100 m are placed in the first, fourth and fifth spot, and two turbines with towers 120 m placed on the second and six spot, it looks the following way 1201120.

The total number of all wind farm design alternatives is

$$K = \sum_{n=1}^N \frac{l!}{(l-n)! n!} h^n = \frac{7!}{(7-1)! 1!} 2^1 + \dots + \frac{7!}{(7-n)! n!} 2^n$$

$$+ \dots + \frac{7!}{(7-7)!7!} 2^7 = 2186$$

3.5 Insertion data and assumptions

1. Best possible locations with best wind conditions are chosen.

Table 3.2 Location data

Position	X	Y	Z	Soil condition
0 (Grid, road)	0	0	0	1
1	2	2	0	1
2	3	9	-5	3
3	4	5	30	4
4	7	2	0	1
5	7	6	30	4
6	8	10	-5	3
7	10	4	10	2

2. Terrain features are studied. The roughness class for area where wind farm is going to be built is 0.3 for villages and areas with low forest (Table 2.1).
3. One type of wind turbine WinWind 3 is considered to be installed with the technical data given in the Table 3.3.

Table 3.3 WinWind 3 turbine data

Characteristic	Value
Rated power	3 MW
Diameter of the blades	100 m
Cut-in speed	3 m/s
Rated wind speed	11 m/s
Cut-out speed	25 m/s
Hub height	100 m and 120 m

Power curve provided by the manufacturer (Figure 3.6).

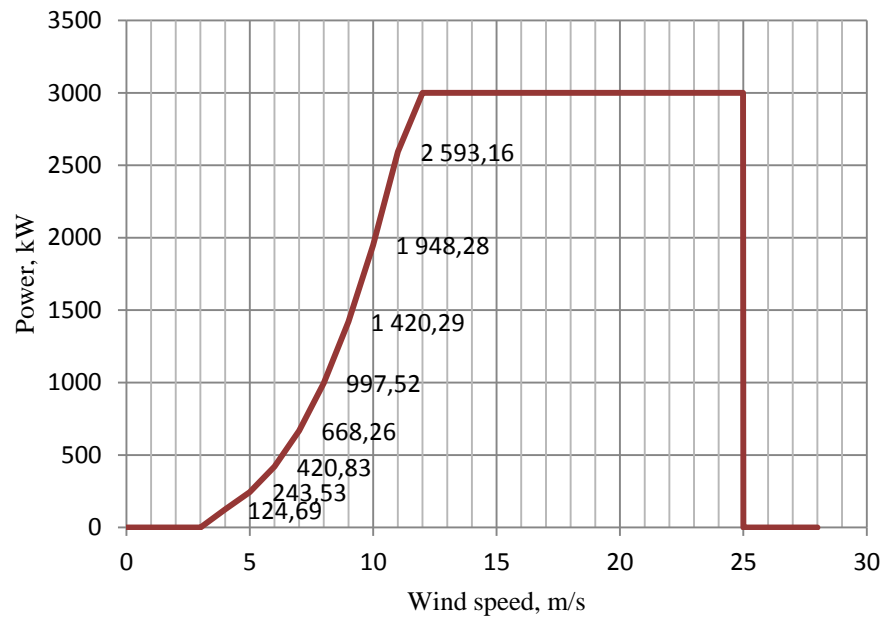


Fig. 3.6 Power curve of the wind turbine.

Investment cost are obtained also from the vendor and presented in the Table 3.4 below.

Table 3.4 Investment costs for 3 MW wind turbine

Cost parameter	Hub height	
	100 m	120 m
Total cost of the turbine	3.6 M€	4.1 M€
Cable	50 €/m	
Road	150 €/m	

The basic cost of foundation is assumed to be 5% from the total cost of the turbine (Table 2.2). The price for the foundation, roads and laying of the cable depends on the soil. In the Table 3.4 base value are given. A ground with bad condition, for example water ground, means construction costs are several times higher than for the optimum soil. In the following table the costs for wind farm components, which are depending on soil, are available.

Table 3.5 Foundation and road costs depending on soil condition

Soil condition	Foundation, M€		Road, €/m
	100 m	120 m	
1	0.18	0.205	150
2	0.3	0.342	300
3	0.42	0.479	450
4	0.54	0.615	600

4. The wind farm is connected to the grid 110 kV through the transformer 110/20 kV. The substation has a fixed price 1 M€.
5. Over the lifetime of the wind farm, the annual O&M costs are assumed to be 10 €/MWh.
6. The wind data from meteorological measurement station including prevailing wind direction and wind histogram are given. In this model the wind is coming from the West (Figure 3.5).

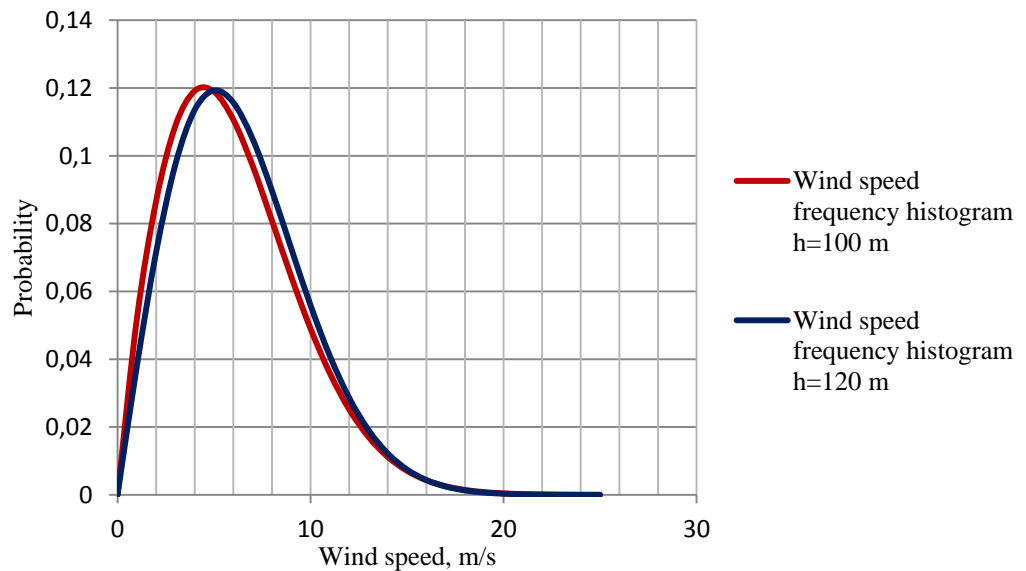


Fig. 3.7 Wind distribution for case study

The Weibull probability density function has following parameters for the height 100 m $k=1.85$, $c=6.8$ and for 120 m the values are $k=2$, $c=7.19$.

Therefore mean wind speed on the height 100 m is 6.04 m/s and on the height 120 m is 6.37 m/s.

7. The AEP changes linear with different heights. The function obtained from the calculated levels of AEP on the height 100 and 120 m.
8. The electricity selling prices for different periods of the project lifetime, which are taken in the calculation of economic parameters of NPV, IRR, COE and T_{pb} , is presented in the Table 2.3.

Table 3.6 Selling price for wind energy produced

Period of time	Price
$t \leq 3 a$	105.3 €/MWh
$3 a < t \leq 9 a$	83.5 €/MWh
$9 a < t \leq 20 a$	50 €/MWh

9. For the interest rate a typical value of 4 % is used.
10. The wake effect, reducing the wind speed after the upstream turbine is taken into account as a percentage, by which the production capacity of the downstream turbine is reduced. It depends on the distance between wind turbines. In this work the angle of the wake cone is assumed to be 25 degrees, i.e. each meter behind the turbine the wake zone is expanding for $\alpha=0.46$ m.
11. The project's life time is 20 years.
12. The operational time T_{op} is assumed as 90% of the year.

3.6 Analysis of computation results

In this section the results of calculation of the technical and as well economic parameters for the best design alternatives of the wind farm from an economical

point of view are presented. The cost structure is printed in the Table 3.7 below. Schematic layouts of the variants are depicted on the Figure 3.8.

Table 3.7 Calculation data

Estimated parameter	NPV max	IRR max	COE min	Tpb min
Code of the variant	2001111	0001101		
Total AEP, MWh	29288.70	18364.59		
Investment costs, k€	21918.11	13314.14		
O&M costs*, k€	3980.43	2495.81		
Income*, k€	28969.36	18164.36		
NPV, k€	3070.82	2354.41		
IRR	0.06	0.065		
COE, €/MWh	65.07	63.35		
Tpb, year	13.88	13.53		

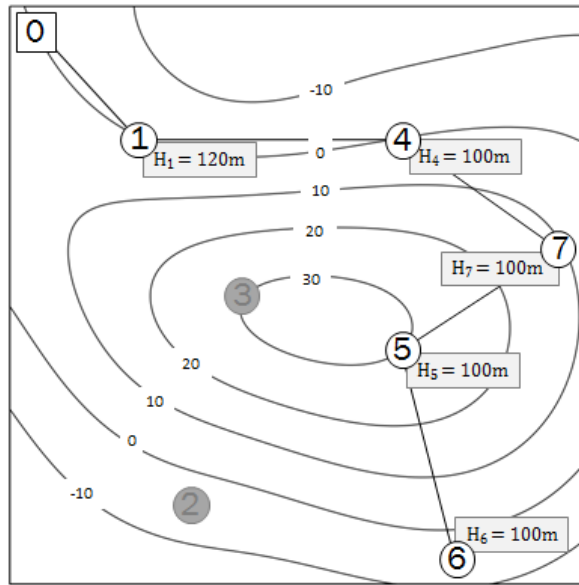
*discounted sum for 20 year

In consequence of the computation, two alternatives were selected in respect to NPV, IRR, COE and pay-back time methods of economic analysis. Whereas the first variant shows the largest NPV value, the second is selected according to max IRR and min COE and T_{pb} .

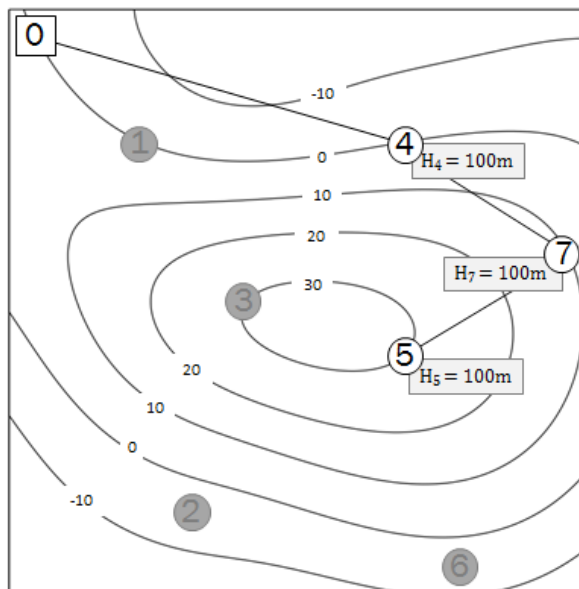
These two projects have a different size, regarding its characterised investments. The first alternative contains 5 turbines with a rated capacity of 3 MW each. Total AEP of the wind farm is around 29.3 GWh per year. In the second variant 3MW turbines are in number of three. Total AEP in that case is 18.4 GWh per year.

The variant a) is 65% more cost-intensive compare to variant b), but the value of yield which will be obtained by the stakeholder is 30% more and amounts 3.07 M€. While the second variant has slightly higher IRR factor, such wise it is less risky to invest in that project. However the difference in IRR, COE and pay-back

time between alternatives is not considerable. In this way the first variant of the wind farm configuration is likely to be preferable.



a)



b)

Fig. 3.8 Configuration of the final design alternatives of the wind farm according to economical criteria: a) maximum NPV; b) maximum IRR, minimum COE and T_{pb}

The final conclusion can only be made after a full analysis of the risks that contain the project realization. The decision making is based on a lot of assumptions of both economic and technical variables, which leads to the tendency that forecastings can be incorrect. On this stage the sensitivity analysis is making statements about the stability of the project to imprecise assumptions.

3.7 Sensitivity Analysis.

Each business project contains a certain level of risk, due to the uncertainty of input parameters, on which the decision making is based. The optimal solution needs to be tested on a variety of factors, which have an impact on the output. The key parameters of the project, which is considered to be found the optimal solution for, are NPV, IRR, COE and T_{pb} . The variation of the factors, which have a direct effect on these values and which were assumed, identify the robustness of the project.

The aim of the analysis is testing the optimal solution's financial stability on changings and to define the sensibility of the result on each variable.

An important step of the sensitivity analysis is the compilation of the influencing factors. The main components of wind farm economy are:

1. Investment costs;
2. O&M costs;
3. Income which depends on:
 - Wind speed;
 - Wake effect;
 - Discount rate;
 - Operational time T_{op} during the year;
 - Lifetime of the project.

The substantiality of the project is considered with 20 % of variation parameters in both decreasing and increasing directions. Each variable is accounted separately.

It is important to mention that model of the wind turbine also has a strong impact to the value of the capital costs, O&M costs and profit. By virtue of the fact that one type of turbine is considered and due to a lack of data, the changes of technical and cost parameters of it are not evaluated in the sensitivity analysis.

Results are showed in the Table 3.8 and demonstrative diagrams, presented in Figures 3.9 – 3.12.

The most important variables according to the sensitivity analysis can be divided in groups, to characterise the sensitive of the output to them form the most to less influencing.

- First group:
 - Wind speed;
 - Electricity selling price;
 - Capital costs;
 - Operational time.
- Second group:
 - Life time;
 - Interest rate.
- Third group:
 - O&M cost;
 - Wake effect.

As expected, the wind speed has a crucial role. Its overestimation even for 10% already leads to a complete bankruptcy of the whole project as all possible alternatives are becoming loss-making. Stronger winds increase the profitability of current project more than two and half times with each 10% of parameter variation. Thereby the most beneficial variant in reality is the one with a higher number of installations.

Table 3.8 Sensitivity of wind farm calculation data to various parameters.

Parameter	Variation	NPV, M€	IRR, M€	COE, €/MWh	<i>T_{pb}</i> , year	AEP, MWh	Investment costs, M€	O&M costs, M€	Income, M€	Optimal configuration
-	0%	3070.82	6.00	65.06	13.88	29288.70	21918.11	3980.43	28969.36	2001111
Wind speed	-20%	-6705.34	0.10	100.45	20.91	17830.38	21918.11	2423.21	17635.98	-
	-10%	-1799.15	2.90	78.39	16.53	23580.77	21918.11	3204.70	23323.66	-
	10%	8233.11	9.10	55.64	12.00	35339.24	21918.11	4802.72	34953.93	2221111
	20%	13739.18	12.20	48.59	10.60	41792.72	21918.11	5679.77	41337.05	2221111
Wake effect	-20%	3306.01	6.10	64.55	13.77	29564.35	21918.11	4017.89	29242.01	2221111
	-10%	3197.40	6.10	64.79	13.82	29437.06	21918.11	4000.59	29116.10	2021111
	10%	2923.98	5.90	65.39	13.94	29116.59	21918.11	3957.04	28799.13	2001111*
	20%	2754.56	5.80	65.77	14.02	28918.01	21918.11	3930.05	28602.72	0001111
Top, year	-20%	-1926.96	2.80	78.83	16.61	23430.96	21918.11	3184.34	23175.49	-
	-10%	571.93	4.40	71.18	15.09	26359.83	21918.11	3582.39	26072.42	0001111
	10%	5569.72	7.50	60.06	12.88	32217.57	21918.11	4378.47	31866.30	2221111
	+11.1%	5847.37	7.70	59.56	12.78	32543.00	21918.11	4422.70	32188.18	2221111
O&M costs	-20%	3866.91	6.40	63.06	13.29	29288.70	21918.11	3184.34	28969.36	2221111
	-10%	3468.87	6.20	64.06	13.58	29288.70	21918.11	3582.39	28969.36	2001111*
	10%	2672.78	5.70	66.06	14.17	29288.70	21918.11	4378.47	28969.36	2001111*
	20%	2274.74	5.50	67.06	14.46	29288.70	21918.11	4776.52	28969.36	2001111*

Capital costs	-20%	7310.44	9.60	54.41	11.76	29288.70	17678.49	3980.43	28969.36	2221111
	-10%	4785.33	7.30	60.76	13.02	29288.70	20203.60	3980.43	28969.36	1111111
	10%	951.01	4.60	70.39	14.93	29288.70	24037.92	3980.43	28969.36	0001111
	20%	-1168.80	3.40	75.72	15.99	29288.70	26157.73	3980.43	28969.36	-
Lifetime	-20%	800.33	4.70	74.22	12.45	29288.70	21918.11	3412.81	26131.24	0001111
	-10%	1980.08	5.40	69.11	13.19	29288.70	21918.11	3707.74	27605.93	2001111*
	10%	4079.28	6.40	61.78	14.52	29288.70	21918.11	4232.54	30229.93	2221111
	20%	5011.65	6.80	59.08	15.14	29288.70	21918.11	4465.64	31395.40	2221111
Interest rate,	-20%	4561.47	6.00	61.24	13.88	29288.70	21918.11	4277.93	30757.51	2221111
	-10%	3798.31	6.00	63.13	13.88	29288.70	21918.11	4125.21	29841.63	2221111
	10%	2376.90	6.00	67.03	13.88	29288.70	21918.11	3843.08	28138.10	2001111*
	20%	1714.60	6.00	69.04	13.88	29288.70	21918.11	3712.72	27345.43	0001111
Electricity selling price	-20%	-2723.05	2.20	65.06	17.34	29288.70	21918.11	3980.43	23175.49	-
	-10%	173.89	4.20	65.06	15.42	29288.70	21918.11	3980.43	26072.42	0001101
	10%	5967.76	7.70	65.06	12.61	29288.70	21918.11	3980.43	31866.30	2221111
	20%	8864.70	9.40	65.06	11.56	29288.70	21918.11	3980.43	34763.23	2221111

‘-‘ means that there is no optimal alternative. All projects are loss making (NPV<0).

‘*’ the optimal solution stays the same.

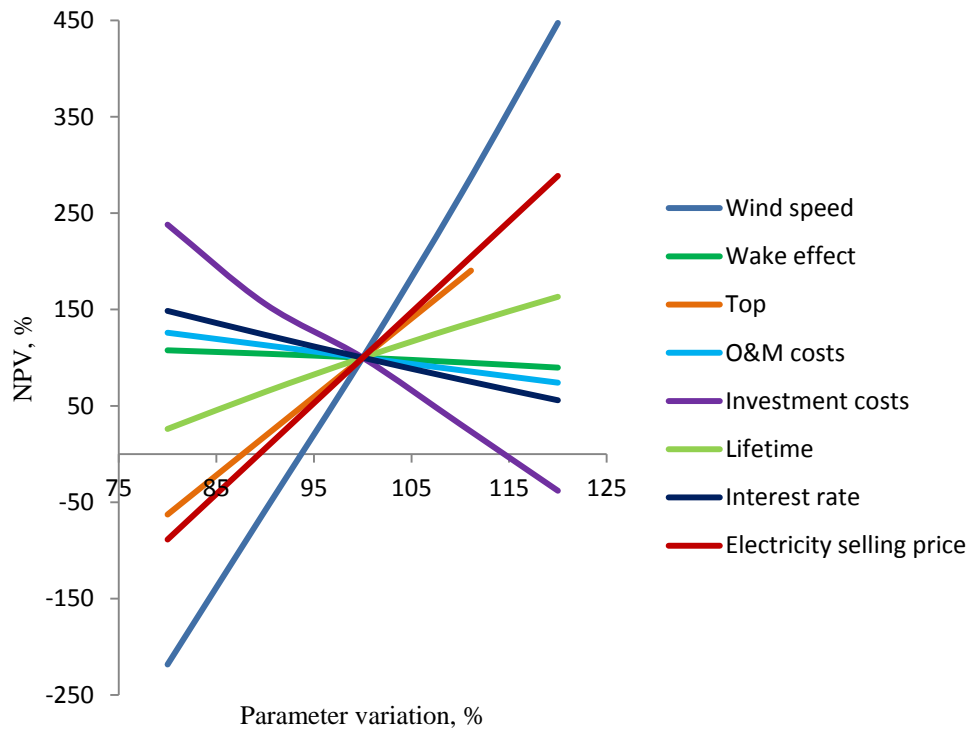


Fig 3.9 Sensitivity of the NPV to various parameters

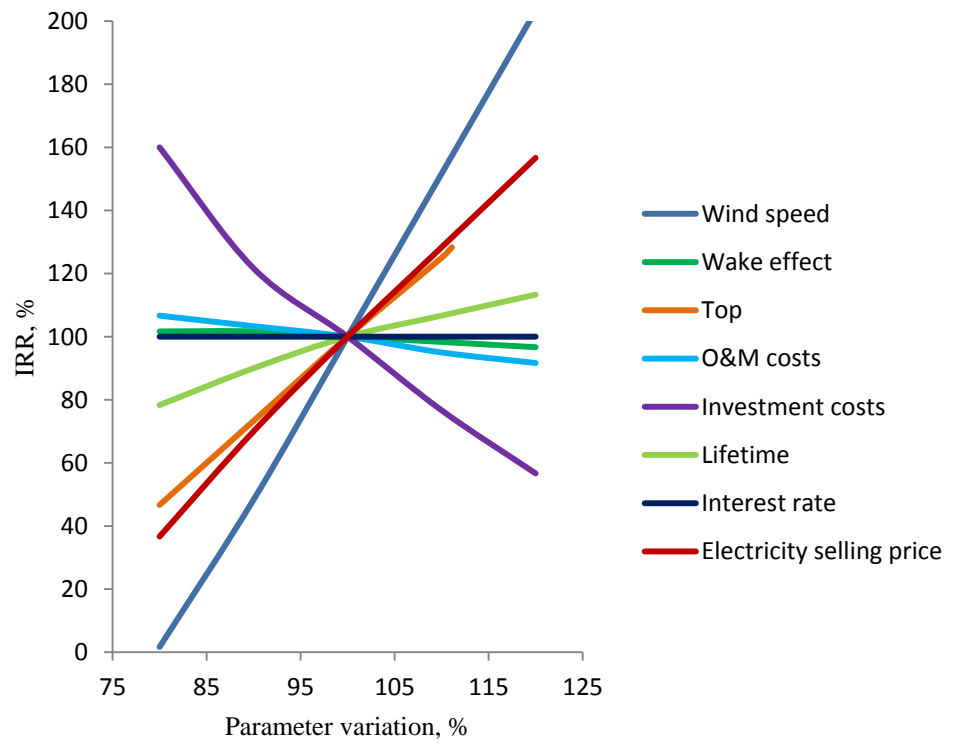


Fig 3.10 Sensitivity of the IRR to various parameters

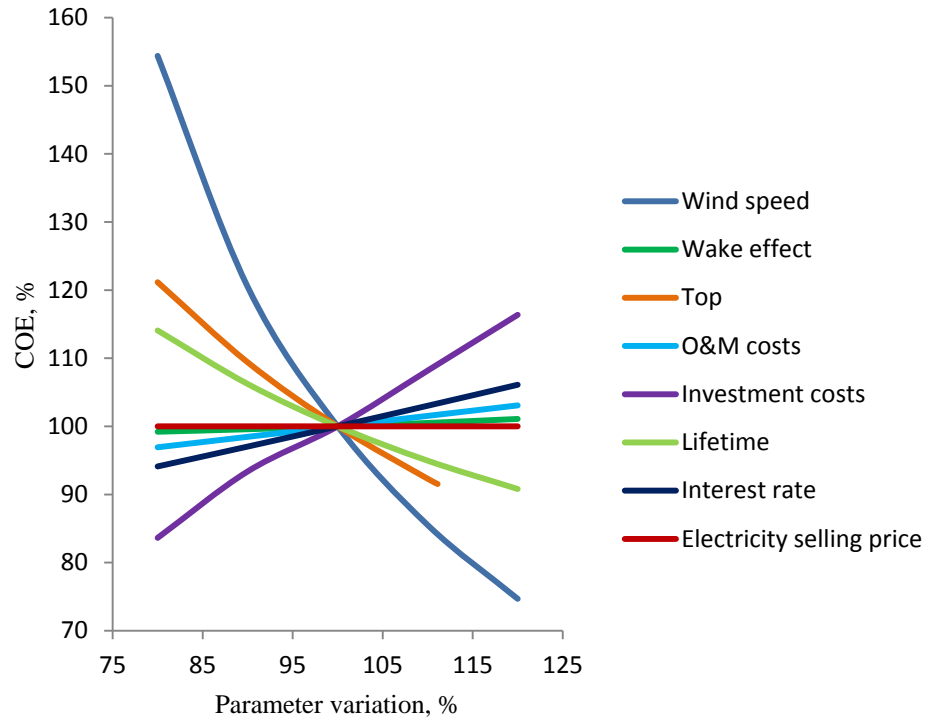


Fig 3.11 Sensitivity of the COE to various parameters

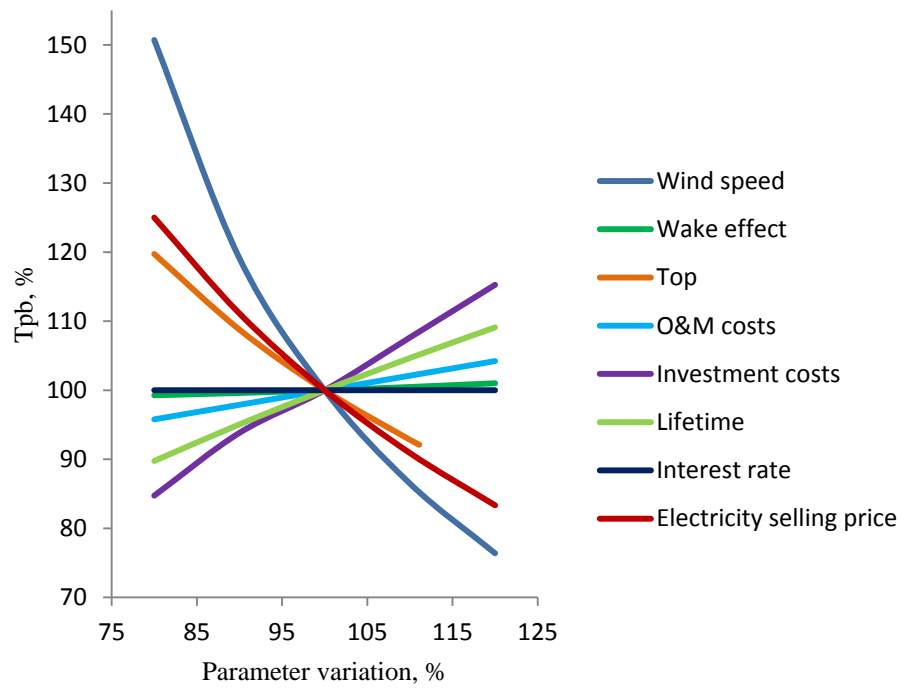


Fig 3.12 Sensitivity of the T_{pb} to various parameters

Another important factor is the electricity selling price. Without government support, which enables to set prices on certain level by feed-in tariff, the risk of the project is quite strong, due to big uncertainties in price fluctuation on the electricity market. The electricity selling price influences the choice of the optimal configuration in the same kind as the wind speed but not as dramatically. More precisely, the changes of the variable in increments of 10% lead to a change in absolute result by 100%, depending on which direction these changes are made.

Underestimation as well as overestimation of the capital costs can be a reason of big movements in financial situation of the project. With rising prices the wealth of the stakeholder goes down and vice versa. The operational time has around the same influence on the NPV according to sensitivity analysis. On the end result the percentage of NPV changes has a similar value of impact as has the electricity selling price. The decision made in order to build the best alternative does not stay the same by varying the parameter. Therefore on the stage of variant comparison it is highly important to make precise assumptions.

The second group of variables doesn't have such a huge influence on the absolute output as first one. Small changes in interest rate and lifetime don't lead to a strong risk. If the magnitude of the discount rate will rise more than IRR value the project is not desirable to implement. The lifetime has 50% and interest rate has around 25% step to each 10% of the parameters variation.

The last group are components that affect the total output least compared to the other variables. This group includes O&M costs and wake effect between turbines. O&M costs are growing during project life time by the level from 1 to 5% from total investment cost [18]. Also the small changes in the AEP of the wind farm is not seriously affecting the volume of energy production. Of course it brings revision in choosing of optimal variant, but the NPV of the one under

consideration is little sensitive to variation of these parameters. The rate of the NPV changes is less than 10 % to each 10% of the step variation.

The influence on the other economic parameters on which the decision-making is based such as IRR, COE and T_{pb} have roughly the same picture of dependence from varies. These three factors are only slightly dependent on changes in the discount rate and the wake effect value. Given that IRR and T_{pb} don't consider the time value of money, their values are not changing when the discount rate is varying. The same is valid for the COE, since it doesn't depend on the electricity selling price.

4 Conclusion

The issue of the wind farm optimization was discussed and a basic tool for solving that complex problem was developed. The best solution is found by using economic methods to evaluate the profitability and desirability of the wind park project implementation.

The Excel based tool is working with numbers of installed wind mills, tower heights, on which the wind turbines are mounted, and possible locations on the area. The wind farm cost model consists of three main components. The capital cost, the O&M cost and the income are calculated for each possible design variant. The optimal configuration with balance between expenditures and revenue which gives the higher yield for the stakeholder is identified.

The wind farm optimization algorithm is based on several important assumptions. The simulation of the wind flow is performed by the application of the Weibull probability density function and by a given privilege wind direction. The wind gradient is determined by the roughness class of the terrain. One type of wind turbine with a rated capacity of 3 MW is used in optimization model. The AEP of the individual wind mill is calculated by taking into account the hub

height and absolute level of the terrain surface, likewise by considering the multiple influence between turbines due to the wake effect is created by rotor blades.

The run code of the program contains a cycle, which determine the optimal road and local distribution network configuration, depending on the considered variant.

The calculation of the wind farm investment is approximated to real condition. The cost components of the installation such as foundation, roads and cable laying vary by the type of the ground, which is specified for each spot of the area.

NPV, IRR, COE and T_{pb} are calculated for each possible design configuration of the wind farm. As a result the variant with the best conditions is presented.

The important part of the work is the sensitivity analysis. This analysis gives an opportunity to observe which influence each varied parameter, which was assumed before, has on the actual outcome. The robustness of the optimal solution is considered by a variation of the main wind farm economic components and factors influencing them, such as the wind speed, the wake effect, the project life time, the discount rate, etc.

The result demonstrates low sustainability of the wind farm economic values to these changes. The variables are divided in three groups according to their influence on the decision making. Thereby wind speed is the most crucial parameter, of which already small variations globally affect the total output and forms different configurations of the wind farm.

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Appendix

Run code of the optimization algorithm

Run code for optimization of the wind farm installations given below. Programming was realized in Office application Excel by VBA language.

```
Sub Macro()
```

```
Dim NPV, AEP, Income
```

```
Tpbmin = 99999
```

```
COEmin = 99999
```

```
annuity = (Cells(11, 2).Value) / 100 / (1 - 1 / (1 + (Cells(11, 2).Value) / 100) ^ Cells(10, 2).Value)
```

```
For i = 294 To 2479
```

```
SumAEP = 0
```

```
SumOMCost = 0
```

```
SumIncome = 0
```

```
SumInvCost = 0
```

```
NPV = 0
```

```
COE = 0
```

```
mindis = 0
```

```
empty1 = 0
```

```
empty2 = 0
```

```
empty3 = 0
```

```
empty4 = 0
```

```
empty5 = 0
```

```
empty6 = 0
```

```
RoadCost = 0
```

```
Tpb = 0
```

```
AvSumIncome = 0
```

```
AverageIncome = 0
```

```
For j = 2 To 8
```

```
    If Cells(i, j - 1).Value = 0 Then
```

```
If empty1 = 0 Then
  empty1 = j
Else
  If empty2 = 0 Then
    empty2 = j
  Else
    If empty3 = 0 Then
      empty3 = j
    Else
      If empty4 = 0 Then
        empty4 = j
      Else
        If empty5 = 0 Then
          empty5 = j
        Else
          If empty6 = 0 Then
            empty6 = j
          End If
        End If
      End If
    End If
  End If
End If
End If
End If
```

```
Next
```

```
mindis1 = 9999
mina1 = 0
minb1 = 0
mindis2 = 9999
mina2 = 0
minb2 = 0
mindis3 = 9999
mina3 = 0
minb3 = 0
mindis4 = 9999
mina4 = 0
```

```

minb4 = 0
mindis5 = 9999
mina5 = 0
minb5 = 0
mindis6 = 9999
mina6 = 0
minb6 = 0
mindis7 = 9999
mina7 = 0
minb7 = 0
RoadCost1 = 0
RoadCost2 = 0
RoadCost3 = 0
RoadCost4 = 0
RoadCost5 = 0
RoadCost6 = 0
RoadCost7 = 0
GCCost1 = 0
GCCost2 = 0
GCCost3 = 0
GCCost4 = 0
GCCost5 = 0
GCCost6 = 0
GCCost7 = 0

```

```

For a = 1 To 8

```

```

    For b = 1 To 8

```

```

        If (a <> empty1 And a <> empty2 And a <> empty3 And a <> empty4 And a <> empty5
            And a <> empty6 And b <> empty1 And b <> empty2 And b <> empty3 And b <>
            empty4 And b <> empty5 And b <> empty6) Then

```

```

            If a <> b Then

```

```

                dis = Cells(a + 228, b + 1).Value

```

```

                If dis < mindis1 Then

```

```

                    mindis1 = dis

```

```

                    mina1 = a

```

```

                    minb1 = b

```

```

                    RoadCost1 = mindis1 * Cells(31, 2).Value * Cells(mina1 + 276, minb1 +
                    1).Value * Cells(64, 4).Value

```

```

        GCCost1 = mindis1 * Cells(31, 2).Value * Cells(mina1 + 276, minb1 + 1).Value
        * Cells(42, 3).Value
    End If
End If
End If
Next
Next

If empty6 = 0 Then
    For a = 1 To 8
        For b = 1 To 8
            If (a <> empty1 And a <> empty2 And a <> empty3 And a <> empty4 And a <> emp-
            ty5 And a <> empty6 And b <> empty1 And b <> empty2 And b <> empty3 And b <>
            empty4 And b <> empty5 And b <> empty6) Then
                If ((a <> b) And ((a = mina1 And b <> minb1) Or (a = minb1 And b <> mina1)))
                Then
                    dis = Cells(a + 228, b + 1).Value
                    If dis < mindis2 Then
                        mindis2 = dis
                        mina2 = a
                        minb2 = b
                        RoadCost2 = mindis2 * Cells(31, 2).Value * Cells(mina2 + 276, minb2 +
                        1).Value * Cells(64, 4).Value
                        GCCost2 = mindis2 * Cells(31, 2).Value * Cells(mina2 + 276, minb2 +
                        1).Value * Cells(42, 3).Value
                    End If
                End If
            End If
        Next
    Next
End If

If empty5 = 0 Then
    For a = 1 To 8
        For b = 1 To 8
            If (a <> empty1 And a <> empty2 And a <> empty3 And a <> empty4 And a <> emp-
            ty5 And a <> empty6 And b <> empty1 And b <> empty2 And b <> empty3 And b <>
            empty4 And b <> empty5 And b <> empty6) Then

```

```

    If ((a <> b) And ((a = mina1 And b <> minb1 And b <> minb2) Or (b <> mina1 And
a = minb1 And b <> minb2) Or (b <> mina1 And b <> minb1 And a = minb2))) Then
        dis = Cells(a + 228, b + 1).Value
        If dis < mindis3 Then
            mindis3 = dis
            mina3 = a
            minb3 = b
            RoadCost3 = mindis3 * Cells(31, 2).Value * Cells(mina3 + 276, minb3 +
1).Value * Cells(64, 4).Value
            GCCost3 = mindis3 * Cells(31, 2).Value * Cells(mina3 + 276, minb3 +
1).Value * Cells(42, 3).Value
        End If
    End If
End If
Next
Next
End If

If empty4 = 0 Then
    For a = 1 To 8
        For b = 1 To 8
            If (a <> empty1 And a <> empty2 And a <> empty3 And a <> empty4 And a <> emp-
ty5 And a <> empty6 And b <> empty1 And b <> empty2 And b <> empty3 And b <>
empty4 And b <> empty5 And b <> empty6) Then
                If ((a <> b) And ((a = mina1 And b <> minb1 And b <> minb2 And b <> minb3) Or
(b <> mina1 And a = minb1 And b <> minb2 And b <> minb3) Or (b <> mina1 And b
<> minb1 And a = minb2 And b <> minb3) Or (b <> mina1 And b <> minb1 And b <>
minb2 And a = minb3))) Then
                    dis = Cells(a + 228, b + 1).Value
                    If dis < mindis4 Then
                        mindis4 = dis
                        mina4 = a
                        minb4 = b
                        RoadCost4 = mindis4 * Cells(31, 2).Value * Cells(mina4 + 276, minb4 +
1).Value * Cells(64, 4).Value
                        GCCost4 = mindis4 * Cells(31, 2).Value * Cells(mina4 + 276, minb4 +
1).Value * Cells(42, 3).Value
                    End If
                End If
            End If
        Next
    Next
End If

```

```

        End If
    End If
Next
Next
End If
If empty3 = 0 Then
    For a = 1 To 8
        For b = 1 To 8
            If (a <> empty1 And a <> empty2 And a <> empty3 And a <> empty4 And a <> empty5 And a <> empty6 And b <> empty1 And b <> empty2 And b <> empty3 And b <> empty4 And b <> empty5 And b <> empty6) Then
                If ((a <> b) And ((a = mina1 And b <> minb1 And b <> minb2 And b <> minb3 And b <> minb4) Or (b <> mina1 And a = minb1 And b <> minb2 And b <> minb3 And b <> minb4) Or (b <> mina1 And b <> minb1 And a = minb2 And b <> minb3 And b <> minb4) Or (b <> mina1 And b <> minb1 And b <> minb2 And a = minb3 And b <> minb4) Or (b <> mina1 And b <> minb1 And b <> minb2 And b <> minb3 And a = minb4))) Then
                    dis = Cells(a + 228, b + 1).Value
                    If dis < mindis5 Then
                        mindis5 = dis
                        mina5 = a
                        minb5 = b
                        RoadCost5 = mindis5 * Cells(31, 2).Value * Cells(mina5 + 276, minb5 + 1).Value * Cells(64, 4).Value
                        GCCost5 = mindis5 * Cells(31, 2).Value * Cells(mina5 + 276, minb5 + 1).Value * Cells(42, 3).Value
                    End If
                End If
            End If
        Next
    Next
End If

If empty2 = 0 Then
    For a = 1 To 8
        For b = 1 To 8

```

If (a <> empty1 And a <> empty2 And a <> empty3 And a <> empty4 And a <> empty5 And a <> empty6 And b <> empty1 And b <> empty2 And b <> empty3 And b <> empty4 And b <> empty5 And b <> empty6) Then

If ((a <> b) And ((a = mina1 And b <> minb1 And b <> minb2 And b <> minb3 And b <> minb4 And b <> minb5) Or (b <> mina1 And a = minb1 And b <> minb2 And b <> minb3 And b <> minb4 And b <> minb5) Or (b <> mina1 And b <> minb1 And a = minb2 And b <> minb3 And b <> minb4 And b <> minb5) Or (b <> mina1 And b <> minb1 And b <> minb2 And a = minb3 And b <> minb4 And b <> minb5) Or (b <> mina1 And b <> minb1 And b <> minb2 And b <> minb3 And a = minb4 And b <> minb5) Or (b <> mina1 And b <> minb1 And b <> minb2 And b <> minb3 And b <> minb4 And a = minb5))) Then

dis = Cells(a + 228, b + 1).Value

If dis < mindis6 Then

mindis6 = dis

mina6 = a

minb6 = b

RoadCost6 = mindis6 * Cells(31, 2).Value * Cells(mina6 + 276, minb6 + 1).Value * Cells(64, 4).Value

GCCost6 = mindis6 * Cells(31, 2).Value * Cells(mina6 + 276, minb6 + 1).Value * Cells(42, 3).Value

End If

End If

End If

Next

Next

End If

If empty1 = 0 Then

For a = 1 To 8

For b = 1 To 8

If (a <> empty1 And a <> empty2 And a <> empty3 And a <> empty4 And a <> empty5 And a <> empty6 And b <> empty1 And b <> empty2 And b <> empty3 And b <> empty4 And b <> empty5 And b <> empty6) Then

If ((a <> b) And ((a = mina1 And b <> minb1 And b <> minb2 And b <> minb3 And b <> minb4 And b <> minb5 And b <> minb6) Or (b <> mina1 And a = minb1 And b <> minb2 And b <> minb3 And b <> minb4 And b <> minb5 And b <> minb6) Or (b <> mina1 And b <> minb1 And a = minb2 And b <> minb3 And b <> minb4 And b <> minb5 And b <> minb6) Or (b <> mina1 And b <> minb1 And b <> minb2 And a =


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minb3 And b <> minb4 And b <> minb5 And b <> minb6) Or (b <> mina1 And b <>
minb1 And b <> minb2 And b <> minb3 And a = minb4 And b <> minb5 And b <>
minb6) Or (b <> mina1 And b <> minb1 And b <> minb2 And b <> minb3 And b <>
minb4 And a = minb5 And b <> minb6) Or (b <> mina1 And b <> minb1 And b <>
minb2 And b <> minb3 And b <> minb4 And b <> minb5 And a = minb6))) Then
    dis = Cells(a + 228, b + 1).Value
    If dis < mindis7 Then
        mindis7 = dis
        mina7 = a
        minb7 = b
        RoadCost7 = mindis7 * Cells(31, 2).Value * Cells(mina7 + 276, minb7 +
1).Value * Cells(64, 4).Value
        GCCost7 = mindis7 * Cells(31, 2).Value * Cells(mina7 + 276, minb7 +
1).Value * Cells(42, 3).Value
    End If
End If
End If
Next
Next
End If

If empty1 = 0 Then
    mindis = mindis1 + mindis2 + mindis3 + mindis4 + mindis5 + mindis6 + mindis7
    RoadCost = RoadCost1 + RoadCost2 + RoadCost3 + RoadCost4 + RoadCost5 + RoadCost6
    + RoadCost7
    GCCost = GCCost1 + GCCost2 + GCCost3 + GCCost4 + GCCost5 + GCCost6 + GCCost7
End If

If (empty2 = 0 And empty1 <> 0) Then
    mindis = mindis1 + mindis2 + mindis3 + mindis4 + mindis5 + mindis6
    RoadCost = RoadCost1 + RoadCost2 + RoadCost3 + RoadCost4 + RoadCost5 + RoadCost6
    GCCost = GCCost1 + GCCost2 + GCCost3 + GCCost4 + GCCost5 + GCCost6
End If

If empty3 = 0 And empty2 <> 0 Then
    mindis = mindis1 + mindis2 + mindis3 + mindis4 + mindis5
    RoadCost = RoadCost1 + RoadCost2 + RoadCost3 + RoadCost4 + RoadCost5
    GCCost = GCCost1 + GCCost2 + GCCost3 + GCCost4 + GCCost5
End If

If empty4 = 0 And empty3 <> 0 Then

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mindis = mindis1 + mindis2 + mindis3 + mindis4
RoadCost = RoadCost1 + RoadCost2 + RoadCost3 + RoadCost4
GCCost = GCCost1 + GCCost2 + GCCost3 + GCCost4
End If
If empty5 = 0 And empty4 <> 0 Then
    mindis = mindis1 + mindis2 + mindis3
    RoadCost = RoadCost1 + RoadCost2 + RoadCost3
    GCCost = GCCost1 + GCCost2 + GCCost3
End If
If empty6 = 0 And empty5 <> 0 Then
    mindis = mindis1 + mindis2
    RoadCost = RoadCost1 + RoadCost2
    GCCost = GCCost1 + GCCost2
End If
If empty6 <> 0 Then
    mindis = mindis1
    RoadCost = RoadCost1
    GCCost = GCCost1
End If
'Cells(i, 16).Value = mindis
FoundCost = 0
TurbCost = 0

For j = 1 To 7
    If Cells(i, j).Value = 1 Then
        If Cells(j + 20, 5).Value = 1 Then
            FoundCost = FoundCost + Cells(64, 2).Value * 10 ^ 6
        End If
        If Cells(j + 20, 5).Value = 2 Then
            FoundCost = FoundCost + Cells(65, 2).Value * 10 ^ 6
        End If
        If Cells(j + 20, 5).Value = 3 Then
            FoundCost = FoundCost + Cells(66, 2).Value * 10 ^ 6
        End If
        If Cells(j + 20, 5).Value = 4 Then
            FoundCost = FoundCost + Cells(67, 2).Value * 10 ^ 6
        End If
        TurbCost = TurbCost + Cells(40, 3).Value * 10 ^ 6
    End If
End For

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Else
    FoundCost = FoundCost
    TurbCost = TurbCost
End If

If (Cells(i, j).Value = 2) Then
    If Cells(j + 20, 5).Value = 1 Then
        FoundCost = FoundCost + Cells(64, 3).Value * 10 ^ 6
    End If
    If Cells(j + 20, 5).Value = 2 Then
        FoundCost = FoundCost + Cells(65, 3).Value * 10 ^ 6
    End If
    If Cells(j + 20, 5).Value = 3 Then
        FoundCost = FoundCost + Cells(66, 3).Value * 10 ^ 6
    End If
    If Cells(j + 20, 5).Value = 4 Then
        FoundCost = FoundCost + Cells(67, 3).Value * 10 ^ 6
    End If
    TurbCost = TurbCost + Cells(41, 3).Value * 10 ^ 6
Else
    FoundCost = FoundCost
    TurbCost = TurbCost
End If
Next

For j = 1 To 7
    AEP = 0
    w = 0
    For l = 1 To 7
        If (Cells(i, l).Value) = 0 Then
            AEP = AEP
        Else
            If (Cells(i, l).Value = Cells(i, j).Value) And (Cells(i, j).Value = 1) Then
                w = w + (Cells(j + 243, l + 2).Value)
                AEP = (Cells(225, 1).Value + Cells(225, 2).Value * (Cells(40, 2).Value + Cells(j +
                20, 4).Value)) * (1 - w) * 10 ^ (-3)
            End If
            If (Cells(i, l).Value = Cells(i, j).Value) And (Cells(i, j).Value = 2) Then

```

```

w = w + (Cells(j + 243, 1 + 2).Value)
AEP = (Cells(225, 1).Value + Cells(225, 2).Value * (Cells(41, 2).Value + Cells(j +
20, 4).Value)) * (1 - w) * 10 ^ (-3)
End If
If (Cells(i, 1).Value = 1) And (Cells(i, j).Value = 2) Then
w = w + (Cells(j + 254, 1 + 2).Value)
AEP = (Cells(225, 1).Value + Cells(225, 2).Value * (Cells(41, 2).Value + Cells(j +
20, 4).Value)) * (1 - w) * 10 ^ (-3)
End If
If (Cells(i, 1).Value = 2) And (Cells(i, j).Value = 1) Then
w = w + (Cells(j + 265, 1 + 2).Value)
AEP = (Cells(225, 1).Value + Cells(225, 2).Value * (Cells(40, 2).Value + Cells(j +
20, 4).Value)) * (1 - w) * 10 ^ (-3)
End If
End If
Next
'Cells(i, j + 7).Value = w
'Cells(i, j + 14).Value = AEP
SumAEP = SumAEP + AEP
Next

SumInvCost = TurbCost + Cells(44, 3).Value * 10 ^ 6 + RoadCost + GCCost + FoundCost

For t = 1 To (Cells(10, 2).Value)
Income = (Cells(71, t + 1).Value) * SumAEP * 1 / (1 + Cells(11, 2).Value / 100) ^ t
SumIncome = SumIncome + Income
OMCost = (Cells(45, 3).Value) * SumAEP * 1 / (1 + Cells(11, 2).Value / 100) ^ t
SumOMCost = SumOMCost + OMCost
Next
NPV = SumIncome - SumOMCost - SumInvCost

If NPVmax < NPV Then
NPVmax = NPV
iNPVmax = i
AEPmax = SumAEP
SumIncomemax = SumIncome
SumOMCostmax = SumOMCost
SumInvCostmax = SumInvCost

```

$\text{mindis1max} = \text{mindis1}$
 $\text{mina1max} = \text{mina1} - 1$
 $\text{minb1max} = \text{minb1} - 1$
 $\text{mindis2max} = \text{mindis2}$
 $\text{mina2max} = \text{mina2} - 1$
 $\text{minb2max} = \text{minb2} - 1$
 $\text{mindis3max} = \text{mindis3}$
 $\text{mina3max} = \text{mina3} - 1$
 $\text{minb3max} = \text{minb3} - 1$
 $\text{mindis4max} = \text{mindis4}$
 $\text{mina4max} = \text{mina4} - 1$
 $\text{minb4max} = \text{minb4} - 1$
 $\text{mindis5max} = \text{mindis5}$
 $\text{mina5max} = \text{mina5} - 1$
 $\text{minb5max} = \text{minb5} - 1$
 $\text{mindis6max} = \text{mindis6}$
 $\text{mina6max} = \text{mina6} - 1$
 $\text{minb6max} = \text{minb6} - 1$
 $\text{mindis7max} = \text{mindis7}$
 $\text{mina7max} = \text{mina7} - 1$
 $\text{minb7max} = \text{minb7} - 1$

End If

Cells(2482, 2).Value = iNPVmax
 Cells(2482, 3).Value = NPVmax
 Cells(2489, 2).Value = AEPmax
 Cells(2491, 2).Value = mindis1max
 Cells(2491, 3).Value = mina1max
 Cells(2491, 4).Value = minb1max
 Cells(2492, 2).Value = mindis2max
 Cells(2492, 3).Value = mina2max
 Cells(2492, 4).Value = minb2max
 Cells(2493, 2).Value = mindis3max
 Cells(2493, 3).Value = mina3max
 Cells(2493, 4).Value = minb3max
 Cells(2494, 2).Value = mindis4max
 Cells(2494, 3).Value = mina4max
 Cells(2494, 4).Value = minb4max

Cells(2495, 2).Value = mindis5max
 Cells(2495, 3).Value = mina5max
 Cells(2495, 4).Value = minb5max
 Cells(2496, 2).Value = mindis6max
 Cells(2496, 3).Value = mina6max
 Cells(2496, 4).Value = minb6max
 Cells(2497, 2).Value = mindis7max
 Cells(2497, 3).Value = mina7max
 Cells(2497, 4).Value = minb7max
 Cells(2498, 2).Value = SumIncomemax
 Cells(2499, 2).Value = SumOMCostmax
 Cells(2500, 2).Value = SumInvCostmax

Cells(i, 12).Value = SumAEP
 Cells(i, 13).Value = SumInvCost
 Cells(i, 14).Value = SumOMCost
 Cells(i, 15).Value = SumIncome
 Cells(i, 8).Value = NPV

For t = 1 To (Cells(10, 2).Value)

AvIncome = (Cells(71, t + 1).Value) * SumAEP

AvSumIncome = AvSumIncome + AvIncome

Next

AverageIncome = AvSumIncome / Cells(10, 2).Value

Tpb = (SumInvCost + SumAEP * Cells(45, 3).Value * Cells(10, 2).Value) / AverageIncome

Cells(i, 11).Value = Tpb

NPV1 = 9999999

r = 0

Do While (NPV1 >= 0)

SumIncome1 = 0

SumOMCost1 = 0

r = r + 0.001

For t = 1 To 20

Income1 = (Cells(71, t + 1).Value) * SumAEP * 1 / (1 + r) ^ t

SumIncome1 = SumIncome1 + Income1

OMCost1 = (Cells(45, 3).Value) * SumAEP * 1 / (1 + r) ^ t

SumOMCost1 = SumOMCost1 + OMCost1

```

Next
NPV1 = SumIncome1 - SumOMCost1 - SumInvCost
Cells(i, 9).Value = r
If IRRmax < r Then
    IRRmax = r
    iIRRmax = i
End If
Cells(2483, 2).Value = iIRRmax
Cells(2483, 3).Value = IRRmax
Loop

COE = (SumInvCost * annuity + SumAEP * Cells(45, 3).Value) / SumAEP
Cells(i, 10).Value = COE
If COEmin > COE Then
    COEmin = COE
    iCOEmin = i
End If
Cells(2484, 2).Value = iCOEmin
Cells(2484, 3).Value = COEmin
If Tpbmin > Tpb Then
    Tpbmin = Tpb
    iTpbmin = i
End If
Cells(2485, 2).Value = iTpbmin
Cells(2485, 3).Value = Tpbmin

Next

End Sub

```