KTH Electrical Engineering

EG2220 Power Generation, Environment and Markets
Compendium for future system design

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Contents

1 Introduction

Design of future power systems includes several tasks including power plant type, power plant location, transmission design, market design etc. In this compendium we will study only the design of the amounts and types of power plants and some issues which are of high relevance and importance. This means, e.g., that we will not discuss transmission expansion planning here. There are then many different alternatives both concerning the different types of units with different costs etc, but also many different ways of defining what a ”good” future power system is. Here we will analyze the impact from different types of assumptions on the resulting future power system.

2 Cost of power plants

The costs of power plants include the investments, the operation and maintenance. For already existing power plants the investments are already done, so even if the power plant is closed then these costs have to be paid anyhow.

Since a power plant has a certain life length, then a common way is to spread out the cost over the whole life, so there is a payment for the investment during each year in the future. This can be formulated as:

$$C_{yk} = \frac{C_k \cdot r_y}{1-(1-r_y)^L} \tag{1}$$

where

C_{yk} = Investment cost in [Euro/MW] per year for power plant of type k

C_k = Initial investment cost in [Euro/MW] for power plant of type k

r_y = Interest rate

L = Life length for power plant of type k

2.1 Costs during the construction time

It can take several years to construct some types of power plants. This then means that the owner has to spend money before there is some kind of income, which causes costs depending on the amount and interest rate. This then increases the cost, especially at high interest rates and long construction times. To estimate the total cost one takes the investment for each year and add the costs of the interest rate up to the actual start of the unit:

$$C_k = \sum_{i=1}^{I_k} C_{ki} \cdot (1+r_{yc})^i \tag{2}$$

where

I_k = Number of construction years for power plant k

C_{ki} = Investment cost i years before real start for power plant k

r_{yc} = Interest rate during the construction time.

Example 2.1 *In this example we will start to show the calculation of the total cost of a nuclear power plant according to data from [1]. The investment cost i 40000 SEK/kW. Using 9.5 Euro/SEK this results in 4211 Euro/kW. The construction is performed during six years with 10% at year -6, 15% at year -5, 15% at year -4, 20% at year -3, 20% at year -2 and 20% at year -1. The interest rate during the construction phase is 4%. Calculate the investment cost per kW. Also calculate an equivalent construction time assuming that the investments is spread out equally over a certain time and an interest rate of 4 or 6%.*

Solution to example 2.1: Using eq.2 results in

$$\begin{aligned} C_k &= 4211\left(0.10 \cdot 1.04^6 + 0.15 \cdot 1.04^5 + 0.15 \cdot 1.04^4 + 0.20 \cdot 1.04^3 + \right. \\ &+ \left. 0.20 \cdot 1.04^2 + 0.20 \cdot 1.04^1\right) = \\ &= 4774 \text{ Euro/kW} \end{aligned}$$

i.e. the cost increases with (4774/4211-1)=13.4% because of the construction time up to 6 years. If we instead assume that all investments are spread out from year -1 to year $(= -I_k)$ before the actual start and we assume an interest rate of r_{yc}%, then this specific year can be estimated from

$$\begin{aligned} C_k &= 4774 = 4211 \cdot \sum_{i=1}^{I_k} \frac{1}{I_k}\left[(1+r_{yc})^1 + (1+r_{yc})^2 + \ldots + (1+r_{yc})^{I_k}\right] \\ &\Rightarrow \\ C_k &= 4774 = 4211 \cdot \frac{1}{I_k}\frac{(1+r_{yc})^{I_k+1} - (1+r_{yc})}{r_{yc}} \\ I_k &= 5.3 \text{ years at } r_{yc} = 4\ \% \\ I_k &= 3.3 \text{ years at } r_{yc} = 6\ \% \end{aligned}$$

which shows that the assumption of 4% gives around the same amounts of years (5.3 instead of 6) as with the original, uneven, distribution of investments, while an interest rate of 6 % requires a much shorter construction time in order to get the same additional cost (3.3 years instead of 5.3).

End of example 2.1

2.2 Costs of reinvestments

For some types of power plants there may be a need of future reinvestments. These are then, economically, transferred to the first year, considering when they occur and the interest rate, in order to include the whole cost in the evaluation. This can be formulated as

$$C_{k1} = \frac{C_{fk}}{(1+r_y)^{F_k}} \tag{3}$$

where

C_{fk} = Future investment cost in [Euro/MW] for power plant of type k

C_{k1} = Future investment cost in [Euro/MW] transferred to an initial cost

F_k = Years ahead in the future when the reinvestment is needed for plant of type k

Example 2.2 *In this example we will continue the calculation of the total cost of a nuclear power plant according to data from [1]. According to this report, the reinvestment cost i 5000 SEK/kW and is needed after 25 years. Using 9.5 Euro/SEK this results in 526 Euro/kW. Calculate the corresponding initial investement cost per kW for this future investment assuming an interest rate of 6%.*

Solution to example 2.2: We can now apply eq. 3 which then results in

$$C_{k1} = \frac{C_{fk}}{(1+r_y)^{F_k}} = \frac{526}{(1+0.06)^25} = 122 \text{ Euro/kW}$$

As shown here a future costs, rather far in the future (25 years) has a comparatively low impact on the initial cost. For this specific case much lower than the extra cost caused by the interest rate during the construction time.

End of example 2.2

2.3 Fixed maintenance cost

In addition to this there may be fixed maintenance costs, in [Euro/MW,year] which have to be payed every year, no matter if the unit is used or not. This cost is then calculated for the whole period and transferred to the first year, considering the interest rate, in order to be considered together with all the other fixed costs:

$$C_{k2} = C_{myk} \cdot \sum_{j=1}^{L} \frac{1}{(1+r_y)^j} = C_{myk} \cdot \left(\frac{1}{r_y} - \frac{1}{r_y(1+r_y)^L} \right) \quad (4)$$

where

C_{k2} = Future maintenance costs in [Euro/MW] transferred to an initial cost

C_{myk} =Future maintenance costs during each year in [Euro/MW,year] for power plant of type k

There can also be a subsidy per MW for the initial investment, C_{ks} which then reduces the cost, i.e.

C_{ks} = Power plant subsidy[Euro/MW] for power plant of type k

Example 2.3 *In this example we will further continue the calculation of the total cost of a nuclear power plant according to data from [1]. In this report the fixed maintenance cost is 0 SEK/kW,year, but in this numerical example we assume that it is 2 SEK/kW,year. Using 9.5 Euro/SEK this results in 0.211 Euro/kW,year. Calculate the corresponding initial investment cost per kW for this future, yearly fixed maintenance cost and assuming an interest rate of 6%.*

Solution to example 2.3: We can now apply eq. 4 which then results in

$$C_{k2} = C_{myk} \cdot \left(\frac{1}{r_y} - \frac{1}{r_y(1+r_y)^L} \right) = 0.211 \cdot \left(\frac{1}{0.06} - \frac{1}{0.06(1+0.06)^{40}} \right) = 15.046 \text{ Euro/kW}$$

As shown here an assumed yearly cost of 0.211 Euro/kW,year has an impact on the investment cost. But the cost from [1] is 0 Euro/kW,year.

End of example 2.3

2.4 Total fixed cost

The total fixed cost per year can now be calculated as

$$C_{tyk} = \frac{(C_k + C_{k1} + C_{k2} + C_{ks}) \cdot r_y}{1 - (1 - r_y)^{-L}} \quad (5)$$

where

C_{tyk} = Total fixed cost in [Euro/MW] per year for power plant of type k

Example 2.4 *In this example we will continue the calculation of the total cost of a nuclear power plant according to data from [1]. Calculate the total investment cost, per year, assuming an interest rate of 6%. The life length of the power plant is 40 years and here we assume that there are no fixed maintenance costs per year. The interest rate during the construction time is assumed to be 4%.*

Solution to example 2.4: We can now apply eq. 5 which then results in

$$C_{tyk} = \frac{(C_k + C_{k1} + C_{k2} + C_{ks}) \cdot r_y}{1 - (1 - r_y)^{-L}} = \frac{(4774 + 122 + 0 + 0) \cdot 0.06}{1 - (1 + 0.06)^{-40}} = 325 \text{ Euro/kW, year}$$

This is then a fixed cost which has to be paid every year, independent of the amount of energy produced. How important it is for the cost per MWh depends on how many hours per year the power plant is producing.

End of example 2.4

2.5 Operation cost

In addition to the investment there are operating costs consisting of fuel costs, variable maintenance costs, emission costs and there may be also subsidies and/or different types of taxes. There can be emission costs for different types of emissions, e.g. CO2, NOX or SOX. Here only the ones from CO2 are considered in the expression. The result is then:

$$C_{emk} = C_{CO2} \cdot E_{k-CO2} \tag{6}$$
$$C_{Wk} = C_{emk} + C_{mk} + C_{fk} + C_{stk} \tag{7}$$

where

C_{emk} = Total emission cost [Euro/MWh] for power plant of type k

C_{Wk} = Total operation cost [Euro/MWh] for power plant of type k

C_{CO2} = Cost per ton of CO2 emissions

E_{k-CO2} = CO2 emissions from 1 MWh electricity production [ton CO2/MWh] for power plant of type k

C_{mk} = Maintenance cost [Euro/MWh] for power plant of type k

C_{fk} = Fuel cost to produce 1 MWh of electricity (i.e. the efficiency is included) [Euro/MWh] for power plant of type k

C_{stk} = Subsidy (negative) or tax (positive) for the production of 1 MWh of electricity in [Euro/MWh] for power plant of type k

2.6 Heat credit for a Combined Heat and Power plant

A combined heat and power plant, a CHP, produces both electric power and heat. When calculating the operation cost of the electricity production, then one also has to consider that there will be an income from the heat for each MWh of electricity production. Here we assume a simplified relation, so each MWh of electricity corresponds to a certain amount of heat production. We also, simplified, assume a 100% efficient use of the heat, so all primary energy that is not used for electricity, will result in usable heat production. The steps are then first to allocate all the costs to the electrical production, but then assign a *heat credit* to the operation cost of the electricity production. This then means that the operation cost of a CHP can be calculated as

$$C_{Whc-CHP-k} = \frac{1-\eta_{CHP}}{\eta_{CHP}} \cdot C_{thermal} \tag{8}$$

where

$C_{Whc-CHP-k}$ = Heat credit for CHP power plant of type k

η_{CHP} = Efficiency from fuel to electric power for CHP power plant of type k

$C_{thermal}$ = Heat credit as income from each MWh of heat production [Euro/MWh-heat]

Example 2.5 *In this example we will calculate the total opeation cost of a bio fuelled CHP power plant according to data from [2]. We then assume that the fuel cost is 21 Euro/MWh-heat, heat credit from the heat part to the electricity part is 34,1 [Euro/MWh-th], the electric efficiency is 28% and the maintenance cost is 2.2 Euro/MWh-el.*

Solution to example 2.5: We can combine eq. 8 with the other costs and the total operation cost becomes

$$C_{Wk} = C_{mk} + C_{fk} + C_{Whc-CHP-k} = 2.2 + \frac{21}{0.28} + \frac{1-0.28}{0.28} \cdot (-34.1) = -10.3 \text{ Euro/MWh}$$

For this example, this then becomes a negative operation cost which depends on that the heat credit is so high and assumed constant.

End of example 2.5

2.7 Total cost of a power plant

The total cost of a power plant is the sum of the investment cost and the operation cost. The operation cost is dependent on how many hours a certain power plant is used. If we now make a simplifed assumption that the power plant is either used at full capacity or not at all then we get the following formulation.

$$\begin{aligned} C_{tpk} &= \frac{T_p}{8760} C_{tyk} \cdot \hat{P}_k + C_{Wk} \cdot W_{pk} = \\ &= \frac{T_p}{8760} C_{tyk} \cdot \hat{P}_k + C_{Wk} \cdot \hat{P}_k \cdot T_{pk} \end{aligned} \tag{9}$$

where

T_p = Number of hours in the studied period p

$\hat{P}_k$ = Installed capacity in unit k

W_{pk} = Energy production in unit k during period p

T_{pk} = Operation time of unit k during period p

A wind or solar power plant has a variable production. This means that the yearly energy production has to consider the availability of wind or insolation. A common method is to either use the *capacity factor* or the *utilization time*. These are defined as:

$$f_{tk} = \frac{W_{pk}}{\hat{P}_k \cdot T_p} \tag{10}$$

$$T_{tpk} = \frac{W_{pk}}{\hat{P}_k} = f_{tk} \cdot T_p \tag{11}$$

where

f_{tk} = Capacity factor of source k during period p

T_{tpk} = Utilization time of source k during period p

The total cost of wind or solar power is then slightly modified by replacing the *operation time* (=number of hours the plant operates at installed capacity) with *utilization time* (=number of equivalent hours giving the same energy production as if the plant operates at installed capacity):

$$C_{tpk} = \frac{T_p}{8760} C_{tyk} \cdot \hat{P}_k + C_{Wk} \cdot \hat{P}_k \cdot T_{tpk} \tag{12}$$

Example 2.6 *In this example we will show the calculation of the total cost of a nuclear powe plant, per MWh, according to data from [1]. The investment cost are the same as in previous example. Assume a maintenance cost of 110 SEK/MWh, 9.5 SEK/Euro, a fuel cost of 43 SEK/MWh, a utilization time of 8300h/year and an availability of 95 %.*

Solution to example 2.6: Concerning the fixed part of the costs they can be calculated, per MWh, as

$$C_{fixed-per-MWh} = \frac{C_{tyk}}{8300 \cdot 0.95} = \frac{325000}{8300 \cdot 0.95} 41.2 \text{ Euro/MWh}$$

By adding the operation costs, the total cost per MWh becomes.

$$C_{total-cost-per-MWh} = C_{fixed-per-MWh} + \frac{1}{9.5}(43 + 110) = 41.2 + 16.1 = 57.3 \text{ Euro/MWh}$$

End of example 2.6

2.8 Actual data set-up of costs for new power plants

For the case studies below we have collected data from actual Swedish studies. The data for all power plants are from [2] (year 2016) except for coal power which is from [1] (year 2014). For Bio-CHP specific contacts have been taken. The data has been transferred to Euro using 9,5 SEK/Euro. The construction time has been adjusted since we here assume a constant expence for each yeat during the building time, while original data have more details concerning investments during each year. The aim has been to adjust the figures so the total production cost is close to the one of the original data. For wind and solar power, the maintenance costs have been largely changed from per MWh to per kW. It is unrealistic that the operation cost of wind power is more than 1 Euro-cent/kWh since that should mean that the wind power plants are shut down at a power price of, e.g., 0.9 Euro-cent/kWh, which is not the case. But the maintenance costs should not be neglected and is therefore changed to fixed instead of energy dependent. The collected data is shown in table 1. Concerning the different sources some general comments are found

		Investment			Mainte-nance	Reinvestment		Mainte-nance	Fuel	CO2
Nr	Source	Euro/ kW	Life Years	Build. time	Euro/ kW	Euro/ kW,year	in year	Euro/ MWh	Euro/ MWh	ton/ MWh
k		$C_k/$ 1000	L	I_k	$C_{myk}/$ 1000	$C_{k1}/$ 1000	F_k	C_{mk}	C_{fk}	E_{k-CO2}
1	Wind-land	1260	20	2	10	0	0	9	0	0
2	Wind-sea	2450	20	2	20	0	0	13	0	0
3	Solar PV	1050	25	0.1	10	100	15	0	0	0
4	Nuclear-1	4210	40	4.8	0	530	25	12	5	0
5	Nuclear-2	5410	40	4.8	0	530	25	12	5	0
6	Gas-OCGT	480	25	1	10	0	0	0	74	0,51
7	Gas-CC	740	25	1.8	10	0	0	3	51	0,35
8	Bio-cond.	3050	25	1	50	0	0	2	55	0
9	Coal-cond.	1680	25	3	30	0	0	3	21	0,71
10	Bio-CHP	4250	25	1	70	0	0	2	75	0
11	Bio-CHP	4250	40	1	70	0	0	2	75	0
11	Curtailments	0	0	0	0	0	0	0	2105	0

Table 1: Data for power plant investments

below. For details, there is a large amount of different types of estimations. These were the most recent estimations found (from 2014-2016):

1. **Nuclear-1:** These costs are from [2] refers to estimated costs for new nuclear power plants in Sweden. Assumed size in calculations is 1720 MW.
2. **Nuclear-2:** The costs are from [2] and refers to estimated costs for on-going new projects in Europe.

3. **Gas-OCGT:** The costs are for an Open Cycle Gas Turbine from [2], which is a plant type mainly used not so many hours per year. It has comparative low investment costs but higher operating costs. For CO2 emissions we assume use of natural gas, but the unit can also use bio gas. Assumed size in calculations is 150 MW.

4. **Gas-CCGT:** The costs are for a Combined Cycle Gas Turbine from [2], which has a higher efficiency than OCGT but also higher investment costs. For emissions we assume use of natural gas, but the unit can also use bio gas. Assumed size in calculations is 430 MW.

5. **Bio-cond.:** The costs are for a Condensing power plant using bio fuel from [2]. Assumed size in calculations is 150 MW. The plant type has rather high investment costs, so the main aim is for systems where it can be used many hours per year.

6. **Coal-cond.:** The costs are for a Condensing coal power plant and there were no data in [2], so instead we used [1] . The assumed investment is for a coal powder power plant with a size of 800 MW. The assumed coal price is around 80 Euro/ton.

7. **Wind-land:** The costs are for on-shore wind power from [2]. Assumed size in calculations is an on-shore wind park of 150 MW.

8. **Wind-sea:** The costs are for off-shore wind power from [2]. Assumed size in calculations is an off-shore wind park of 600 MW.

9. **Solar PV:** The costs are for a solar farm from [2]. Assumed size in calculations is 1 MW. It is assumed that for smaller sizes than this, the investment is slightly higher. It is assumed that one has to do a reinvestment after 15 years.

10. **Bio-CHP:** The costs are for a bio fuelled Combined Heat and Power plant [2]. Assumed size in calculations is 33 MW electricity. In comparison with the other types of power plants, this type also produces heat which is sold. Because of this there are several assumptions that have to be made concerning how much of the costs that have to be put on either the power part or the heat part.

11. **Curtailments:** These costs are more indirect costs. When there is not enough power plants then consumers have to be curtailed. There is normally a cost for them. Initially we here set the cost 20000 SEK/MWh which is the price that the Swedish System Operator introduces when consumers are curtailed. This cost then corresponds to 20000/9,5 =2105 Euro/MWh. This cost is different in different systems. The importance of this cost will be shown below.

If we then assume a certain interest rate, here 6%, and a certain amount of hours used per year, then the cost per MWh can be calculated. The results under these assumption are shown in table 2. However, as will be shown below the real cost, and the competitiveness between different power plants depends on how many hours per year that they are needed. Other cost estimations are, e.g., available from [3].

3 Studies of future power systems

Studies of future power system can be done in several different ways, and many combinations of assumptions are possible and also applied in reality. Some fundamental factors are shown in table 3. These are:

Set-up: One common set-up is *Green field studies* where it is assumed that the future system is built up from the beginning. It may also refer to a future situation which is so far in the future so all power plants can be assumed to be new. An alternative set-up is *Additional investments* where it is assumed that a certain amounts of today investments still exists. The difference between these two types is whether all (in *Green field*) or not all (in *Additional investments*) investment costs are included in the analysis.

Nr	Source	Interest rate	Hour/ Years	Investment Euro/kW	Investment Euro/MWh	Operation Euro/MWh	Total cost Euro/MWh
k		r_y	W_k/P_k	$C_{k1}/1000$	C_{yk}/W_k	C_{Wk}	C_{tk}
1	Wind-land	6%	2900	1491	45	9	54
2	Wind-sea	6%	3700	2813	66	13	79
3	Solar PV	6%	970	1239	100	0	100
4	Nuclear-1	6%	7885	4847	41	16	57
5	Nuclear-2	6%	7885	6193	52	16	68
6	Gas-OCGT	6%	98	571	456	74	529
7	Gas-CC	6%	8134	886	9	53	62
8	Bio-cond.	6%	7680	3848	39	58	97
9	Coal-cond.	6%	7760	2159	22	24	46
0	Bio-CHP	6%	4800	5365	87	-10	77
11	Bio-CHP-2	6%	5760	5531	64	-10	54
12	Curtailments	6%	-	0	0	2105	2105

Table 2: Examples of total costs for new power plants

Objective: One common objective is *Minimum cost* where the aim of the study is to select the combination of future sources which provides the lowest total cost for the society. One can hear, e.g., include CO2 costs or not. Another possible objective is then *market driven.* This is then based on the assumption that a power plant is **NOT** built if the costs for it is not covered by the income. There can then be different set-ups of markets including, e.g., energy-only market (only income from produced energy) or different kinds of capacity payments.

Requirements: There can also be different combinations of system requirements. These can be, e.g., *Reliability*, where there is a restriction concerning how many hours of the year when the capacity is not enough to cover the demand, i.e., causing curtailments. Common requirements also include *Share of renewables* or *maximum CO_2 emissions* where, e.g., EU or different countries have goals to be considered.

Variables: A question is then what the aim of the study is. The aim then controls what is classified as *variables*, i.e., what kind of results is the output of the results. Some common results, i.e., classified as variables before the study, are, e.g., *MW in each power plant*, *taxes or subsidies* or *CO2 prices*. *MW in each power plant* is the result in most studies, but if one, e.g., has *Reliability* as a requirement, then one has to make this possible by using some kind of extra payment or market design, i.e., a certain set-up of *subsidies.* If one has a restriction on *Share of renewables* or *maximum CO_2 emissions*, and at the same time has an assumption on *market driven*, then there must be a possibility to achive this. A possibility is then to, e.g., study the possibility of using *subsidies* or *CO2 prices*, to make this possible. I.e., to use *subsidies* or *CO2 prices* as *variables.* In fundamental economic analysis it can be assumed that new units are not built if they are not profitable. If we assume a 100% reliable power system (LOLP=0.0), then the last unit in merit order, with the highest marginal cost, needs an extra payment above this level in order to be profitable. This means that this *marginal* can be treated as a variable.

So there are a lot of possible combinations of the different issues shown in table 3. Some are common and some are not. The different combinations will have a large impact on the results, so for any study the assumptions made (= combinations in table 3) are essential for the type of conclusions one can draw from a study. One can, e.g., not state that a certain issue is a "result" (reliability, share of renewables etc) if this is handled as an **input** in the study. In addition to the issues in table 3, a large amounts of assumption can be made concerning different types of parameters.

Below some possible combinations of issues in table 3 will be shown for a certain system. All studies are based on the Excel-program *Future-power-system-design.xlsx.*

Set-up: - Green field study - Additional investments	**Objective:** - Minimum cost - Market driven
Requirements: - Reliability - Share of renewables - Maximum CO2 emissions	**Variables:** - MW in each power plant - taxes or subsidies - CO2 prices

Table 3: Important factors in studies for future power systems

3.1 Basic system set-up

Below there will be several numerical examples in order to show the real impact of changing some assumption or parameters. A challenge is then that real systems are very large with interconnections with neighboring systems and if outages are also to be considered, then the result is very extensive model requirements. Here we will only study a comparatively small systems. Important restrictions here include: fixed demand (not price dependent), one area with no transmission limits, no uncertainties in forecasts, no hydro power and any other types of storage and no requirements on reserves, and 100 % reliable power plants. The benefit is that it is rather easy to understand the impact from changing some assumptions or parameters. These include development of costs, interest rates, costs for curtailments, fuel prices etc.

The applied set-up in the Excel program, possible changes in this program and reality are shown in table 4.

	Applied set-up	Possible modifications	Real Systems
Studied period	200 hours from 3 representative periods in a year	change studied days	Several years
Sources	Nuclear, coal, gas, wind, bio, solar, only one cost/type	some more sources days for wind/solar flex. demand as a source	All sources with different costs
Transmission	One area with no restrictions	-	Many areas
Availability	Thermal power: 100% wind/solar: specific days	wind and solar days can be changed	All details can be considered
Uncertainties	not considered	-	can be considered

Table 4: Set-up of studied system

Example 3.1 *This is the base case example. The demand is total Swedish demand with the following period start days: 2015-01-22 (total of 60 days), 2015-06-29 (total of 40 days), 2015-04-10 (total of 100 days). Peak load is 21335 MW in hour 16. The installed capacities are Wind power: 8000 MW, Nuclear: 3000 MW, Gas-OCGT: 2000 MW, Gas-CC: 5000 MW, Coal power: 10000 MW. The investement and operation costs of the different units are found in table 1. Wind power production is real Swedish production for the same period as for the demand but scaled to 8000 MW. The CO2 cost is assumed to be 10 Euro/ton. For this system: Calculate operation cost, reliability, power price and profit for the different sources assuming marginal cost pricing, and optimal use of existing resources which means loading according to marginal costs.*

Solution to example 3.1: The studied period and resulting output is shown in figure 1. Also prices for each hour, with the assumption of marginal cost pricing, are shown. The economic data for the different souces, assuming a *green field* study with all costs considered, is found in table 1. With production as in figure 1, the results are shown in table 5. Perfect competition leading to "Marginal cost pricing" is

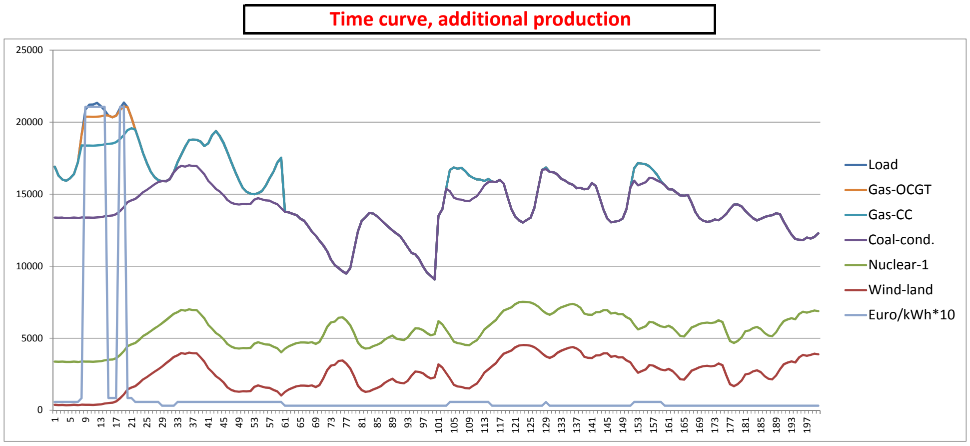


Figure 1: Power production for example 3.1. The production per hour for each source is the difference between the respective line and the one below, i.e., *additional production*. The base case refers to total Swedish demand with the following period start days: 2015-01-22 (total of 60 hours), 2015-06-29 (total of 40 hours), 2015-04-10 (total of 100 hours). Peak load is 21335 MW in hour16 and mean price is 123.5 Euro/MWh.

assumed for the operation and pricing and an energy-only market for the income for the power plant owners. This means that the units are loaded in merit order according to marginal operation cost. This then results in lowest possible operation cost with the existing power plants. It is also assumed that the power price is set by the operation cost of the marginal unit, and the only income for the generating units is the income from the power price.

The here applied solution method, i.e., no restriction on ramps from one hour to the next, means that one will get exactly the same result if wind and load are respresented with duration curves. This is now shown in figure 3. From figure 3 one can, e.g., identify that nuclear power (second lowest operation cost)

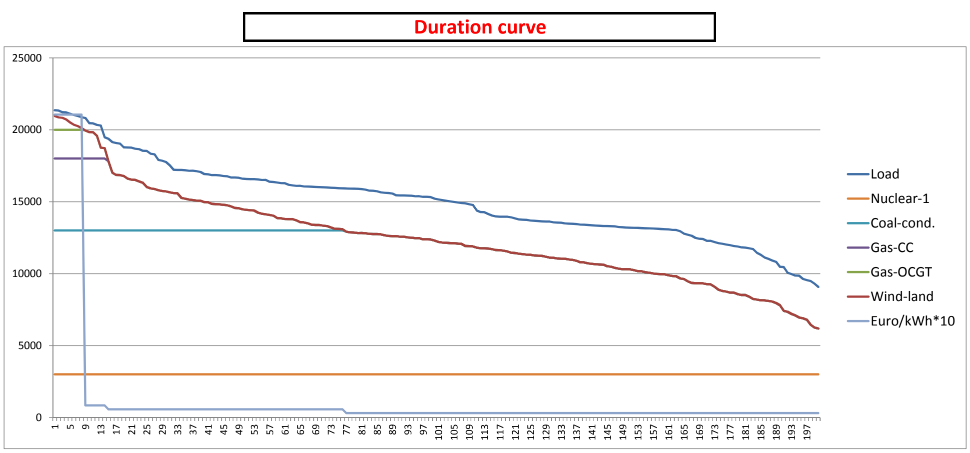


Figure 2: Power production for example 3.1. Same system as in figure 1 but here shown with load duration curves. Wind power has the lowest operation cost, but is withdrawn from the load in order to show the net-load durationg curve: [load - wind power]

is used all the time followed by coal condensing power (third lowest operation cost). In the figure it is also shown that wind+nuclear+coal is not enough during 76 hours of the week, i.e., the next source is needed during 76 hours of the week. It is also shown that the unit with the highest operation cost, Gas-OCGT, can cover all load up to 20000 MW which means that during 8 hours in the period there is not enough capacity, i.e., curtailments are needed. This means that the LOLP=8/200=4 %. The amount of operating hours for each power plant is also found in table 5.

Mean price:	123,4	€ / MWh		Total cost	Profit	CO2	Utilization time
Source:	MW	MWh	MWh [%]	kEuro	kEuro/MWh	tons	hours
Wind-land	8000	504498	16,8%	28255	-0,2	0	200
Nuclear-1	3000	600000	19,9%	31728	70,5	0	200
Gas-OCGT	2000	24684	0,8%	3983	1231,0	12485	14
Gas-CC	5000	183473	6,1%	18360	407,0	64000	76
Coal-cond.	10000	1691135	56,2%	90733	86,6	1200412	200
Curtailments	956	4631	0,2%	9750	0,0	0	8
Total:	28956	3008421	100,0%	182808	1794,8	1276898	

Table 5: Power production for example 3.1 with production as in figure 1

End of example 3.1

Some comments can now be stated around this first base case:

- This is **not** a result of any optimizations. There are several other combinations of MW per source, which result in lower costs.
- This in **not** a 100 % reliable power system since there are some curtailments. The curtailments can be up to 956 MW which is 4.5% of the peak load. However only 0.2 % of all energy demand is curtailed (i.e. EENS=0.2 %). There are curtailments during 8 hours so the LOLP = 8/200= 4 %.
- All power plants, except wind power, are profitable.
- The price is assumed to be set by the marginal cost of the system, and the mean price becomes rather high since it goes up to the curtailment price, 2105.3 Euro/MWh, during the 8 hours of curtailments.
- The amount of renewable energy in this system is around 17% (energy) but from capacity point of view (share of installed capacity) it is 8000/28000 = 28.6 %.
- There is a certain amount of CO2 emissions in the system (1,28 Mton for the studied period).
- Many of the data and results here can mainly be seen as a reference case for later studies.

We will now slightly modify the base case in example 3.1. The modification is to modify the load and the wind power production in order to make the load duration curve linear. The reason is that one then can make simplified calculations but still study the general challenges between different set-ups according to table 3.

Example 3.2 *The original demand is same the total Swedish demand as in example 3.1, but it is here modified during each hour in order to get a linear load duration curve. The installed capacities are also the same as in example 3.1: Wind power: 8000 MW, Nuclear: 3000 MW, Gas-OCGT: 2000 MW, Gas-CC: 5000 MW, Coal power: 10000 MW. Also wind power production is slightly modified in order to get a linear net load duration curve. For this system: Calculate operation cost, reliability, power price and profit for the different sources assuming marginal cost pricing.*

Solution to example 3.2: The studied period and resulting output is shown in figure 1. For this case the linearization of the load and wind power results in that the LDC and NLDC can be described as

$$LDC_{example-3.2}(t) = 21360 - (t-1) \cdot 61 \text{ MWh/h} \tag{13}$$
$$NLDC_{example-3.2}(t) = 20960 - (t-1) \cdot 74 \text{ MWh/h} \tag{14}$$

where

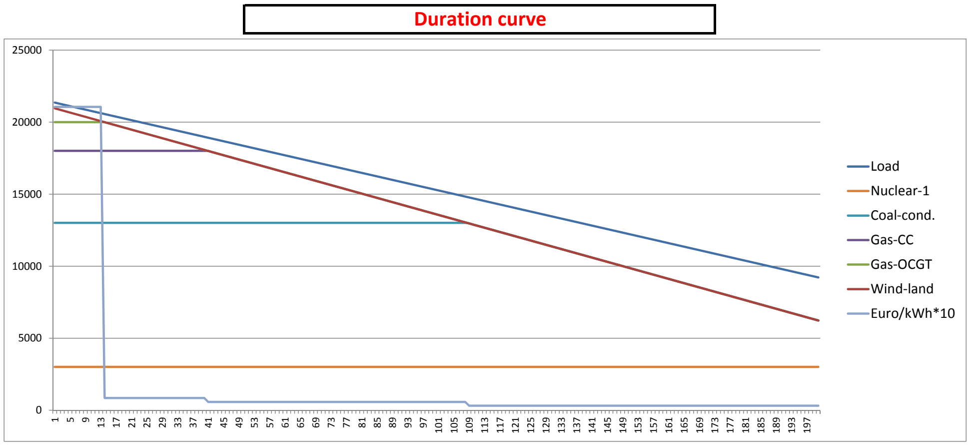


Figure 3: Power production for example 3.2 with linearized load duration curve (LDC) and net load duration curve (NLDC)

$LDC(t)$ = Load Duration Curve for hour t, i.e., the load is at least on this level during t hours during the studied period.

$NLDC(t)$ = Net Load Duration Curve for hour t, i.e., the net load=[load - wind power]=need for other sources, is at least on this level during t hours during the studied period.

As an example one can then easily calculate the total demand energy and wind energy as

$$LDC_{energy} = 21360 \cdot 200 - \frac{200 \cdot 16 \cdot 199}{2} = 3058100 \text{ MWh} \tag{15}$$

$$NLDC_{energy} = 20960 \cdot 200 - \frac{200 \cdot 74 \cdot 199}{2} = 2719400 \text{ MWh} \tag{16}$$

$$Wind_{energy} = LDC_{energy} - NLDC_{energy} = 3058100 - 2719400 = 338700 \text{ MWh} \tag{17}$$

Since the load and wind power are slightly changed, then the production in the other sources will also change compared to table 5. The new results are shown in table 6.

Mean price:	181,0	€ / MWh		Total cost	Profit	CO2
Source:	MW	MWh	MWh [%]	kEuro	kEuro/MWh	tons
Wind-land	8000	338700	11,1%	26771	-4,0	0
Nuclear-1	3000	600000	19,6%	31728	128,1	0
Gas-OCGT	2000	53972	1,8%	6289	938,5	27299
Gas-CC	5000	371428	12,1%	29062	345,1	129564
Coal-cond.	10000	1687292	55,2%	90614	155,1	1197684
Curtailments	960	6708	0,2%	14122	0,0	0
Total:	28960	3058100	100,0%	198586	1562,8	1354547

Table 6: Power production for example 3.2

End of example 3.2

3.2 Total cost minimization

We now have a base-case with six different possible sources as shown in figure 1 and table 5. They are On shore wind power, Nuclear, Gas-OCGT, Gas-CC, and Coal Condensing. If production is not enough, then there will be curtailments, but these are formally handled as high cost production, with no investement costs. An important issue concerning Curtailments is the applied cost for these. A common interpretation of these costs is the so-called VOLL (Value of Lost Load). If this is set extremely high, then curtailments will not happen since any power production has a lower cost. And if it is too low, then the amount of curtailments will be high. Here we will now assume that we design a future system using minimization of total cost.

Example 3.3 *Assume we have a system with data as in table 1. We assume an interest rate of 6%, the cost of curtailment, VOLL, is set to 2105 Euro/MWh and the cost of CO2 is 10 Euro/ton, which is slightly higher than current price (5,8 Euro/ton in October 2016). For this case: Assume a Green field study, apply cost minimization and calculate operation cost, reliability, power price and profit for the different sources assuming marginal cost pricing.*

Solution to example 3.3: In general an optimal solution (not considering wind power) can be identified in the following way. We start by analyzing the total cost for the thermal sources Gas-OCGT, Nuclear, Gas-OCGT, Coal and curtailments using eq. 9. We calculate the cost per MW:

$$C_{tpk}/\hat{P}_k = \frac{200}{8760} C_{tyk} + C_{Wk} \cdot T_{pk} \tag{18}$$

We can then draw the curve for each power source and curtailments, i.e., the total production per MW as a function of the utilization time. The result is shown in figure 4.

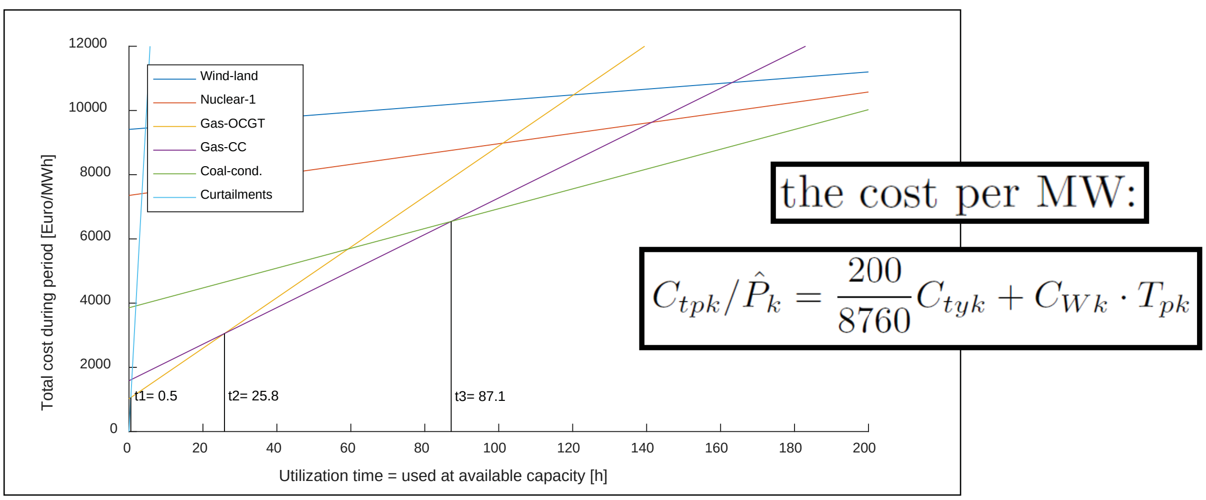


Figure 4: Importance of utilization time for power plant selection

The numbered points in figure 4 are intersection points, i.e., when eq. 18 gives the same value for two curves. With curves k and j this then gives the utilization time T_{jk}:

$$\begin{aligned} C_{tpk}/\hat{P}_k &= C_{tpj}/\hat{P}_j = \frac{200}{8760} C_{tyk} + C_{Wk} \cdot T_{jk} = \frac{200}{8760} C_{tyj} + C_{Wj} \cdot T_{jk} \\ &\Rightarrow \\ T_{jk} &= \frac{200}{8760} \frac{C_{tyk} - C_{tyj}}{C_{Wj} - C_{Wk}} \end{aligned} \tag{19}$$

The figure shows important issues concerning the different sources:

- At zero utilization time, i.e., at the y-axis, one can identify the capatal cost for the 200 hour period for the different sources.

- There is a faster increase of the cost/MW for units with high operation costs.
- For utilization 0.5 hours curtailments is the most efficient solution with the here assumed costs.
- The lowest envelope shows which source to be used for which utilization time. If the utilization time is < 25.8 hours but longer than 0.5 hours then Gas-OCGT is the unit with lowest cost. At utilization time from 25.8-87.1 hours Gas-CC is the low-cost unit and for higher utilization time coal power is the source with lowest cost.
- Nuclear power is too costly to be profitable.

The optimal amount of solar and wind power is a more challenging issue and it is not possible to use this kind of simplified calculations. The optimization can be formulated as:

$$\begin{aligned} \min C_T &= \sum_{k=1}^{6} \frac{200}{8760} C_{tyk} \cdot \hat{P}_k + C_{Wk} \cdot W_k \\ \text{considering} & \\ \hat{P}_k &\geq 0 \\ \hat{P}_6 &= \max \left(D_i - \sum_{k=1}^{5} P_k(i) \right) \end{aligned} \tag{20}$$

where

C_T = total cost

$\hat{P}_k$ = installed capacity in unit k. Unit 6 = Curtailments and the maximum curtailment is the maximu needed in one hour.

$P_k(i)$ = production in unit k at hour i

W_k = energy production in unit k during the studied 200 hours. The units are firsts ordered from lowest to highest operating cost. One then a) start with the unit with lowest cost, unit $j = 1$. b) This unit produces as much as possible during each hour. For wind power "as much as possible" is the scaled production for the available time series of wind power production. For the other units it is the installed capacity. For all units one cannot produced more than available room between scheduled units with lower operation cost and the demand. c) $j = j + 1$ continue with next unit until all units are considered.

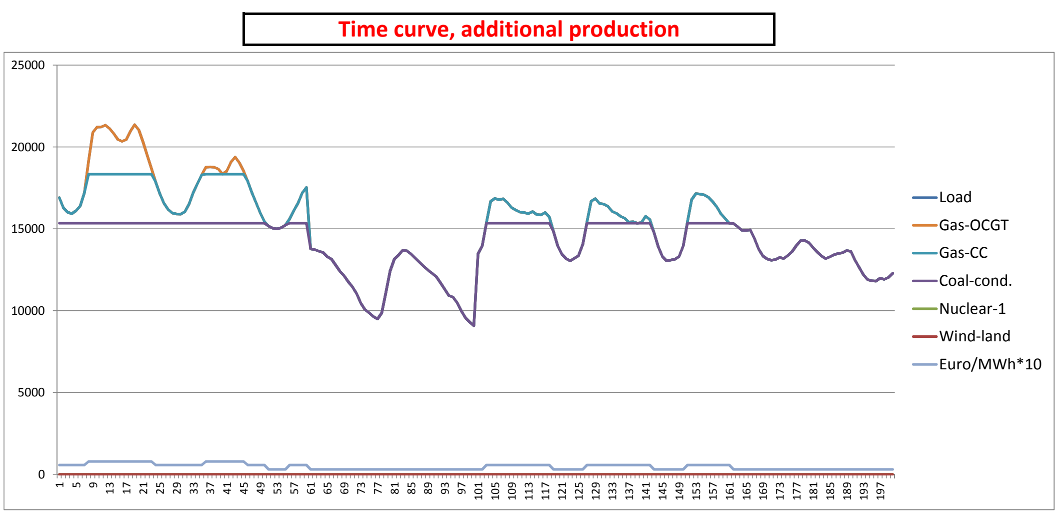


Figure 5: Power production at cost minimization, VOLL=2105 Euro/MWh, CO2: 10 Euro/ton

Mean price:	46,5	€ / MWh		Total cost	Profit	CO2	Utilization time
Source:	MW	MWh	MWh [%]	kEuro	kEuro/MWh	tons	hours
Wind-land	0	0	0,0%	0	-	0	0
Nuclear-1	0	0	0,0%	0	-	0	0
Gas-OCGT	3023	39848	1,3%	6220	-77,3	20155	26
Gas-CC	3002	150073	5,0%	13296	-20,3	52350	98
Coal-cond.	15339	2818500	93,7%	146101	-4,0	2000645	200
Curtailments	0	0	0,0%	0	-	0	0
Total:	21364	3008422	100,0%	165617	-101,7	2073150	

Table 7: Power production costs at cost minimization and production as in figure 5

The result is now shown in figure 5. With production as in figure 5, the results are shown in table 7. For this kind of problem one can use the load duration curve, LDC, and base the analysis on this instead. This means that one sorts the data in figure 5, and the result is shown in 6. In the figure it is shown that nuclear power is not used, and coal power is used up to load levels that occure around 68 hours during the studied period. This corresponds to the level 66.9 hours identified in figure 4. Some comments can

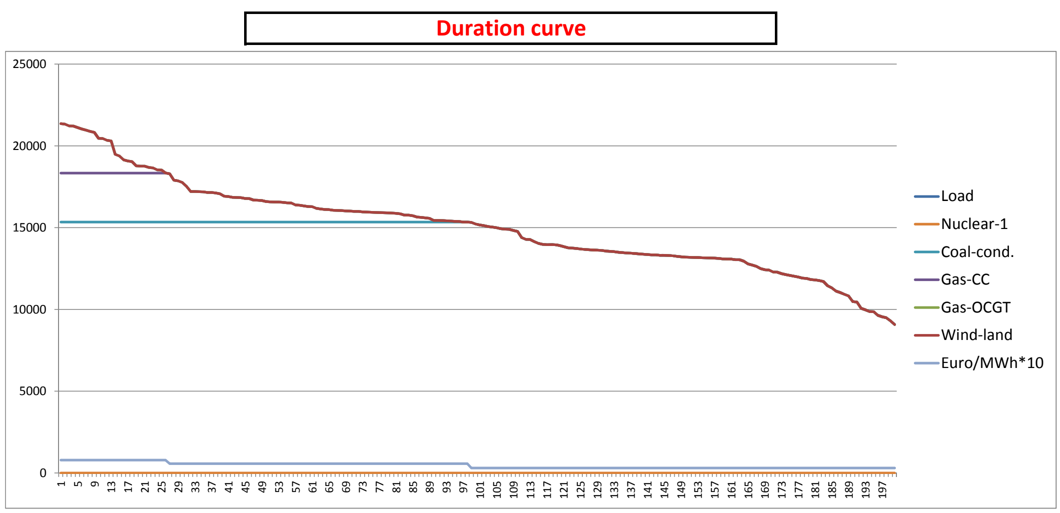


Figure 6: LDC-description of figure 5

now be stated around this case by comparing table 7 with table 5:

- This is now a result cost minimization. The total cost has decreased from168 MEuro to 152 MEuro, i.e., a decrease of 9 %.
- There are (nearly) only fossil fuelled units selected. This depends on a combination of low investment and operation costs as well as low CO2 cost.
- There is a small amount of nuclear power which is mainly a result of numerical inaccuracies in the calculation method.
- This in now a 100 % reliable power system since there are no curtailments.
- No power plants are profitable. An important reason is that there are no curtailments, so the price is never on the VOLL level.
- The amount of renewable energy in this system is zero since wind power has higher costs than fossil fuelled plants.
- There is a certain amount of CO2 emissions in the system (2,09 Mton for the studied period). This is an increase with 64 % compared with the base case.

3.3 Reliability margins

In the optimization one then also have to consider that the amount of curtailments has to be lower than a certain target. There are then slightly different alternatives. One is to limit the maximum amount of curtailment ($\hat{P}_6$) while another method is to maximize the amount of hours with curtailment. It can be noted that if one reduces the amount of hours with curtailment, then this also reduces the amount of hours with high prices, since it is assumed that power price is set by marginal cost. This can be formulated as:

$$\min C_T = \sum_{k=1}^{6} \frac{200}{8760} C_{tyk} \cdot \hat{P}_k + C_{Wk} \cdot W_k \tag{21}$$

considering

$$\begin{aligned} \hat{P}_k &\geq 0 \\ \hat{P}_6 &= \max\left(D_i - \sum_{k=1}^{5} P_k(i)\right) \\ \hat{P}_6 &\leq Curtail_{max} = \text{Maximum amount of curtailment} \end{aligned} \tag{22}$$

Example 3.4 *This example is based on the linearized demand and wind power from example 3.2. There are then two cases: A - no wind power and B - with wind power. In this simpolified example there are two other sources: Coal power and OCGT. And if the sources do not produce enough, then there will be curtailments. The curtailment costs are here, for illustrative reasons, decreased with a factor of 10. The costs of the different sources are summarized in table 8.*

Nr	Source	C_{tyk} [Euro/MW/period]	C_{wk} [Euro/MWh]	E_{k-CO2} [ton/MWh]	T_{kj} [h]
1	Coal	3855.9	30.85	0.71	59.23
2	OCGT	1019.6	78.74	0.51	7.74
3	Curtailments	0	210.53	-	-

Table 8: Costs for sources in example 3.4. T_{kj} is the minimal utilization time for the source, calculated with eq. 19. At shorter utilization time, the next source has a lower cost.

The questions for this system are:

a) Assume a cost min90imizing approach for both case A and case B. What is the difference in LOLP?

b) What is the change in coal power and energy production when moving from case A to case B.

c) How much will the CO2 emission change from case A to case B assuming cost minimization

d) Assume a requirement of LOLP is maximum 0.1%. Which is then the needed price for the last OCGT in order to get this in case B.

e) Assume a requirement of LOLP is maximum 0.1%. Which is then the needed capacity payment for OCGT in order to get this in case B and not allowing higher prices than during curtailments, i.e., 210.53 Euro/MWh

Solution to example 3.4: The studied period and resulting output is shown in figure 7.

a) The LOLP corresponds to the number of curtailment hours. This is for both cases = T_{23}= 7.74 hours, corresponding to 7.74/200=3.87 %.

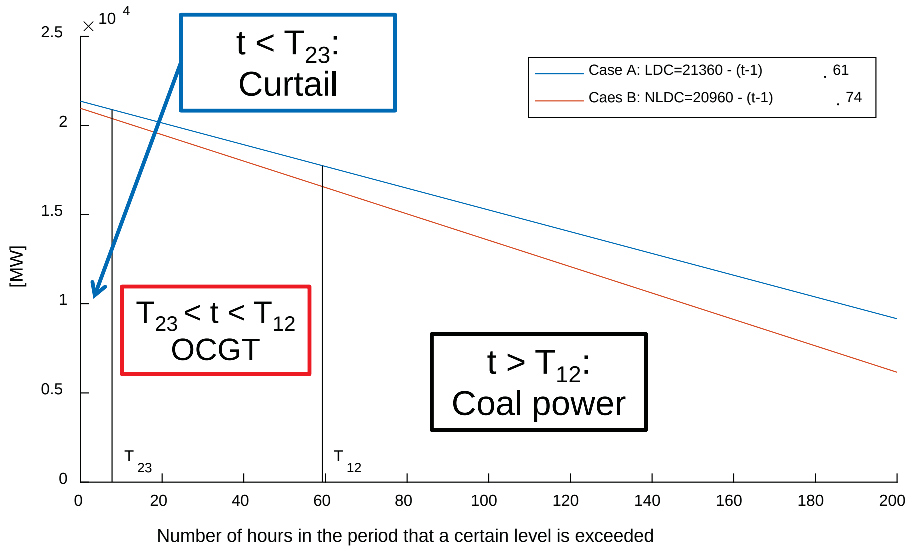


Figure 7: Linearized load duration curve (LDC) and net load duration curve (NLDC) for example 3.4

b) The amount of coal power can be identified from the known utilization time which is at least 59.23 hours. For case A this correponds to loads below $21360 - 58.23 \cdot 61$=17750 MW and for case B it corresponds to $20960 - 58.23 \cdot 74$=16651 MW. The decrease in coal power is then 1099 MW. The energy production is shown in figure 8. The energy production is then calculated as the corresponding area, i.e., a sum of one triangle and two rectangles:

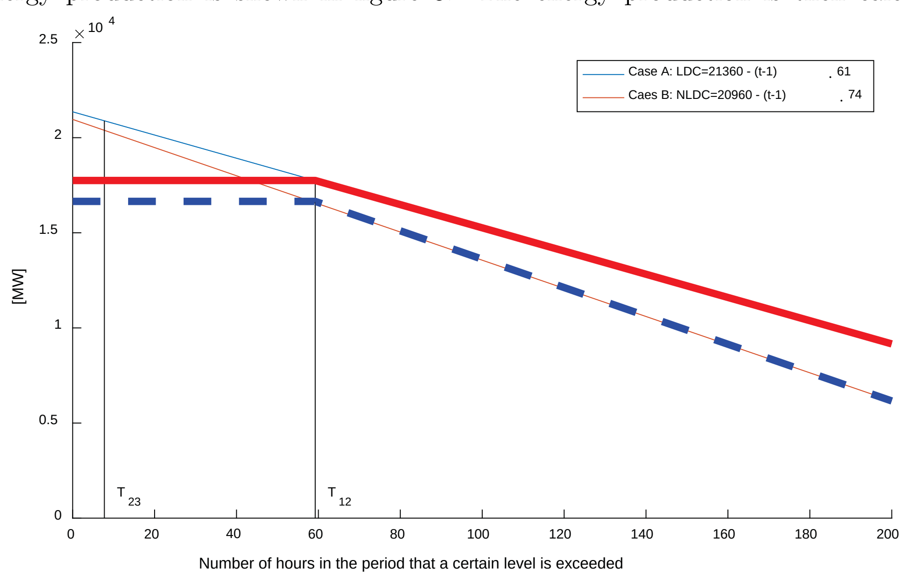


Figure 8: The coal power energy production for example 3.4. Case A: Coal energy is the area below the thick red curve. Case B: Coal energy is the area bolw the thick, dashed blue curve.

$$
\begin{aligned}
Min_{LDC} &= 21360 - 199 \cdot 61 = 9221 \text{ MW} \\
Min_{NLDC} &= 20960 - 199 \cdot 74 = 6234 \text{ MW} \\
W_{coal}(A) &= 59.23 \cdot 17750 + (200 - 59.23) \cdot 9221 + \frac{1}{2}(200 - 59.23) \cdot 9221 = 2949.7 \text{ GWh} \\
W_{coal}(B) &= 59.23 \cdot 16651 + (200 - 59.23) \cdot 6234 + \frac{1}{2}(200 - 59.23) \cdot 6234 = 2597.0 \text{ GWh}
\end{aligned}
$$

c) First the energy production in the OCGT has to be calculated. This is done in the corresponding way as for the coal power, i.e., the area between the corresponding curve for OCGT and the one for coal power:

$$
\begin{aligned}
MW_{OCGT}(A) &= 21360 - 7.74 \cdot 61 - 17750 = 3192.3 \text{ MW} \\
MW_{OCGT}(B) &= 20960 - 7.74 \cdot 74 - 16651 = 3810.2 \text{ MW} \\
W_{OCGT}(A) &= 7.74 \cdot 3192.3 + \frac{1}{2}(59.23 - 7.74) \cdot 3192.3 = 106.88 \text{ GWh} \\
W_{OCGT}(B) &= 7.74 \cdot 3810.2 + \frac{1}{2}(200 - 59.23) \cdot 3810.2 = 127.57 \text{ GWh}
\end{aligned}
$$

What is shown here is that the amount of both capacity and energy production, in the OCGT:s, is increased when a system with wind power and minium costs is designed. Coal power is decreased with 1099 MW while OCGT increases with 618 MW. Changes of CO2 emissions now become

$$
\begin{aligned}
CO2(A) &= 2949.7 \cdot 10^3 \cdot 0.71 + 106.88 \cdot 10^3 \cdot 0.51 = 2.149 \text{ Mton CO2} \\
CO2(B) &= 2597.0 \cdot 10^3 \cdot 0.71 + 127.57 \cdot 10^3 \cdot 0.51 = 1.909 \text{ Mton CO2} \\
CO2(A) - CO2(B) &= 0.240 \text{ Mton CO2}
\end{aligned}
$$

which then means a decrease of 0.240/2.149 = 11 %. From the calculations in example 3.2 this is then a result of introducing 338700 MWh in a system with a total demand of 3058100 MWh, i.e., 11 %.

d) The aim is a requirement of LOLP is maximum 0.1% and we evaluate this for case B. In the "cost minimizing case" we have curtailments during 7.74 hours out of 200, i.e., an LOLP of 3.87 %. An LOLP of 0.1% corresponds to $0.001 \cdot 200 = 0.2$ hours during this week. The cost for the last MW of OCGT is then the sum of the investment cost for 200 hours but only paid during the 0.2 hours of use, plus the operating cost. The price must then be on this level in order to finance the last MW:

$$
\text{Needed price} = \frac{1019.6}{0.2} + 78.74 = 5097.8 + 78.74 = 5176.5 \text{ Euro/MWh}
$$

e) The last MW of OCGT is only used during the 0.2 hours with curtailments and the price is then 210.53 Euro/MWh. The income during these 0.2 hours is then $0.2 \cdot 210.53 = 42.11$ Euro. The operation cost during the 0.2 hours is $0.2 \cdot 78.74 = 15.75$ Euro. This means that the last MW of capacity is paid with 42.11-15.75= 26.36 Euro. But the cost for the last MW is 1019.6 Euro. So the capacity payment must be 1019.6-26.36=993.2 Euro/MW.

End of example 3.4

4 Manual for Excel Program

Here it is described how to change data and run the Excel-program *Future-System-design* which is used to produce all results in this compendium. First the original data are shown in Figure 9. These data is mainly from the Swedish report [2] but for coal condensing units the data are from [1]. The interest rate for the construction time is here set to 4 % but it can be changed. The investment cost is assume to be spread equally over the construction time and this time is shown for each source in the table.This value is selected in order to get the correct investment cost from the corresponding report. In reality there are different assumptions for each source concerning how much is invested during different periods. But here this is simplified to just get one number. All data can be changed in this figure. The data are in SEK, as in the original reports, but for changing to Euro an exchange rate of 9.5 SEK/Euro is assumed. The main idea of the program is to NOT change the data here (except for construction time and construction interest rate), since this can be done more rational in another place.

To run a specific case the main selection for the sources is shown in figure 10. Here six different sources can be selected. On the left column **Nr** one can select six possible sources from figure 9. All blue data

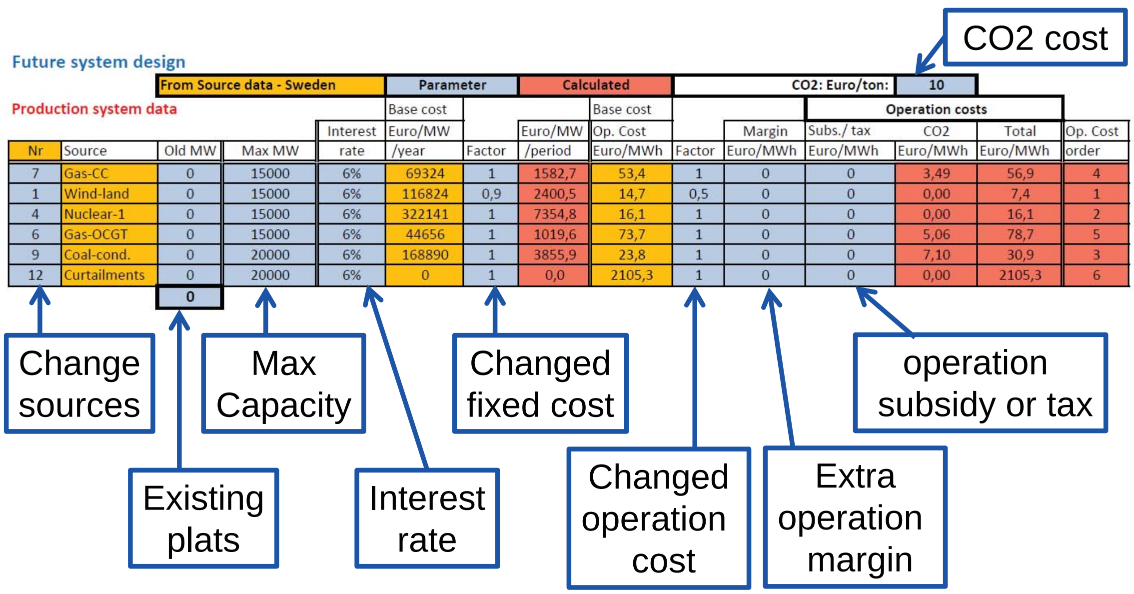
Cost estimations: A: Promeroria

Data from source B: Elforsk

Construction interest rate: 4%

Nr	Source	Source	Investment SEK/kWel	years	Built Time years	DoU SEK/kW,year	Reinvestment SEK/kWel	in year	Operation Maintenance SEK/MWh	Fuel SEK/MWh-heat	Efficiency percent	Fuel kr/MWh-el	Heat paym. SEK/MWh	CO2 ton/MWh-el
1	Wind-land	A	12000	20	2				140					
2	Wind-sea	A	23000	20	2				180					
3	Solar PV	A	10000	25	1		970	15	90					
4	Nuclear-1	A	40000	40	4,8	0	5000	25	110			43		0
5	Nuclear-2	A	51400	40	4,8	0	5000	25	110			43		0
6	Gas-OCGT	A	4600	25	1	50	0	0	0	280	40%	700		0,51
7	Gas-CC	A	7000	25	1,8	80	0	0	25	280	58%	483		0,35
8	Bio-cond.	A	29000	25	1	500	0	0	21	200	38%	526		0,00
9	Coal-cond.	B	16000	25	3	250	0	0	30	90	46%	196		0,71
10	Bio-CHP	A	40400	25	2	700			21	200	38%	526	-324	
11	Bio-CHP-2	Fort.	29000	40	1				21	200	38%	526	-324	
12	Curtailments		0	1	1	0	0	0	0	0	0	20000		0

Figure 9: Original data set-up. Sheet: *Source-data Sweden*


Future system design

Production system data

From Source data - Sweden | Parameter | Calculated | CO2: Euro/ton: 10

Nr	Source	Old MW	Max MW	Interest rate	Base cost Euro/MW /year	Factor	Euro/MW /period	Base cost Op. Cost Euro/MWh	Factor	Margin Euro/MWh	Operation costs Subs./ tax Euro/MWh	Operation costs CO2 Euro/MWh	Operation costs Total Euro/MWh	Op. Cost order
7	Gas-CC	0	15000	6%	69324	1	1582,7	53,4	1	0	0	3,49	56,9	4
1	Wind-land	0	15000	6%	116824	0,9	2400,5	14,7	0,5	0	0	0,00	7,4	1
4	Nuclear-1	0	15000	6%	322141	1	7354,8	16,1	1	0	0	0,00	16,1	2
6	Gas-OCGT	0	15000	6%	44656	1	1019,6	73,7	1	0	0	5,06	78,7	5
9	Coal-cond.	0	20000	6%	168890	1	3855,9	23,8	1	0	0	7,10	30,9	3
12	Curtailments	0	20000	6%	0	1	0,0	2105,3	1	0	0	0,00	2105,3	6
		0												

Figure 10: Production source data selection. Sheet: *System design*

can be changed. The column **Old MW** refers to that this is a fixed amount that cannot be changed. It will later be shown that the program can design a system, but the column **Max MW** then states the maximum limit for this selection. The **Interest rate** can then be selected individually for the different sources. Concerning the investment cost this is taken from figure 9, but one can assume a change of this by adding a factor. As shown in the figure it is here assumed that wind power in the studied future situation has become 10% cheaper. The Investment cost for the source is then scaled in the column **Euro/MW/period** with the factor 200/8760 in order to consider that the economic calculations is done for 200 hours and not for the whole year.

Also the operation cost is taken from figure 9 and also these can be changed in the following column **Factor**. The column **Margin** refers to that a source can be assumed to bid at a higher price than marginal cost for the pricing in the system. It is this increase that can be set by changin the Margin. It is also possible to set as assumed CO2 cost and one can also assume a certain tax or subsidy per MWh for each selected source.

For the print out one have some different options. These are shown in figure 11. The possible selections are the numbers in the blue cells. For the load one can select *original* but one can also select *simplified*. This option means that the loads are slightly modified in order to get a linear load duration function. When the simplified option is selected, then the parameters of the load duration curve (LDC) is shown on the bottom to the left. One has the same option for wind power, assuming that wind power is included

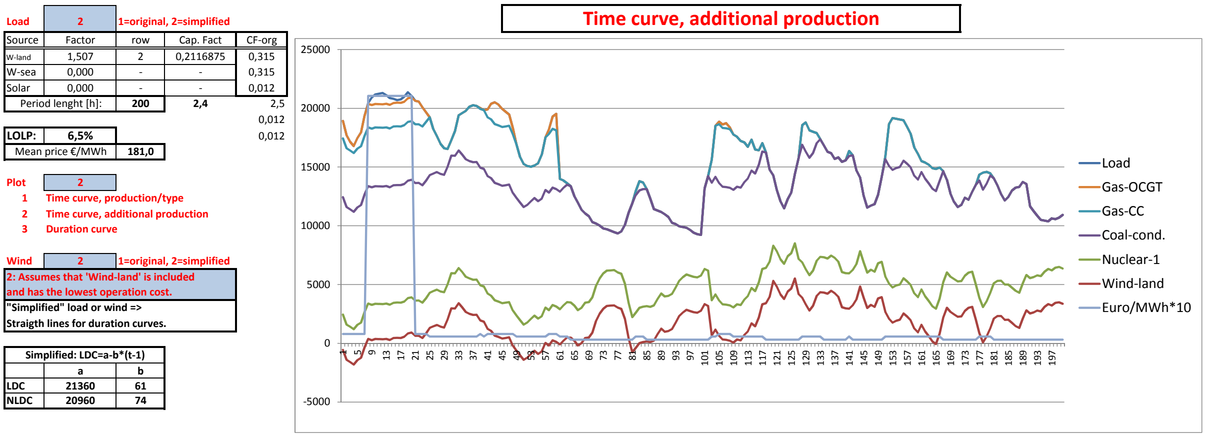


Figure 11: Print out selection. Sheet: *System design*

as a source and that it has the lowest operation cost of the included sources. When *simplified* is selected for wind power, then also the Net Load Duration Curve (NLDC) becomes linear by modifying the wind production data for each hour. The parameters for the NLDC is shown at the bottom to the left.

For printing of curves it is possible to select duration curve, a time curve per source, or time curve where the sources are added upon each other in merit order.

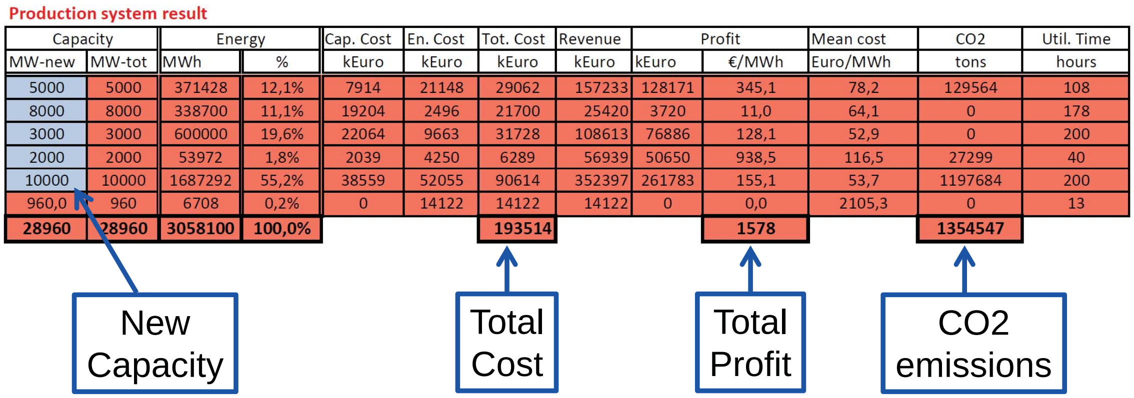
To the right in the sheet *System design* it is possible to select the load, wind and solar power period to be included. This part of the sheet is shown in figure 12. The total number of hours is 200 in the calculation. First the time step can be selected. This means that one can select to use every hour, every second hour or every thirs hour starting on a a certain date. The 200 hours are divided into three periods. The start of each period can be selected as well as the length of the two firsts periods. The length of the third period is calculated since the sum has to be 200.

	Hour step:	1	1, 2 or 3 is possible	
Per.	Load day	Wind day	Solar day	Nr of hours
1	22	22	15	60
2	180	180	23	40
3	100	100	48	100
1	2015-01-22	2015-01-22	2015-01-15	
2	2015-06-29	2015-06-29	2015-01-23	
3	2015-04-10	2015-04-10	2015-02-17	

Figure 12: Time period selection. Sheet: *System design*

The final results are shown in figure 13. In the column **MW-new** one can select the new installed capacity of the first five sources. The size of the last one is selected in order to fulfill the load in all situations. One then have to consider that if one of the sources is wind power or solar power, then it may happen that it is not wind or sun enough to meat the peak load. So the sum of the capacity of all units is then large than the peak demand. The **MW-new** can either be selected manually (just change the numbers) or one can let the program optimize the best selection (see 4.1). The column **MW-tot** is then the sum of of column **MW-old** and **MW-new**. The difference is that **MW-old** are assumed to be already existing, so the investment costs are then not included in the economic calculations. But for **MW-new** these are included. For a so-called *green field study* then the **MW-old** are assumed to be zero.

The column **Energy-MWh** is then calculated in the following way. For each hour one add the units according to increasing operational costs until the load is covered. For wind and solar power there is a



Production system result

Capacity		Energy		Cap. Cost	En. Cost	Tot. Cost	Revenue	Profit		Mean cost	CO2	Util. Time
MW-new	MW-tot	MWh	%	kEuro	kEuro	kEuro	kEuro	kEuro	€/MWh	Euro/MWh	tons	hours
5000	5000	371428	12,1%	7914	21148	29062	157233	128171	345,1	78,2	129564	108
8000	8000	338700	11,1%	19204	2496	21700	25420	3720	11,0	64,1	0	178
3000	3000	600000	19,6%	22064	9663	31728	108613	76886	128,1	52,9	0	200
2000	2000	53972	1,8%	2039	4250	6289	56939	50650	938,5	116,5	27299	40
10000	10000	1687292	55,2%	38559	52055	90614	352397	261783	155,1	53,7	1197684	200
960,0	960	6708	0,2%	0	14122	14122	14122	0	0,0	2105,3	0	13
28960	**28960**	**3058100**	**100,0%**			**193514**			**1578**		**1354547**	

Figure 13: Final results. Sheet: *System design*

historical series available and this is then scaled in order to correspond to the total amount of MW in the column **MW-tot**. The other sources are assumed to always have to total capacity (from **MW-tot**) available.The total energy is then the sum of the energy in each source during the 200 hours. In the next column, **Energy %**, the percentage of energy contribution during the studied period is calculated.

4.1 To get an optimal system for the future

In Excel there is a possibility to automatically change the numbers in some cells in order to obtain some objective. This is done by using the using the function **Solver** (in Swedish **Problemlösaren**) which is found by selecting **Data**. Sometimes this is not shown in the Data menu and then it has to be installed/activated. Then go to the question mark at the top to the right in Excel and make a search on Solver and follow the instructions of how to install it.

When one use **Solver** the picture as in Figure 14 is shown

Objective: On the top of the figure one find the objective (”målsättning” in Swedish). The example in the figure is cell W12, i.e., the total cost. Below ”Min” is selected. This set-up means that the objective is to minimize the content of cell W12, i.e., to minimize the total cost.

Variables: The next selection is what is allowed to change, i.e., ”variables”. This is the next row, and there the variables Q6:Q10 are selected. This means, in reality the total installed capacity in all the different sources. The curtailments are NOT included, since these are calculated as a function of total installed capacity, peak load and amount of solar and wind power during the peak load.

Constraints: The next selection are the limits and constraints (”Begränsningar” in Swedish). Here the following are selected Q6:Q10 $\leq$ D6:D10. This means that the selected amount of **new** MW for each source is limited to a certain amount using the data in cells D6:D10. This constraint is needed since there must be an upper bound set for all varaibles to be handled by the solver. The total amount of MW for a source is the already existing amount in column C plus the new capacity (which is selected using Solver) in column Q. It is also stated that R11 $\leq$ D11 which is a limit on the curtailment. There is also a limit stating R6:R10 $\leq$ D6:D10. This is a limit for the total amount of capacity, i.e., the sum of already existing capacity (column C) and new capacity (column Q).

Solution: The optimization problem is then to minimize the objective by changing the variables and considering the constraints. This is done by pressing button **Solve** (”Lös” in Swedish). For the problems formulated here this is, however, not always trivial. The real problem is non-linear and also non-convex. This means that one have to select solvers which can solve this kind of problems. One can select ”Non-

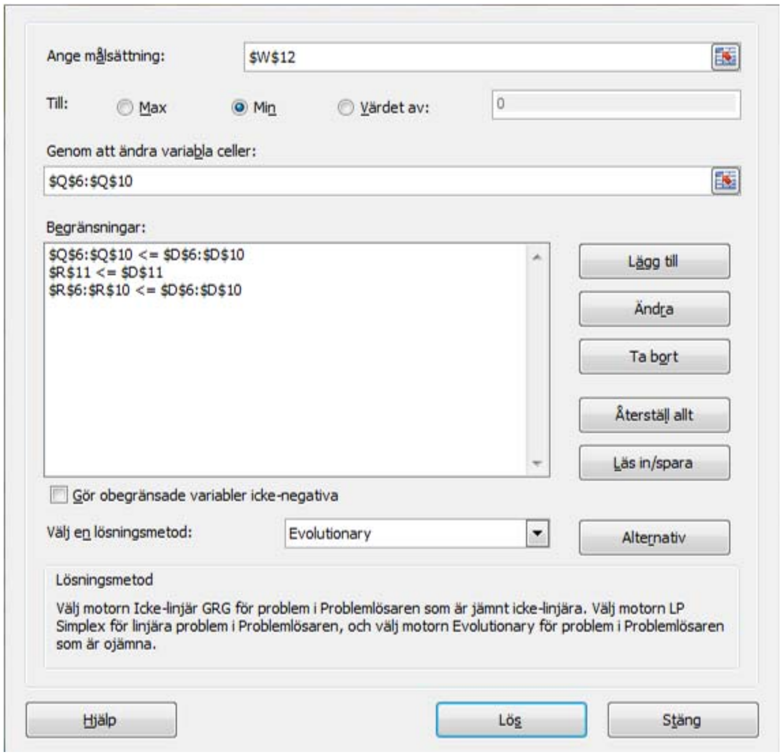


Figure 14: The **Solver** window

linear Gradient method" or "Evolutionary method". The "Non-linear Gradient method" is rather fast, but it only finds a local optimimum. The "Evolutionary method" is not so fast (takes some minutes), but can find better solutions. The best way is to start with "Evolutionary method" and then fine tune the answer with "Non-linear Gradient method". The task is to find the best solution, and if a "new" solution is "better" than the previous one, one can identify by studying the objective value.

This showed the basic set-up for optimization, i.e., to find a good solution. This can then be modified, and examples are shown in table 9.

Optimization aim	Modification in **Solver**
Green field study	Column C should be empty
Fixed amount of a source	Do not include it as a variable or set existing amount = limit
Reliability requirements	set a **constraint** on curtailments < a value or LOLP in B21 < than a value
Maximum CO2 emissions	set a **constraint** on these in cell AB12 < a value
Minimum share of renewables	set a **constraint** on these sum of these in T6:T10 > a value

Table 9: Examples of how to perform different optimizations

References

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