SYSTEM AND INTEGRATION COSTS IN WIND AND SOLAR ENERGY

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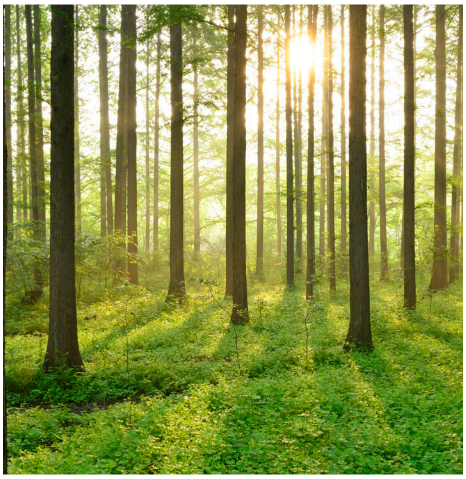


VINDFORSK


Energiforsk

System and Integration Costs in Wind and Solar Energy

Definitions and analysis

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Foreword

This report has been initiated by Vindforsk and its steering group to highlight the complexity of the future electricity system and to clarify the connections between the different costs related to increasing amount of wind energy.

Possible ways to measure costs and benefits that arise in electricity generation systems with high proportions of weather-dependent power is as important as it is complex to analyze and develop knowledge about. To allow efficient decisions, it is essential to start by defining what is meant by, for example, system costs or integration costs and which aspects affect the cost calculations discussed.

For the wind energy sector, it is particularly important to reduce misunderstandings and incorrect conclusions linked to economic consequences of the large-scale wind power expansion we are now facing in Sweden. With this report, Vindforsk hopes to contribute to a more informed discussion and less uncertainty about the costs of integrating high shares wind power into Sweden's electricity network.

The results and conclusions of this project has been conducted by Lennart Söder, Professor in electric power systems at KTH.

We hope you find the results interesting.

Göran Dalén
Chairman of Vindforsk

Sammanfattning

Det finns såväl i Sverige som internationellt en frågeställning kring "*integrationskostnaden för vindkraft*". Men denna avses storleken på de övriga kostnader som tillkommer i ett kraftsystem när mängden vindkraft ökar. Det överordnade syftet med att diskutera denna typ av kostnader är att man vill få till en samhällsekonomisk och hållbar elförsörjning och då måste alla konsekvenser av olika försörjningsalternativ beaktas, inte enbart vad en viss anläggning kostar. Men frågan är betydligt mer komplicerad än att man enbart kan ange en generell kostnad i form av ett visst antal öre/kWh. Syftet med denna rapport är att gå igenom utmaningarna med att uppskatta de totala kostnaderna för att dimensionera ett elsystem samt att specifikt studera idéer som finns för hur man skulle kunna uppskatta en integrationskostnad.

Rapporten är uppdelad i två delar. Den första delen avser uppskattning av "*systemkostnaden*" dvs de totala kostnaderna för ett specifikt elsystem. Det behövs elproduktion och elnät, men även rimliga marginaler samt utrustning som gör att man kontinuerligt kan hålla en systembalans mellan produktion och konsumtion. Centralt är här vilket system man studerar, systemgränser, handel med utlandet, antagande om flexibilitet, hur systemet är optimerat etc. Rapporten går även igenom termen "*värdefaktor*" vilken avser skillnaden mellan ett kraftverks genomsnittliga intäkt och det genomsnittliga elpriset. Denna blir olika för olika produktionsslag beroende på länken mellan systemets marginal-kostnad och produktionsprofilen.

Den andra delen avser uppskattning/beräkning av en "*integrationskostnad*". Denna typ av kostnad finns för, t ex, elvärme, elbilar, vindkraft eller solkraft där man förutom själva anläggningen behöver mer utrustning för att hela elsystemet ska fungera. En fundamental utmaning är att definiera denna kostnad och framför allt hur man skulle kunna allokera kostnaden till en specifik teknologi. Det finns en stor mängd valmöjligheter för framtiden för såväl produktionssidan, konsumtionssidan, systemuppbyggnad och marknadsmodeller vilket komplicerar tillämpningen. Den grundläggande funktionen i ett kraftsystem är att för varje kilowattimme konsumtion behövs ett elnät som kan överföra denna konsumtion från en produktionskälla som producerar den efterfrågade energin, och vice versa.

Såväl systemkostnad, värdefaktor som integrationskostnad kan variera mycket beroende på olika antaganden om systemuppbyggnad. I rapporten finns flera numeriska exempel där syftet är att visa inte bara kvalitativa utan även kvantitativa resultat för dessa kostnader vid olika antaganden om systemuppbyggnad. I dessa visas att såväl värdefaktorn som integrationskostnaden kan variera med mer än en faktor 10 beroende på olika antaganden. Dvs mycket mer än olika antaganden om kostnaden för själva produktionsanläggningarna.

Slutsatser

Om systemkostnad: Hur denna beräknas har stor betydelse för storleken på såväl värdefaktorn som integrationskostnaden. När man jämför olika system kan man anta, t ex, att systemet är utbyggt optimalt för ett visst scenario eller att utbyggnaden bygger på marknadens antaganden om vad man tror kommer hända i framtiden. Man kan också anta olika nivåer på koldioxidskatter, krav på leveranssäkerhet, produktionskostnader, metoder och teknologi för att upprätthålla en kontinuerlig balans i systemet, eller möjlig framtida flexibilitet. Det vill säga antagandena styr resultatet.

Om värdefaktor: Denna kallas ibland även profil-kostnad. Denna innebär att man i ett system med mycket stora mängder vindkraft, i genomsnitt får lägre betalt än vattenkraft, eftersom vattenkraften styrs till att producera vid högre priser medan vindkraften producerar när det blåser. Denna kostnad inkluderas inte i själva anläggningskostnaden, men för en marknad som den svenska där intäkterna huvudsakligen kommer från ett varierande elpris per timme, beaktas den av investerarna. Det går inte att ansätta ett ”korrekt värde” då det helt beror på systemet och olika antaganden om hela systemuppbyggnaden.

Om integrationskostnad: Olika systemuppbyggnader kostar olika, men ”*integrationskostnaden*” är, till skillnad mot värdefaktorn, inte entydigt definierad. Storleken på denna kan variera mycket beroende på definition och antaganden om hur ett framtida system är dimensionerat.

Slutsatsen från den här gjorda analysen är att:

- Det är mycket relevant att jämföra olika scenarier för framtiden för att på detta sätt få en uppfattning om såväl total systemkostnad som värdefaktorn för olika kraftslag. Och även för konsumenter är det centralt att förstå vad just de kommer få för elpris beroende på flexibilitet etc. För närvarande, september 2021, händer t ex mycket, där konsumtionsprognoser har ändrats radikalt bara på det senaste året. Främst gällande vätgasanvändning, vilket med de nya antaganden kraftigt ändrar såväl behovet av mer elproduktion som tillgänglig flexibilitet. Så nya scenarier bör kontinuerligt studeras och jämföras.

- Det centrala är att ha en marknad som i så stor utsträckning som möjligt reflekterar systemets totala kostnader och intäkter. Detta ger incitament till marknadens aktörer till rätt investeringar. Mycket av detta är implementerat i Sverige jämfört med många andra länder. Men självklart behövs detta utvecklas vidare speciellt för ett system med signifikant mer variabel elproduktion och stora flexibilitetsmöjligheter på konsumtionssidan.

Summary

The future power system will certainly be different in many ways compared to today power system. IEA states, e.g., in their Net-Zero report (IEA - International Energy Agency, 2021) that "*Two-thirds of total energy supply in 2050 is from wind, solar, bioenergy, geothermal and hydro energy. Solar becomes the largest source, accounting for one-fifth of energy supplies. Solar PV capacity increases 20-fold between now and 2050, and wind power 11-fold.*" In order to evaluate different possible scenarios it is important to have an estimation of the total cost for the different expansion alternatives. One basic measure is then the Levelized Cost of Energy – LCOE, which refers to the cost of the power plants, but this is only a part of the total cost. Not only power plants are needed, but also a grid and there are many possibilities of how to manage the needed continuous balance between production and consumption including different flexibility options in the consumption.

In this report, we have studied the possibilities and challenges of estimating *total system costs* for a future power system and also the definition and estimation of *integration costs*. The overall purpose of discussing these type of costs is the need to achieve a socio-economic and sustainable electricity supply where all consequences of different supply alternatives must be taken into account, not just the cost of a certain power plant costs. However, the question is much more complicated than to only specify a general cost in the form of a certain number of additional cents/kWh. The purpose of this report is to review the challenges of estimating the total costs of sizing an electrical system, and to specifically study existing ideas for how to estimate an *integration cost*.

Both system costs and integration costs, can vary greatly depending on different assumptions about system structure. The report contains several numerical examples where the purpose is to show not only qualitative but also quantitative results for these costs for various assumptions about system structure.

Total system costs

Total system costs consist of production cost + grid costs + balancing costs (including costs to obtain a continuous and stable supply) + outage costs. For a specific system set-up, it should be possible to estimate these costs, which can be further divided into investment costs and operation costs. However, there are several challenges that have to be considered to estimate these costs, which is not always clear in different reports. These include:

- It is important to apply clear definitions so each cost is considered exactly one time. One example is costs of "*electrical losses*" which is an operation cost for a grid owner, but at the same time an operation cost of power plants.
- Do not mix "*market values/costs*" which are "*marginal values/costs*" with physical costs. One cannot directly use "*marginal costs*" if the aim is to estimate "*total cost*".
- Be clear concerning the system set-up and the aim of the system study. One can, e.g., optimize the total system set-up for 2040 or any other year, but this is

then based on that one already now takes all decisions concerning which system to go for. Technically this is possible, but it is based on the assumption the we know the technical/economical/ environmental development and what will happen up to this horizontal year in the studied area as well as in neighboring systems with which one can assume future trading. An alternative is to instead consider the real world where investment decisions are taken, based on uncertain forecasts for the future, and margins have to be kept. These two approaches both have their pros and cons, but they will certainly lead to different system set-ups.

Value factor

Based on a simulation of the total cost of a power system there is a possibility to estimate the "*value factor*", sometimes also called "*profile cost*" for any power source or consumer. This factor states the difference between obtained mean price for the source/consumer and the yearly mean price. If, e.g., there is a large amount of wind power, then there will be lower prices at high amount of wind power, which means that the yearly mean revenue for the wind power owner will be lower than the yearly mean price. However:

- The "*value factor*" is not easily linked to any profit. One source can have a "*negative value factor*" but is still more profitable than another source with a positive value factor. I.e. the market may choose to invest in a certain source even if this source has a significantly lower value factor.
- The "*value factor*" is very different depending on the system set-up.
- It is **not** possible to state "*this is the value factor for this source*". It totally depends on the system set-up. It is only possible to define the value factor for a certain case study.
- The "*value factor*" is sometimes denoted "*profile cost*", but it is not a cost. It is the difference between the yearly mean price and the power price weighted according to a production profile. Power prices are marginal costs in energy only markets. This means that the "*value factor*" is the difference between two estimations of marginal costs, and thereby linked to the *value* of a certain source.
- When there is an energy only market, then the "*value factor*" is already internalized for the investors, since it reflects the price the source owner will get. I.e. the investors consider this when they take investment decisions.

Integration cost

An "*integration cost*" can be seen as the cost for the whole system change when there is a change in the system. One example is that when we connect an Electric Vehicle, the cost is not only the LCOE for a power plant that produces the needed energy per year for the vehicle, but also costs for grids, grid losses and the continuous balancing. This example illustrates the challenge of allocation of integration costs. Is it the demand or a production source that causes an "*integration cost*"? The current challenge in many countries is a strong electrification trend on the consumption side, with different flexibility options as well as several alternatives on the production side.

The "*integration cost*" is in a published paper and some reports defined as the change in costs in the remaining power system when source A is changed to source B or any other change in a power system. One part of the "*integration cost"* is the so-called "*profile cost*" which refers to the changed operation costs in the remaining power system. However:

- The "*integration cost*" is not easily linked to any profit. One source can have a "*high integration cost*" but is still more profitable than another source with a lower one.
- The need, applied flexibility and technology use on the consumer side depends on variability and the total cost of electricity, i.e. there is a link between load flexibility and production system investments.
- The "*integration cost*" is very different depending on the system set-up.
- It is **<u>not</u>** possible to state "*this is the integration cost for this source*". It totally depends on the system set-up.
- The "*value factor*" above is at least clearly defined, it can be calculated in a certain scenario. However the "*profile cost*" (not the same as the "*value factor*") has **<u>not</u>** a clear definition. One of the challenges is that the LCOE is not a constant, since the utilization time of a certain source depends on the amount and type of the other sources, i.e. it depends on the system set-up. So one question is which LCOE one should use since this is one of the basis for the estimation of the profile cost. As shown in a numerical example, this can have a large impact.
- Another issue with "*profile cost*" is that it is not possible to allocate this cost to a certain source. The reason is that it depends on in which order one considers possible changes in the system. If we, e.g., have wind power and storage, then wind power integration cost is lower if we first integrate the storage. In reality all investments are linked since we only have one system.

Conclusions

In order to illustrate the quantitative impact on value factor and integration costs, some simple numerical examples have been included. It is not claimed that these refers to reality in any specific system. The reason why they are shown, is that they clearly illustrate that different system set-ups have large impacts on the numerical results.

Concerning value factor

As an illustration, the "*value factor*" has been estimated with different assumptions for a certain system. The results are summarized in Table 1:

Table 1 Results for the "value factor", and "profit" for some different examples in chapter 4 [EUR/MWh]. Extraction from Table 4

Case	1	2a	2c	2d	2f	3b	4a	4b
Wind value factor	-0,95	-1,00	-1,56	-0,74	-9,21	-15,44	-14,55	-21,48
Nuclear value factor	0,00	0,00	0,00	0,00	4,69	18,66	0,00	23,91
Wind profit	43,13	56,41	17,15	42,25	20,13	1,74	48,42	3,52
Nuclear profit	17,88	31,22	-7,48	16,79	3,76	-7,61	36,78	3,81

The table shows the value factor for the two sources wind power and nuclear power for different system set-ups. It also shows the total profit for the different sources (all units in each group seen as one source) where it is assumed that the production is sold to the market where the price is set by the marginal cost.

As shown in Table 1 the "*value factor*" can change more than a factor 10 depending on the system set-up. It clearly illustrates that the "*value factor*" depends on system set-up. It is not easy to see a clear link between the "*value factor*" and the market profit for the different sources.

Concerning profile cost

To allocate specific costs to market participants and consumers is not a clear concept. Under commodity markets: energy, reserves, and capacity, are allocated according to matching demand and supply, price formation and market rules. Other regulated costs, network and policy costs, are allocated through tariff design principles. How to allocate costs through tariffs etc., is a combination of incentivizing, cost-reflecting, fair treatment of larger groups and practical reasons. As an illustration the "*profile cost*" has been estimated by using a method presented in a paper (Ueckerdt, Hirth, Luderer, & Edenhofer, 2013) and in some reports (OECD/NEA, 2019). However, the definition in the paper is not clear when there are several changes and use of data, and different assumptions can be used for one specific scenario of a certain system. The results for a test system are summarized in Table 2:

Profile cost is here defined as the changed operation costs in "the remaining power system" when a source is added to the system. A fundamental issue is then, e.g., if the new source replaces another source and if so in which way. A question is also in which order one consider the changes since there can be many changes in the system.

Table 2 Results for the "profile cost" for some different examples in chapter 4 [EUR/MWh]. It is for ONE specific system, but with different methods for how to allocate the "profile cost" to different sources.

Case	6b-6c	6e-6g	6h-6j	6k-6m
"Profile cost" for 1500 MW offshore wind power	0.48	2.35	5.10	0.35
"Profile cost" for 3500 MW onshore wind power	0.32	3.82	2.64	0.28
"Profile cost" for 3000 MW of storage	-2.49	-7.61	-7.61	-8.35

As shown in Table 2 the "*profile cost*" can change rather much (a factor 10) depending on the method for how to estimate it. The table shows the results for one specific system set-up. It is the change in the detailed definition of the "*profile cost*" that here illustrates the problem of how to clearly define a "*profile cost*". The "*Total cost*" is the same for the different set-ups, but the challenge is that the method for how to allocate the "*profile cost*" to different technologies is not possible to clearly define.

Final comments

There are certainly many challenges concerning how to design the future power system. There are many options concerning grid design, market set-up, production alternatives, flexibility investments, use of available flexibility etc. In order to analyze the consequences for prices, emissions, reliability etc, it is common to study different scenarios for the future. There are then some comments around how to show the results from these different scenarios.

a) "*Integration cost*" is, as shown in some examples, very different depending on system assumptions and definitions. It always origin from a comparison between two (or more) system simulations. The results should be discussed as differences in cost/prices/emissions/reliability between these two specific scenarios. It then becomes obvious that there are assumptions (and modelling choices) dictating the results. The term "*Integration cost*" can only be specified for a single set-up of system studies and is only relevant for that specific set-up.

b) The term "*profile cost*" is in different studies used with two definitions for different phenomena, so it is important to specify which one that one refers to. **One definition** is the here instead denoted "*value factor*", which is the difference between the mean price in the system and the obtained mean price for a certain power source or demand. But also this "*value factor*" depends on the system set-up. **The other definition** of "*profile cost*" is in a published paper defined as "*Integration costs of VRE are the additional costs in the residual power system that VRE impose compared to an ideal benchmark*". As shown in this report it is not possible to allocate this defined "*profile cost*" to specific sources since it matters, e.g., in which order the different changes are implemented. If the cost increases in the remaining system then the question is if this depends on "*lack of flexibility*" or "*caused need of flexibility*"? With a relevant market design, this will be considered by market participants. There are also other detailed applications of the proposed method, that have large implications on the result.

c) The concept of "*integration cost*" is not clear and it is hard to see the usefulness of that. The reason is that the term is system and definition dependent which means that a "*correct value*" cannot be set.

d) With a cost reflecting market design it is hard to see the value of making "*integration cost*" calculations. In e.g. the European market, with comparatively low capacity payments, the "*value factor*" is already included, since the investors in power plants have to consider the real income, which then includes the "*value factor*". Concerning grid costs, there are different approaches in different countries but in e.g. Sweden the power producers have to pay both a yearly grid tariff and also for grid upgrades. So also grid costs are integrated in the market. In most markets also the imbalance costs are included which then have an impact on competition between different sources. To conclude: "*When wind and solar are in the markets, there are no hidden costs that they would not pay – profile costs are seen by the producers as a lower market value, and balancing costs are paid in imbalance settlement. Grid costs are paid in grid connection fees and grid tariff.*" However, it is not trivial to construct a "cost reflecting market" but this is certainly the goal in order to obtain a socio-economic and sustainable power system.

e) When two specified systems, A and B are compared, then it is hard to see the value of calculating an "*integration cost*". It is better to compare these two set-ups concerning, e.g., reliability, total cost, environmental impact etc. To study other systems than these two, set-up C, it is hard to see in which way an unclear "*integration cost*" from the comparison of systems A and B could be used for alternative C.

General conclusion

There is certainly a large value in comparing different scenarios for the future. E.g. concerning how to upgrade the transmission grid etc. It is certainly also a value of splitting up the costs in production, grid and balancing in order to get a better understanding of the challenges. It is certainly correct that LCOE is NOT the total truth of the costs in the system, but at least this cost can be clearly defined with use of investment costs, interest rates and utilization time. But to then add a general "*integration cost*" is not correct if the idea is to add it to specific LCOE:s and also use this cost for other comparisons. There is certainly a need to estimate the total cost for different future systems and develop the market rules in order to, as much as possible, obtain a cost reflecting market. With a cost reflecting market, the investors have the possibility to choose the investments that the society needs.

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1 Introduction

An important issue for a sustainable development of the society is the design and market structure of the future power system. There are many options including wind power, solar power, nuclear power, flexible demand, amount of Electric Vehicles including sizes of batteries and their flexibility, electric roads, electrification of industry, storage such as hydrogen, pumped hydro or batteries, flexible electric heating or district heating etc.

All these options will impact the requirements on the rest of the system. If, e.g., there is a lot of electric heating, then this will require more peak capacity, to be used in very cold situations. If an industry or transport system uses hydrogen from electricity via electrolysis, then the existence of a hydrogen storage will also have an impact on the need of peak capacity, since these users could use stored hydrogen instead of directly produced hydrogen. Different production alternatives and their availability during peak load will also have an impact on the need of other peak units. If solar power mainly contributes to the energy supply at low demand, then the impact is very different compared to if this source contributes to a peak demand. The electric grid will also be designed differently depending on the type of production and demand.

This means that simple measures as "*cost per MWh*" (for producers) or "*consumed MWh/year*" (for consumers) are certainly not enough to find an economically optimal system for the future.

If all costs are included in the market signals (such as high true-cost reflecting price in peak, all actors pay for their grid costs etc), then the different actors (producers and consumers) will have the incentive to take the right decision. However, this design is not trivial. Many markets are based on short term marginal costs, but for investors it is certainly hard to estimated future prices since the future is always uncertain.

The aim of this report is to go through the challenge of "*total system costs*" which is how to estimate the total cost for an assumed future power system set-up, and how to split it up in different parts. It has then been argued that one can make this calculation for different set-ups and the part concerning "*integration cost*" then refers to the idea of how to allocate cost differences between different simulation results to different market actors.

The structure of the report is:

- Chapter 2: Definition of "*total system costs*", how this cost can be split up in parts, examples from two published reports (section 2.2), and challenges concerning how to estimate the total cost (sections 2.3-2.4) . A result from a study, where total system costs are estimated, often include the "*value factor*", which is also described in section 2.5.
- Chapter 3: Definition of "*integration cost*" and challenges concerning how this can be estimated. One part of the "*integration cost*" is the "*profile cost*".
- Chapter 4: Numerical examples. There is a base system and this is then modified in order to illustrate how different assumptions impact the size of the

"*value factor*" and the "*profile cost*". Tested changes include CO2 cost, amount of wind power, changed order of integration of wind power and storage, capacity or energy replacement and impact from optimization.

- Chapter 5: Actual market handling of wind power in Sweden.
- Chapter 6: References.

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Keywords

Wind power, power system costs, integration costs, profile cost, value factor, LCOE

2 Total system costs

When a future power system is studied, there are several options of power plants. An example of costs based on specific investment costs, building time, interest rate during the construction phase, availability and utilization time for these are shown in Figure 1.

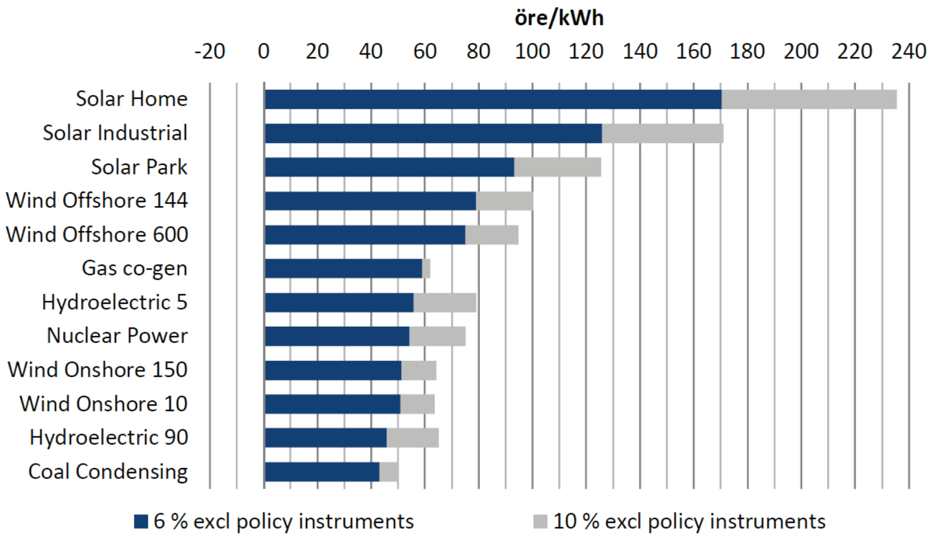

Figure 1 Estimated LCOE – Levelized Cost of Energy: The cost of electricity generation for commercial technologies that only generate electricity, excluding policy instruments with 6 and 10% cost of capital respectively. (Nohlgren, Svärd, Jansson, & Rodin, 2014)

However, a power system needs not only power plants, but also a grid from the production to the consumers, and also margins and equipment for a continuous balancing in order to obtain a stable power supply.

"*Total system costs*" is then defined as the total cost for a future power system. When going to higher shares of Variable Renewable Energy such as solar and wind, it's not enough to look at power generation system alone. The flexibility will come increasingly from the other sectors that also need to be decarbonized by replacing fossil fuels with electricity, e.g. heat, transport and industry. This then includes all production costs and grid costs, both operation costs (OPEX) and investment costs (CAPEX). Here we will study this for a specific future scenario.

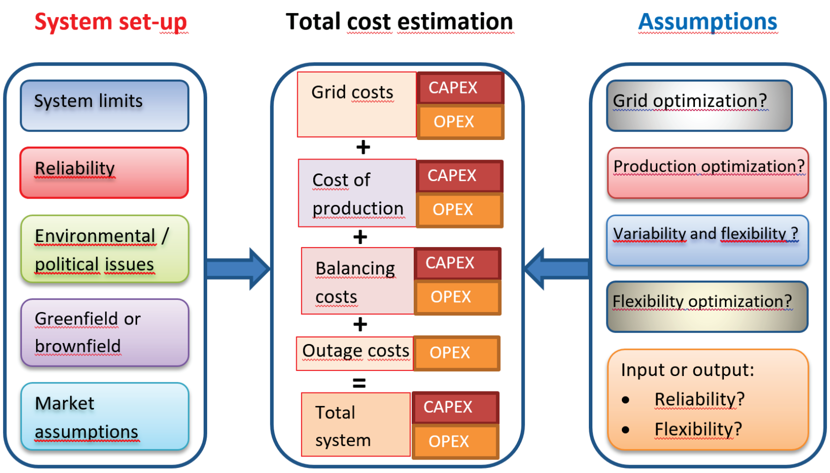

Figure 2 General set-up for calculation of total system costs for a certain scenario.

A part of the total system cost is often denoted "balancing costs" which then consist of specified costs for how to keep the balance in the system. This part is certainly essential and includes frequency control, costs for margins, short circuit power, reactive resources for keeping the voltage etc. It can, however, be noted that both CAPEX and OPEX for the balancing costs are normally referred to either as grid costs or production costs, so it is important to consider all costs exactly once, to make sure not to add them multiple times to total costs. Figure 2 shows a general set-up of what has to be considered. We here divide the inputs to "System set-up" and "Assumptions", but there is not a totally clear difference. The "System set-up" is on a more general level while "Assumptions" goes into more details.

2.1 SYSTEM SET-UP

The set-ups concerning how to estimate the total cost for a future power system can be different set-ups concerning, e.g.:

a) **System borders:** Do we only study a specific country/area or also the neighboring areas? If we to some extent consider other areas (e.g. neighboring countries), what do we assume about them, and how to handle the trading with these countries?

b) **Reliability**: How to treat reliability/adequacy? One possibility is to set a LOLP (maximum Loss of Load Probability) limit. Other possibilities are to consider a certain volume of strategic reserves, or requirements of a certain amount of capacity within a certain part of the system. Another alternative is to assume a high cost for non-served energy. If this is very high (e.g. around 5 Euro/kWh) as in Sweden ("*Disconnection price is the price that prices the Balance Manager's Balancing Power at Critical power shortage as this has been in Underbalance. The disconnection price is 5,000 EUR / MWh*", translated from (Svenska Kraftnät, 2019) page 16) then the question is how this high cost will impact the consumers. Will they still consume when this is the marginal cost for energy in the system? Instead of having reliability limits or costs as "input" (in the previous examples) one can treat it as "output". One example of this is "*the result is LOLP is 0.7h/year*", as in (Svenska Kraftnät, 2019), Figure 22. If the application is not stochastic (assumption of a fixed amount of available capacity from different sources during each hour), then LOLP cannot be estimated, since the definition is based on probabilities.

c) **Environmental/political issues:** Is there, e.g., a CO2 "limit", an assumed "CO2 cost", a certain share of renewable power, no net-import from countries with CO2-emissions, no import at all from countries with CO2-emissions, no nuclear power in future, support for nuclear power in future, etc.

d) **Greenfield/brownfield:** If we study a certain future system: What is then assumed concerning the "base system", which we already assume that it exists (and thereby the CAPEX is not included as a cost). A "Greenfield" study means that we start from scratch (all CAPEX included), while "Brownfield" means that we assume that some sources/grids/balancing-services are there already from the beginning.

e) **Market treatment:** Do we assume that investments are performed if they are found profitable by market actors (e.g. production unit investments), or do we assume that "we should build the most economic efficient system". This is, e.g., strongly connected to the "system limits". Market actors behavior may result in both large export or large amounts of import while "how should we meet the demand in our country" can provide any kind of trading amount with neighbors.

So there are certainly many different ways of how to set-up and analyze a future power system. This will have a significant impact on the type of result that one can get. Here we will first start with some analyzing examples in section 2.2 and then we will go in to more details of the consequences of selecting different set-ups and assumptions in section 2.3. In section 2.4 we will finally study how to split the different costs into different parts when total cost is divided into different parts.

2.2 EXAMPLES FROM PUBLISHED REPORTS

Below there are two examples of studies where the aim has been to estimate the "*total system costs"* for different systems. These are just taken as examples in order to show different approaches and corresponding challenges. Both examples divide the total cost into different parts, and then the total cost is obtained as the sum of the different parts. The aim is not to comment on what is right, wrong, realistic or not realistic in these reports, but just to take as a background for further studies. The real challenge is to make a "realistic" or "correct" model of the future, which by definition will be uncertain since the future is always uncertain. Therefore, what policy makers are doing is often to create *scenarios* for potential future developments.

2.2.1 Example 1: Future Sweden

We start with an example, which is from (Bruce, o.a., 2019) and was published in August 2019. In the report, one has studied different set-ups for a future Swedish power system. The results of the costs for the different scenarios are shown in Figure 3. As shown in the figure, the total costs have been split up in different parts, which are then added to the total cost. The aim is to meet a specific demand, so the assumptions on the demand (fixed or flexible/price sensitive) is also essential.

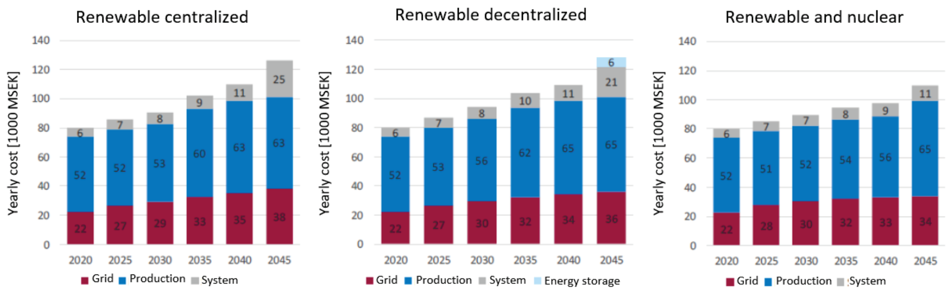

Figure 3 Development of the total cost for the different scenarios in (Bruce, o.a., 2019), page 8 (translated)

In (Bruce, o.a., 2019) where results are shown in Figure 3, the following definitions are used:

Grid: Stated on page 47: "*The total cost of the three production scenarios includes the costs of reinvestments, connection of new electricity generation and electricity consumption, costs of market integration with surrounding countries and between electricity areas, and system reinforcements in electricity areas and the driving forces of weather protection and digitalization. The sum includes investments in both local and regional networks and transmission networks, and is stated in the 2018 price levels.*" (translated from Swedish).

Production: (Bruce, o.a., 2019), page 83: There are three different production scenarios. They have different combinations of power sources. The differences are in Sweden. The surrounding system (outside Sweden) seems to have the same set-up, but will be operated differently depending on the selected Swedish system. The rules are the same (perfect use assuming perfect competition), but the real operation per hour will change depending on the prices and net-production in Sweden. For CAPEX there are (not transparent) investment costs, interest rates etc. For the OPEX, an hourly-based system operation simulation is performed for North European power system. One specific hydraulic year is used: "*Hydropower is expected to continue to produce approximately 65 TWh / year in all scenarios*", translation from (Bruce, o.a., 2019), page 83. They use a combination of the system simulation softwares Times and Apollo. Details are not available. There is not the same amount (TWh/year) of trading with the surrounding areas in the different scenarios.

Demand: (Bruce, o.a., 2019), page 84: The demand has the same yearly consumption, basic consumption level per hour and flexibility (to move demand to another hour) in all scenarios. The flexibility includes electric heating (could be decreased and reheated within 6 hours during cold season) and the Hybrit project (making steel using hydrogen from a hydrogen storage where the hydrogen is produced from electricity) which could reduce consumption during a shorter time, but "paid back" in other hours. Concerning electric vehicles it is stated: "*The profiles on demand for electricity are based on historical electricity use that has been adjusted for additional electricity use. The biggest differences are that "smart electric car charging" is added based on a study from the PUSS-EL project and that increased demand for electricity will be added in the form of a base demand for electricity. "Smart electric car charging" here refers to electric car charging which primarily takes place at night when the demand for electricity is lower*" (Bruce, o.a., 2019) page 84. Unclear flexibility outside Sweden.

Balancing (=System): Here, in this report, we will use the term "*Balancing*" since "*System costs*" (which was used in (Bruce, o.a., 2019)) is here used as a term for the total cost. The "*balancing*" part refers to different types of "*system services*" or "*balancing costs*". This includes frequency services and handling of inertia. The method of how to estimate the total cost is in (Bruce, o.a., 2019) based on a "*base cost*" of 6000 MSEK/year, which is the mean balancing cost in the yearly report from the Transmission System Operator Svenska Kraftnät for the years 2017 and 2018. The estimation of these costs has, according to the report (unfortunately not shown in the (Bruce, o.a., 2019), but information is received from the ones who wrote the report) been estimated as follows:

1) For each hour in a given scenario, the proportion of non-synchronous production, SNSP, is calculated. Synchronous production is electricity generation from hydropower, nuclear power, cogeneration and gas turbines. Non-synchronous production is electricity production from wind and solar power.
2) The system cost per hour is then linked to this percentage. A normal system cost (i.e. what we have now) is called x which refers to the "*system cost per hour*". This means that x = [6000 MSEK] / [8760 hours / year] = 0.68 MSEK / hour.
3) At high SNSP, the system cost per hour is then calculated according to an exponentially increasing model for different intervals (with inspiration derived from Ireland's "deficiency factors"), for example in this way:
   a. SNSP <55% ➔ x, ie the same as now
   b. SNSP = 55-70% ➔ 4x
   c. SNSP = 70-85% ➔ 16x
   d. SNSP> 85% ➔ 32x
4) Then all these costs are summed up for each individual hour. In this way one gets the system cost per year for a future system as well.

This is a new method invented by the authors of the study, and is not based on any real costs and not based on any suggestions in any report. I.e., this is a bit artificial.

E.g. points a.-d. in 3) are not motivated or confirmed at all. But it is essential for the result.

Energy storage: (Bruce, o.a., 2019), page 40: *In the scenario "Renewable decentralized", investments are made in energy storage between 2040 and 2045, which increases the annual capital costs. In the scenario, energy storage is needed for Sweden to be able to meet the peak power without imports during a normal winter.* (translated).

2.2.2 Example 2: NEA-IEA study.

The second example is the NEA/OECD report (OECD/NEA, 2019) "The Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables" from 2019. Figure 4 shows an example from that report. The figure shows the difference in total cost between two scenarios. Technically this report does not calculate the "*total cost*" but more the "*difference in total cost*" between two specific scenarios.

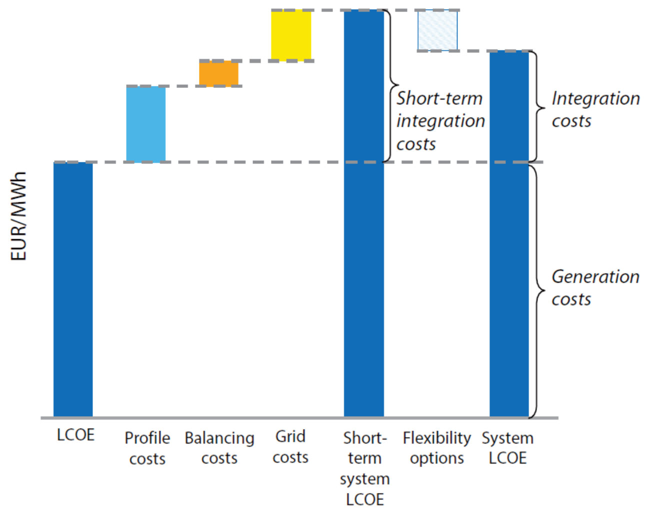

Figure 4 Differences in total cost between two scenarios in (OECD/NEA, 2019), page 17. "Flexibility options include interconnections with neighbouring countries, a relatively high share of flexible hydroelectric resources, demand-side management (DSM) and several storage options". (OECD/NEA, 2019), page 15.

The set-up for the NEA/OECD study was the following:

1. The data used is for a two-area system that is simulated for one specific year. In each area, there are several possible resources with different costs (CAPEX – Capital Expenditures and OPEX – Operation expenditures) and load factors. Demand, wind power, solar power, and run-of-the-river hydro are, for each hour, treated as time series with specific values in MWh/h. Regulating hydropower with storage has, for each hour, a certain amount of inflow and a reservoir which could, for some time, store the inflow. Thermal power plants, nuclear, coal, Open Cycle Gas Turbines - OCGT and Combined Cycle Gas Turbines - CCGT have specific operation costs per MWh and investment costs per MW. There is also pumped storage in both areas with a certain efficiency, storage capability and capacity. There is a limited transmission capability between the two areas. Detailed data is not available.

2. The methodology is based on a classic capacity expansion approach that is deterministic and minimizes total cost; investment + operation cost. The used tool is GenX (Jenkins & Sepulveda, 2017). This is a "*brown field study*", where the hydropower (run-of-the-river, hydro with storage and pumped storage) is assumed to be already available (so no investment costs are added for these sources), but for all the other sources all costs are included. VRE (Variable Renewable Energy), wind and solar, are treated as specified input levels, different for different scenarios, but the amount (optimal capacity and yearly energy production) of the thermal power plants (nuclear, coal, CCGT, OCGT) is an output of the capacity expansion. Coal is never used because of too high cost including assumed CO2 cost. The energy production per hour for the thermal units, regulating hydro and pumped storage hydro, as well as trading between the areas per hour, are also outputs from the model. There can also be curtailments of VRE (Variable Renewable Energy = Wind + Solar) if this is found necessary and/or economic. In summary the capacity expansion results then include, per source, total yearly production and total capacity installed.

3. From these outputs, for different system set-ups, one can calculate the economic implications for each case such as total cost, cost/MWh, integration cost etc. The main objective of the NEA/OECD study was to compare these costs when the amount of VRE increases.

The division of costs between different parts is shown, c.f. Figure 4, in a slightly different way in Example 2 compared to Example 1. Here the different parts are:

LCOE: Levelized Cost Of Energy is the fundamental cost per MWh for different power sources for the "base scenario". The level of these have a large impact on the results since one uses optimization to combine different sources (in Example 1 one used scenario). It is clear from the estimation of "*integration costs*" that the LCOE does not include, e.g., connection costs which, e.g., is the case when e.g. LCOE for wind power is reported in Sweden, c.f. section 5.

Profile cost: This "*idea*" is based on that there is a basic power system (e.g. nuclear) + a "*remaining power system*", consisting of the rest of the production sources. If we then replace the nuclear power with the same amount of energy in another source (e.g. wind power), then the "profile cost for wind power" is the <u>extra cost</u> in the "*remaining power system*". However, a <u>clear definition</u> of how this is estimated is not available in the report and it has not been possible to get this from the authors either. Details of this idea are provided in section 3.

Balancing cost: It is stated (page 17): "*Balancing costs refer to the increasing requirements for ensuring the system stability due to the uncertainty in the power generation (unforeseen plant outages or forecasting errors of generation).*" In this report they do not make any own estimations for the studied case, but they state (page 63): "*In conclusion, the most recent estimates for balancing costs lie in a range of EUR 2 to 6 per MWh$_{VRE}$ for wind power in thermal systems, while costs for solar PV and wind power in hydro-based systems are much lower, less than EUR 1 per MWh$_{VRE}$*".

Grid costs: It is stated on page 88: "*No direct attempt has been made to capture either connection costs or transmission and distribution (T&D) grid costs in this modelling work, since each region is considered as a single node. Nevertheless, some estimates for the T&D*

and connection costs are taken from the literature and added to the cost of electricity provision, in order to obtain a more complete evaluation of the whole system costs". And further on page 115: "*…the costs of building or reinforcing the T&D infrastructures, the costs of connecting each individual plant to the transmission grid as well as an estimate of the unaccounted balancing costs are assessed based on literature estimates.*" Further on page 17: "*Grid costs reflect the increase in the costs for transmission and distribution due to the distributed nature and locational constraint of VRE generation plants. However, nuclear plants also impose grid costs due to siting requirements for cooling and transmission. Grid costs include the building of new infrastructures (grid extension) as well as increasing the capacity of existing infrastructure (grid reinforcement). In addition, transmission losses tend to increase when electricity is moved over long distances. Distributed solar PV resources may, in particular, require investing in distribution networks to cope with more frequent reverse power flows occurring when local demand is insufficient to consume the electricity generated.*". Grid costs were taken from literature and not from a specific study. In Sweden, these costs are included in LCOE, c.f. section 5.

Connection costs: This part is not directly shown in Figure 4, but they state on page 17: "*Connection costs consist of the costs of connecting a power plant to the nearest connecting point of the transmission grid. They can be significant especially if distant resources (or resources with a low load factor) have to be connected, as can be the case for offshore wind, or if the technology has more stringent connection requirements, as is the case for nuclear power. Connection costs are sometimes integrated within system costs, but are sometimes also included in the LCOE plant-level costs.*" However, in the report a connection cost was added and it is stated (page 17): "*Together, the four categories nonetheless make up the bulk of system costs. Figure ES2 below summarises them.*". "*Figure ES2*" in (OECD/NEA, 2019) is the same as Figure 4. In Sweden, these costs are included in LCOE, c.f. section 5.

2.3 DIFFERENT ASSUMPTIONS FOR SYSTEM DESIGN

There are different ways of setting up a system simulation. For the interested one, there is some additional information in (Söder L. , 2017) (Holttinen & al, 2018).

Example of selection of set-ups are shown in sections 2.3.1 - 2.3.3.

2.3.1 General set-up and assumption

a) **System Set-up: Green- or Brownfield**: 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. This is then denoted *Brown field studies*. 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.

b) **System Set-up: Market 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 here, 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. Under ideal market competition, cost minimization leads to the same results as market driven investment and operation. In (Gerres, o.a., 2019), this is demonstrated using a model for cost minimization CAPEX+OPEX the investment is recovered through incomes from the energy market and the capacity market.

c) **Assumption: Grid and production optimization for <u>each</u> case**: In this case, when one compares different alternatives, one assumes a perfect system for each case. However, this then means that one now decides if we go for alternative A or B and then optimizes all other issues in the society for each specific case. In reality there is a continuous development over time.

d) **Assumption: Grid and production optimization for a <u>base</u> case**: In this case one makes a general set-up for all cases (e.g. selected transmission system, assumed flexibility etc) and then only optimizes a limited amount of options for the future.

e) **Assumptions of Parameters and Variables:** A question is then what the aim of the study is. The **Input Parameters** are decided from the beginning while the **Output** are the values of selected **Variables**. 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. Some examples of selections are:

   - 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, to get enough capacity for the required reliability.

   - If one has a restriction on S*hare of renewables* or *maximum CO2 emissions*, and at the same time has an assumption on market driven, then there must be a possibility to achieve 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*. This means, mathematically, that one sets up a goal and then the system simulation decides on which CO2 price that is necessary to get the required CO2 reduction. In fundamental economic analysis, if we assume "*market driven investments*", 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 the short term marginal cost in order to be profitable. This means that this *marginal* can be treated as a variable.

f) **Assumptions on Variability:** Since we discuss the future, we do not have "*correct data*". There will then be a lot of uncertainty and variability. The demand (including heating, cooling, EV charging), solar power and wind power will vary continuously both in the studied area and in the neighbouring areas. Will one then study all possible combinations (which is not possible) or only an "*average year*"? For hydro power the inflow also varies both over each year and total precipitation during each year. And there are correlations between all these varying issues. So a "*perfect*" simulation should consider as much as possible of all this. If one only studies one year, then the question is, e.g., how windy it is during the peak load situation, i.e. in reality the capacity value of wind power.

g) **Assumptions on demand flexibility:** In future power systems there will certainly be more flexibility than today. This depends on 1) ICT technology makes it possible for consumers (or aggregators/ retailers) to adjust the consumption to the market situation, 2) Electric vehicles, use of hydrogen with storage, electric heating with thermal storage are all examples of flexibility that will increase in the future. The question is then which assumptions that are made. One can assume, e.g. i) No flexibility, ii) A certain amount of technical flexibility, no matter the need, iii) Flexibility will evolve if it is profitable, iv) if peak prices are extreme (e.g. 5 Euro/kWh), then a certain market will occur. A recent Swedish example is the Hybrit project (use hydrogen instead of coal in the iron mining / steal industry). The power company Vattenfall has presented a case where they find that it is realistic to have 14 days of hydrogen storage and 180 % electrolysis capacity (IEA Webinar: Presentation by Vattenfall, starting at 50:50, 2021).

h) **Assumptions on production flexibility:** On the production side there is a lot of possible increased flexibility. The question is how this is considered in the modelling. One can, e.g., assume i) No flexibility in wind/solar/nuclear power, ii) frequency control in nuclear if profitable (right now not in Sweden but in France), iii) frequency control (fast-FFR or ordinary primary control) in wind or solar power if profitable, iv) compulsory frequency control (fast-FFR or ordinary primary control) in wind and solar power, etc.

In chapter 4 there are some numerical examples where the impact from different assumptions are shown. Some comments are:

- **System Set-up: Green- or Brownfield**: Only Brownfield studies are studied in chapter 4. The impact of increasing wind power is studied, where all other sources are assumed to have the same installed capacity. In the "*more Green-field approach*" in Case 3 and Case 4b, the nuclear is kept constant, but the amount of the other sources are optimized. In a "*complete Greenfield study*" no specific amount of any source capacity is handled as input.

- **System Set-up: Market Objective**: In Case 3a the total system cost is minimized. This leads to that the selected amount of wind power is not profitable since the received price does not cover the cost. In Case 3b it is instead assumed that only as much wind power is build to the income covers the cost. This leads to lower amount of wind power and higher price

- **Assumptions of Parameters and Variables**: In Case 2, the amount of installed capacity in different sources is **input** and total cost is **output**. In Case 3, the total cost is minimized and the capacity in different sources is instead the **output**. In Case 2 and Case 3a the **input** is that total production can cover peak load (i.e. curtailments = 0), while in Case 3b the amount of load curtailments (or flexible demand) is the **output** of the calculation.

- **Assumptions on Variability**: In all cases studied in chapter 4, the same wind profile is used. This specific wind profile has a certain amount of production during peak load hours. In reality this is different in different years. Some years the wind is low at high demand, sometimes it is high. In order to get a "correct" estimation of the correlation, then many years have to be studied.
- **Assumptions on demand flexibility**: Case 4 includes a flexible demand which will be decreased if the market price is higher than 2000 EUR/MWh. If we assume that this will also cause the market price to be 2000 EUR/MWh when this demand flexibility is activated, then this has a large impact on the profitability of all power production sources in the system. However, the impact is different on different sources depending on how high the production is during this specific period.

What is not included in the examples in Table 3 from chapter 4 is **flexible demand** or storage. If there are large price differences then this will certainly increase the interest to invest in flexible demand.

Table 3 Results from some case studies.

Case	1	2d	2e	2f
Wind: Energy share	20%	30%	40%	50%
Nuclear: Energy share	21%	21%	21%	19%
Gas-CC: Energy share	34%	32%	26%	21%
CO_2 price: [Euro/ton]	80	80	80	80
Wind LCOE [EUR/MWh]	37,08	37,08	37,08	37,17
Wind value [EUR/MWh]	80,21	79,33	75,50	57,30
Wind profit [EUR/MWh]	43,13	42,25	38,41	20,13
Nuclear LCOE [EUR/MWh]	63,28	63,28	63,68	67,43
Nuclear value [EUR/MWh]	81,16	80,07	77,94	71,19
Nuclear profit [EUR/MWh]	17,88	16,79	14,26	3,76
Gas-CC LCOE [EUR/MWh]	86,29	86,86	88,60	91,39
Gas-CC value [EUR/MWh]	81,19	80,19	79,94	79,92
Gas-CC profit [EUR/MWh]	-5,10	-6,67	-8,65	-11,47
Mean price [EUR/MWh]	81,16	80,07	77,42	66,51
Standard deviation [EUR/MWh]	74	54	126	265

Table 3 shows results from some case studies. What is changed from Case 1 is an increased amount of wind power from 20% of energy up to 50% of energy. What happens is that

- The price (= marginal cost) decreases.

- The price volatility increases significantly at higher percentage of wind power. This means a significantly higher interest to have flexible demand (consume at low prices) and/or use storage (charge at low price periods and use in high price periods). This is, e.g., the assumption in (IEA Webinar: Presentation by Vattenfall, starting at 50:50, 2021) where wind power is assumed as the dominating resource to provide extra energy to the Hybrit project.

2.3.2 System borders: Treatment of neighboring systems

Assume here that we study the expansion of area/country A, which also has neighboring systems B and C. The question is then how the surrounding areas are considered. Here are some examples:

i) **Neglect neighbors**: This means that we study area A as isolated from the neighbors. Then all balancing has to be handled inside area A.

j) **Do not consider any impact on neighbor operation**: This means that one, e.g., take historical transmission to neighboring areas as input to the actual study.

k) **Include neighboring systems in OPEX/CO2**: This means that when one simulates the operation of area A, then also changes in neighboring areas are considered. However, the question is then also how to handle “costs”. Assume that one makes an investment (a power plant) in area A. Then this will decrease use of other power plants (and maybe CO2 emissions) in both area A and the neighboring systems. Are then only the changes in area A considered or also in the neighboring areas? Or for a case when one compares 2 (or more) cases: Does this mean that whole OPEX (for whole system) is compared, or only OPEX in area A? Different A-systems will probably also cause different OPEX/CO2-emissions in neighboring systems.

l) **Include neighboring CAPEX interconnections**: In the system optimization, this means that one should have the optimal interconnections (amount) to neighboring systems, from economic point of view.

m) **Include neighboring system CAPEX**: In the system optimization, this means that one should consider all investments also in the neighboring systems. If area A has different set-ups, then it is probably efficient to also make different investments in the neighboring systems, e.g. internal transmission.

n) **Include changed flexibility amount**: With a possible larger amount of volatile trade with neighbors, then the prices will be more volatile also in their systems. Will one then assume an increased amount of flexibility in their systems or not?

The numerical examples in chapter 4 only treats one isolated system with no transmission limits.

2.3.3 System set-up and assumptions concerning reliability

Here we assume, as above that we study the expansion of area/country A, which also has neighboring systems B and C. The question is then how to handle the required reliability. Here we mean “*adequacy*”, i.e. that there should be enough capacity to meet the demand. An additional issue is "*system stability*" or "*system security*" which is much more complicated (since it require dynamic simulations for all possible contingencies) and not so often included in details in system expansion. Different options of how to treat this includes:

o) **Set VOLL in A**: VOLL = Value Of Lost Load. This is noted as "*Outage costs*" in Figure 2. To set this value means that one requires consumption – production balance in each area, and curtailment is set as a "production resource" at a cost. One example of a cost could be the cost set by the TSO in Sweden. If the system operator cannot purchase electricity to compensate for a lack of production, and they then have to disconnect customers, a disconnection price of EUR 5000 per MWh must be paid (Svenska Kraftnät, 2019). In this way the resulting reliability is set by the market, and the assumption means that this price reflects reality and is politically accepted.

p) **Set VOLL in A and its neighbors**: In this way, which is closely linked to the previous option, then also the lowest cost to keep the reliability in whole interconnected system is achieved.

q) **Set LOLP/EENS < target in A, invest in A**: LOLP = Loss Of Load Probability (measured in expected hours per year when not all demand can be met, which leads to involuntary curtailments). EENS = Expected Energy Not Served, where this energy is the energy loss caused by LOLP. This assumed strategy means that one, e.g., invest in OCGT or demand flexibility in order to achieve a certain LOLP (Loss Of Load Probability). Examples of LOLP targets are France and UK where they have a requirement of Loss Of Load Expectation = LOLE = maximum 3h/year (Söder, o.a., 2020).

r) **Set LOLP/EENS < target in A**: If there is not a specific requirement that the reliability target should be met in area A, then it might happen that the cheapest option (or assumed that this is "selected in a liberalized market") is to have more transmission to neighbors or even more production/flexible demand in neighboring systems.

s) **Assign a margin**: Another reliability metric is to set an amount of available firm capacity higher in a margin than the peak demand.

t) **Be independent of neighbors**: This is not necessarily the same as "isolate area A from neighbours". One can, e.g., assume that "*we normally use trade when available, but we want to have enough capacity to meet the peak demand within area A*". This then, probably, causes high investments of rarely used power plants of flexible demand in area A with very low probability to be used.

In the numerical examples in chapter 4 this is handled in the following way:

- **Set VOLL in A**: In Case 4 the VOLL is set to 2000 EUR/MWh.
- **Set LOLP/EENS < target in A**: The LOLP is set to 0 hours in Case 1, Case 2 and Case 3. A fundamental challenge with this set-up is that the peak unit will not get any CAPEX covered if the price is set by the marginal operation cost.

2.3.4 System set-up and assumptions concerning storage

Storage has a large impact on system flexibility and cost. However, storage can exist in many parts of the system. Figure 5 shows an overview of where storage can exist.

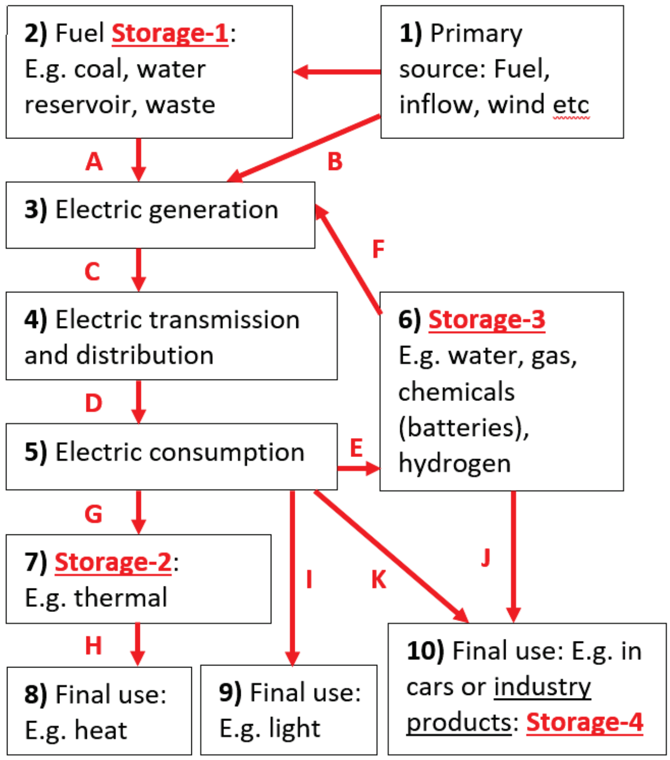

Figure 5 Structural description of storage opportunities in power systems

The different boxes in Figure 5 are related in the following way.

1) The primary energy resources are wind, solar radiation, precipitation or fuel, etc.

2) The primary resources may be stored in the form of fuel storage or water reservoirs (Storage-1). For solar-thermal power it is also possible to store heat in salt which later can be used for electricity generation. The possibility of this is interesting at very low electricity prices at, for example, high solar and / or wind power.

3) Electricity can then be generated in different power plants either from the stored energy, **A**, or directly for the source, **B**.

4) The generated electricity must then be transferred to customers, **C**.

5) The consumed electricity, **D**, can then be used either directly, **G-I**, or for something that can be used later, **E**. Items 3)-5) are instantaneous, i.e. without storage or delays.

6) One way is to use electricity to, **E**, **charge batteries, pump water to a higher reservoir, produce gas or some synthetic fuel "electro-fuels", i.e. storage (Storage 3)**. What one produces can either be used for electricity production, **F**, or used for other issues, such as the operation of cars (gas cars, electric cars) or in industry, **J**. Water that has been pumped up to a higher level or if pressure storage has been used, can only be used for electricity production. For produced gas / fuel / car batteries, for example, 10-90 percent can be used for direct consumption and the rest is used for electricity production, **F**. There is thus a strong connection between storage and use. An example is power-to-gas, where one makes a gas (H or CH4) from electricity. If one makes car fuel, the utilization time for the plant can be high, but if one only uses "surplus", the utilization time will be so low that the cost of capital can be very high.

7) When there is a need for heating or cooling, there is no need for a direct "production" of cooling/heating because there is normally a "thermal inertia" in buildings, freezers, etc. This means in practice **a storage layer between supply (of heating/cooling) and actual needs (Storage-2)**. Examples are district heating systems, heat pumps in buildings or electric boilers.

8) End use in the form of the required temperature, where there is a layer between supplied electricity and heat demand. An additional flexibility may be that there is another energy source in the form of, for example, solar heating and/or a fuel-fired boiler which means that consumption can be flexible.

9) However, some electricity consumption is direct, e.g., operation of the subways, lifts, lighting, where there is no storage between supply and use.

10) For car operation (electric cars or electro-fuels) there is a layer between electricity consumption and actual needs. Also applies to lap-top / rechargeable flashlights etc where there is a built-in battery. For motors in industry and for electric roads the electricity is used directly, **K**. It is also possible, and not un-common, to only produce industrial products at comparatively low prices. This formally means **industrial product storage (Storage-4)**.

In order to study "*storage*" in a power system it is therefore important to study the entire system where there is storage in several different places. One possibility is, for example, to pump up water to higher reservoirs in already developed rivers. This can probably only be seen as a solution to the "surplus challenge" by being able to get an extra use at very low electricity prices. To get more power when there is a great need, more installed capacity is needed. This can be seen as an example of how the consumption side and the production side of a storage can be different.

2.3.5 System set-up and assumptions concerning balancing

There are several challenges in order to keep the continuous balance in the power system. There is a **planning** before each instance including:

- **Market set-up**: Which prices do different actor see: Do they have a constant price, an hourly changing price seen already the day before, or a price corresponding to actual system state / marginal costs
- **Day-ahead bidding**: Which prices/volumes are offered to the market already the day before. Partly based on forecasts, for e.g. wind, solar and demand
- **Intra-day bidding**: During the day one can update the bids
- **Grid planning**: The capacities in the grids can be fixed or using dynamic rating, which means that they depend on temperature and wind.
- **Enough balancing resources**: For each instance, there must be enough capacities of different types in order to balance the changes from second to second. In Europe this is divided into different system services denoted:
  - FFR = Fast Frequency Reserve
  - FCR-N = Frequency Containment Reserve - Normal
  - FCR-D = Frequency Containment Reserve - Disturbance
  - aFRR = Automatic Frequency Restoration Reserve
  - mFRR = Manual Frequency Restoration Reserve

In the **<u>operation</u>** of the power system, there must be enough margins in order to handle:

- **Contingencies**: Outages of power plants and grid components
- **Forecast errors**: In e.g. wind, solar, load
- **Changes within trading period**: In Europe this is currently 1 hour or 15 minutes while it in Texas and Australia is 5 minutes.

The whole set-up must be both economical and reliable in a balanced way. What is currently happening in many places are that the demand has the possibility to participate in the balancing. Some examples are:

- Heatpumps, electric heating or electric vehicle charging can be directly connected to the day-ahead price and move consumption to hours with lower price.
- For summer 2020 the FFR market was opened the first time in the Nordic power system. In none of the participating countries there were any bids from producers. The bids to the market came from electric boilers, computer centers with UPS, large green houses and other demand.
- During 2018 there were, in Sweden, more than 2000 hours when the FCR-N prices were higher than the electric price. This means that it had been profitable to consume power (and spill the energy) just in order to be available for frequency control. This is also certainly interesting for wind power owners, but not yet applied to a large extent, c.f. (Wiklund, 2021).

- With the set-up presented for the "Large" Hybrit project, (IEA Webinar: Presentation by Vattenfall, starting at 50:50, 2021), there will be around 10 GW of electrolyzers (around 50 TWh/year) which can contribute to frequency control if they find it economical.

This means that if we study a future power system it is important to consider the possibilities and economy for different types of demand to compete on the balancing markets. One can also assume that the current markets will change their structure when new possibilities and challenges arise. Examples include:

- The Nordic FFR market is new since there is a need for it.
- The Nordic mFRR market will within some years include a capacity payment while in currently, 2020, only has an energy payment.

2.4 CHALLENGES IN SPLITTING TOTAL COSTS TO DIFFERENT PARTS

To calculate the total cost, this can then be seen as a sum of the different parts, as shown in Figure 6.

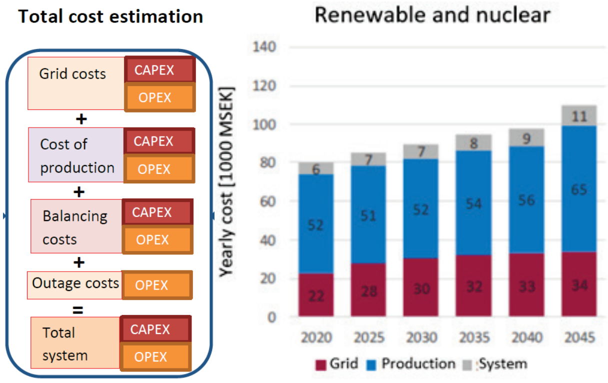

Figure 6 Calculation of Total system costs as a sum of different parts

There are, however, some challenges, which have to be considered when this is estimated so each cost is entered exactly once since the total cost is the sum of the different parts.

2.4.1 Production – Grid challenges

These challenges include that each cost should only be in one place, either in production or in the grid:

1) **Connection charges**: What is included in "*production investment costs*"? There are different set-ups in different countries concerning what is included in "*production costs*". First connection charges are a one-off payment, generally applied to all generators. These can differ depending on which grid the generators are connect to. The following definitions used by ENTSO-E can be used to classify them in both grids, distribution and transmission, although some connection charges do not fall exactly within this classification: **Super-shallow**: All costs are socialized via the tariff, no costs are charged to the

connecting entity. **Shallow**: grid users pay for the infrastructure connecting its installation to the transmission grid (line/cable and other necessary equipment). **Deep**: shallow + all other reinforcements/extensions in existing network, required in the transmission grid to enable the grid user to be connected. If a "*market based approach*" is used in the system simulation, then power plants are built if they are profitable, including grid costs. It is then important that these grid costs are a part of the production cost, not a "*grid cost*". Some examples are internal grid in a wind farm (which is often a "*production cost*") and also "*connection line from an off-shore wind power plant*" which in some countries is a "*grid cost*" and in some countries paid be the wind farm owner (i.e. a production cost).

2) **Losses**: Grid operation cost can include "*cost to purchase power to cover the losses*". However, if this is included as "*grid OPEX*", then it is important not to consider these costs in the production part.

3) **Bottlenecks**: In a market of the European type, there are formally 2 ways of considering "*bottlenecks*": One is that the TSO:s (i.e. grid owners) purchase power on the cheap side of the bottleneck and sells the power on the expensive side, i.e. this bottleneck creates an income for the grid owner. An alternative is "*counter trading*" where the TSO:s have to purchase expensive power on one side and "*sell back*" power on the cheap side of the botteneck, i.e. a cost for the TSO. If a "*market approach*" is applied in "*system simulation*" where grid owners are one part, then it is important to consider this "*production trading*" for the "*grid owners*". This is a non-issue if one do not treat grid-owners as a "*market participant*".

2.4.2 Consumption – Balancing challenges

There is a possibility to use flexible consumption as a balancing resource. These sources could, e.g., be price dependent, and/or offer system services. In a traditional market based simulation, the production is modelled as a "*supply curve*" and demand is modelled as a "*demand curve*", c.f. Figure 7. Assumption of "*social welfare maximization*" then leads to that the price and volumes are set in the point where marginal cost for production is the same as marginal value of consumption. This way of simulating implies that consumption that has a lower marginal value than the most expensive supply side resource will not be covered.

However, the question is how demand is modelled in the original simulation where the aim is to continuous balance production and demand. There are then, at least, two options:

4) **Price dependent demand**: In Figure 7 the demand is modelled (the red curve) as a decreasing curve, with lower demand the higher the price.

5) **Base demand with cost to decrease**: An alternative (black vertical line + red arrow) is to, instead, assume a fixed demand, but when prices increases then the demand is reduced from this level. In this way one can se "*demand decrease*" as an option to "*production*" and the cheapest option is used.

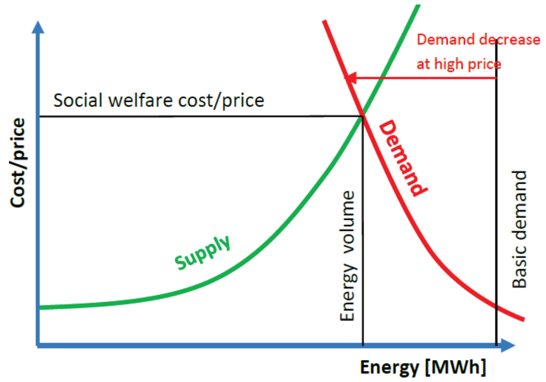

Figure 7 Supply and Demand curves in economic simulations

There is no fundamental difference in the outcome from these two methods. But in the second case there is a "*cost*" to decrease the demand. It can be noted that Figure 7 is valid both for "*operation cost: OPEX*" simulation and for "*total cost: OPEX+CAPEX*" investment simulations.

2.4.3 Production – Balancing challenges

These challenges include that each cost should either be in the production part or in the balancing part:

6) **Fundamental challenge**: A large part of "*balancing costs*" are often from the production side. But costs on the production side are mainly considered as "*production costs*". It is then important to evaluate whether *Balancing-costs-CAPEX* really means extra investments and Balancing-costs-OPEX really reflects extra operation costs. A challenge is also to define the benchmark, i.e. what do we start with.

7) **Consideration of margins**: The operation costs of the production in a specific scenario is often estimated using a simulation software. In this simulation it is then both possible and common to have different kind of "*margins*", i.e., "*spinning reserve*" margins. If this is applied then it is important to note that "*costs of spinning reserves*" are already included in the production cost simulation.

8) **Consideration of curtailments**: How are "*production curtailments*" handled? This is valid for, e.g. nuclear power at low prices or wind power at lower demand? This is sometimes classified as a "*balancing cost*" but alternatively as a "*reduction of production*", i.e., a changed "*production cost*". The important issue is that it should only be handled once.

9) **On payment for imbalances**: It is important that "*balancing costs*" do NOT include "*imbalance payment*" since this is not a physical cost but a transfer of money between different actors.

10) **On use of market prices**: When "*balancing costs*" are estimated from market prices, it is important to consider whether these costs are "*extra costs*" compared to costs already estimated as production costs.

11) **On "market design"**: In some countries, e.g. currently in Europe, it is common with hourly markets where "system services" are seen as the extra balancing services which are handled to keep the balance within each hour. In Texas, as an alternative, there is a central dispatcher, ERCOT, who changes the operation of each power plant every 5 minutes, based on bids from the producers. In the European set-up the "balancing costs" are often seen as the issues that the system operators handle, i.e. all changes with each hour. But in the Texas case, the role of the system operator is very different. Currently, in Europe, we move towards a "*quarter based market*". This will probably "*decrease the balancing costs*" since the system operators role is much smaller, since the volume changes within a quarter is much lower than within an hour. However, this means that more of the "*intra-hour balancing*" is instead moved to the producers. This will, probably, lead to that "*balancing costs*" will decrease in the future, but this does NOT mean (automatically) that the physical costs change, they are just moved to the producers.

2.5 DEFINITION AND ESTIMATION OF "*VALUE FACTOR*" FOR A POWER SOURCE.

Different power sources produce in different ways. Some produce depending on weather (wind/solar), some at high prices (peak plants) and some rather constant (coal/nuclear). This means that the revenue for a given yearly production is different depending on the timing of the production. This is formally a "*difference in revenue*" (not a physical cost) sometimes also called "*value factor*" or "*profile cost*".

The value factor is depending on the system set-up. If one, e.g., changes the amount of one source (e.g. wind power) between two cases, then the value factor can increase for some sources and decrease for other ones. The value factor then states the difference between the mean market price and the mean price that is received for the power plant. It does not say anything about the competition between different sources, or the profitability for certain sources. In the numerical examples in section 4 there is first one basic system set-up described, Case 1, in subsection 4.1. There are then several modifications of this base-case in subsections 4.2-4.6. They have all the same demand, investment costs for different sources and wind profile. But, there are several different other parameters. In Table 4 the different data are shown.

Table 4 Summary of costs, revenues, value factors in EUR/MWh for some case studies in section 4

Case	1	2a	2c	2d	2f	3b	4a	4b
Wind: Energy share	20%	20%	20%	30%	50%	60%	20%	61%
Nuclear: Energy share	21%	21%	21%	21%	19%	15%	21%	15%
Gas-CC: Energy share	34%	34%	5%	32%	21%	23%	34%	23%
CO2 price: Euro/ton	80	100	40	80	80	80	80	80
Wind LCOE	37,08	37,08	37,08	37,08	37,17	38,22	37,08	38,43
Wind value	80,21	93,50	54,23	79,33	57,30	39,96	85,50	41,95
Wind profit	43,13	56,41	17,15	42,25	20,13	1,74	48,42	3,52
Nuclear LCOE	63,28	63,28	63,28	63,28	67,43	81,68	63,28	83,53
Nuclear value	81,16	94,50	55,79	80,07	71,19	74,07	100,06	87,34
Nuclear profit	17,88	31,22	-7,48	16,79	3,76	-7,61	36,78	3,81
Gas-CC LCOE	86,29	93,27	117,48	86,86	91,39	98,82	86,29	100,56
Gas-CC value	81,19	94,61	75,47	80,19	79,92	88,05	100,32	113,57
Gas-CC profit	-5,10	1,34	-42,01	-6,67	-11,47	-10,77	14,02	13,01
Mean price	81,16	94,50	55,79	80,07	66,51	55,40	100,06	63,43
Mean consumer price	82,0	95,4	57,5	80,5	70,1	62,3	110,0	69,4
Wind value factor	-0,95	-1,00	-1,56	-0,74	-9,21	-15,44	-14,55	-21,48
Nuclear value factor	0,00	0,00	0,00	0,00	4,69	18,66	0,00	23,91
Gas-CC value factor	0,03	0,11	19,67	0,12	13,41	32,64	0,26	50,14

Table 4 shows how the "value factor" changes between different cases. Some comments/conclusions are:

- The "*value factor*" is not easily linked to any profit. Wind power is, e.g., profitable in all these cases and has a significantly negative value factor in some cases, while e.g. nuclear power has zero value factor for cases 1 and 1a-2d but has negative profit in one of the cases.
- The "*value factor*" is very different depending on the system set-up.
- It is **NOT** possible to state "*this is the value factor for this source*". It totally depends on the system set-up.
- A comment is also that the commonly used index LCOE is not constant. It also depends on the system set-up. For wind it increases with 4%, for nuclear it increased with 32% depending from the base case (Case 1) where all available capacity was used. This depends on that wind power, with lower marginal costs, replaces nuclear at high share of wind power, and with fewer operational hours the LCOE for nuclear power increases.
- In many countries (e.g. Sweden, c.f. section 5) wind power (and other sources) are paid by the market price. This means that the value factor is included in the payment and thereby considered by the investors. But it is not a part of LCOE.

3 Integration costs

The idea, in general, of an "*integration cost*" is to study the change of the total cost in the system at a certain change. We can illustrate this with a historical Swedish example. From 1970 to 1987 the Swedish use of electric heating (in order to replace the oil heating) increased from 4.3 TWh/year to 28.4 TWh/year. During the same period nuclear power increased from zero to 64.3 TWh/year. Does that mean that "*nuclear power supplied an increasing amount of heating*"? The answer is yes from energy point of view (per year) but does not include the integration cost of electric heating. Figure 8 illustrates how electric heating can vary over a year.

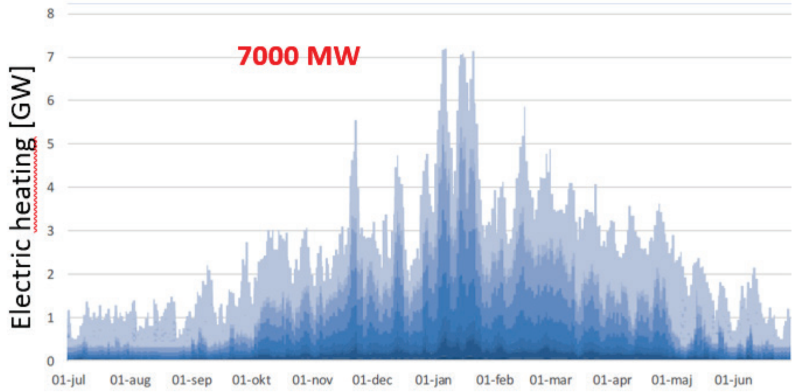

Figure 8 Hourly electric heating in Sweden for the winter 2015-2016 (Axelsson, Blomqvist, & Thomas, 2018)

During 2015-2016 the electric heating was around 19 TWh/year. What is shown in Figure 8 and the historical data from 1970-1987 is that "*integration of electric heating*" requires much more investments than only a yearly energy. There is also a need of power plants to be used in peak load situations, and power lines to feed all houses when it is very cold. So one could certainly claim that there is an "*integration cost of electric heating*".

The same happens currently when there is a significant increase in electric vehicles. These will require not only a certain amount of energy per year, but also power plants, grid investments and balancing if all EV owners want to charge at the same time. So one could certainly claim that there is an "*integration cost of electric vehicles*".

The idea of assigning an "*integration cost*" (Ueckerdt, Hirth, Luderer, & Edenhofer, 2013) is to estimate the "*extra cost*" that is imposed on a system when resource **X** is replaced with resource **Y**, c.f. Figure 9. An "*integration cost*" can refer to a change on the production side, but also, as illustrated above, a change on the consumption side. One can, e.g., compare **X** = 10 TWh nuclear power with **Y** = 10 TWh wind power. Or **X** = A power system with a 10 TWh consumption of hydrogen, no storage with **Y** = A power system with a 10 TWh consumption of hydrogen but with a storage. The question is then what happens with the remaining system, i.e., operation of the other power plants, use of grid and changes in balancing costs.

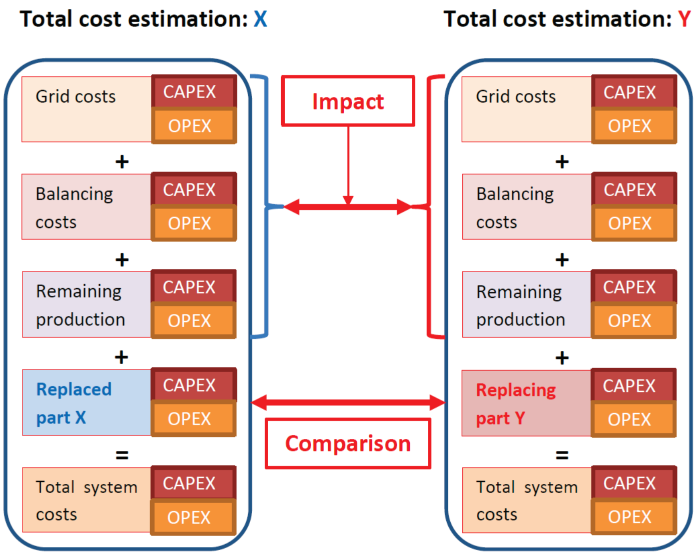

Figure 9 The "integration cost" is the change in other costs when resource X is replaced with resource Y

In (Ueckerdt, Hirth, Luderer, & Edenhofer, 2013) they define the "*integration costs*" as (page 68) "*Integration costs of VRE are the additional costs in the residual power system that VRE impose compared to an ideal benchmark*". This could be done not only for VRE but for any power plant. Here the "*residual power system*" is the remaining part of the system, i.e. Grid + Balancing + Remaining production in Figure 9. An important issues is "*what is the benchmark?*". The ideal benchmark (when a change in the production system is studied) is a technology that follows load (not a flat profile) (Müller, o.a., 2018).

In (Ueckerdt, Hirth, Luderer, & Edenhofer, 2013) they define a method, and they also state (page 63): "*With this expression integration costs and System LCOE can be determined with any power system model that can estimate system costs with and without VRE. Moreover this concept can be applied for estimating integration costs of not only VRE but also any technology. The corresponding base case would change accordingly to a without that technology case*".

The set-up is applied and illustrated in the previous subsection 2.2.2 Example 2: NEA-IEA study. The set-up is there to divide the "*integration cost*" to

- Profile cost = Change of costs in remaining system (not balancing + grid)
- Balancing costs = Change of balancing costs
- Grid costs = Change of total grid cost

where these costs are defined as the difference between two scenarios. The idea is to compare, e.g., 10 TWh of source A with 10 TWh in source B and then spread out the whole integration cost on the 10 TWh of source B and in this way be able to compare LCOE(source A) with LCOE(source B) + [integration cost of source B]. However, there are several challenges of how to apply this in reality, and how to interpret the results. There are certainly different total costs in alternative A and B but a first question is then how these scenarios are defined (c.f. chapter 2) and then how to compare them since one often has several changes between the alternatives.

Below there are some general comments to the set-up and in section 4.6 there are some numerical examples concerning the impact of details on calculation of the "*profile costs*".

3.1 CHALLENGES CONCERNING INTEGRATION COST FOR ONE SPECIFIC CHANGE

Now assume that we want to compare:

- **X** = A power system with a 10 TWh consumption of hydrogen, no storage
- **Y** = A power system with a 10 TWh consumption of hydrogen but with a storage.

The "*integration cost*" is then the impact of the rest of the system (production change = "*profile cost*", grid, balancing) if there is a storage or not in this specific study. One can, in general, state that there is a "*system value*" of having a large storage, or a "*system cost / integration cost*" of not having this storage. There is, however, a rather strong relation between this "*integration cost*" (or "*system value*") and how the "*total system cost*" is estimated. As shown in Figure 9 the integration cost is the difference between 2 estimations of "*total system cost*", which means that how this is calculated, as shown in section 2, for the 2 cases has a large impact on the result of the difference between them. Some impacts are, e.g.,

a) **System cost calculation method impact**: Is the whole system (production, grid, balancing) optimized for both cases? There are many options concerning, e.g., have the same grid in both cases, same production etc.

b) **Calculation order impact**: Assume that the "*base case*" is **X**="*without storage*". Then there must be enough capacity that is built to be able to feed the high demand during peak load. If we then see what happens if we "*add storage*" (to move to **Y**), then all this "*peak units*" will not be used (but they exist). Now we instead assume that "*base case*" is **Y**="*with storage*". If we now see what happens if we "*take away storage*" (to move to **X**), then we probably have to build more capacity to cover the peak demand. This results in a significant "*integration cost*" if we do not have the storage. This means that the way we make the calculations has an impact on the "*integration cost*" or "*extra value*".

c) **Integration cost allocation**: In this specific case it is rather easy to state "*who causes the integration cost*" since we compare with and without a storage. However, as shown in the previous point, it matters how the calculations are made, i.e., which is the base case, and which resources are available in both cases. This means that details are important, i.e., one cannot scientifically state that "*this is the integration cost of not having a storage*", since the used method has an impact on the result. In the beginning of this section, there was a discussion on electric heating and vehicles. If there is "*lack of power to meet the peak*", then "*who caused the problem*"? Is it "*lack of storage*", "*electric heating*" or "*electric vehicle charging*"?

d) **Market impact**: An important issue is to which extent the market reflects the "*integration cost*" or "*extra value*". In this specific case, the hydrogen user certainly has a value of the storage. If, e.g., "*peak capacity*" is needed, when the storage is not available, then there will be high prices in this situation. With a storage one can also trade to lower prices, sell system services etc. So if the market will reflect the "*true value*" of the storage, then the cheapest solution will come "*automatically*" by the "*market invisible hand*". However, a "*perfect market*" is not so easy to design.

3.2 CHALLENGES CONCERNING INTEGRATION COST AT SEVERAL CHANGES

We now go back to the original definition in (Ueckerdt, Hirth, Luderer, & Edenhofer, 2013): "*Integration costs of VRE are the additional costs in the residual power system that VRE impose compared to an ideal benchmark*". Here the "*residual power system*" is the remaining part of the system, i.e. Grid + Balancing + Remaining production in Figure 6.

However, they do not consider how to allocate the integration cost to different actors when there are several changes. In reality, there are a lot of developments in the society that goes on in parallel and when there are many possible choices for the future, then the question is how to split a changed system cost among possible causes. There are different types of new sources, different types of flexible consumers, different types of loads that causes different types of, e.g. flexible and/or peak generation. Table 5 shows some examples.

Table 5 Possible options to choose between for a future power system.

Set-up	Alternative A	Alternative B
a)	50 TWh wind power	50 TWh nuclear power
b)	30 TWh on-shore wind power	30 TWh off-shore wind power
c)	15 TWh electric heating/heat pumps	15 TWh district heating
d)	20 TWh wind power	20 TWh solar power
e)	Hydrogen use in industry with storage	Hydrogen use in industry without storage
f)	10 TWh EV:s, controlled charging	10 TWh EV:s with free charging
g)	15 TWh new computer centers	No new computer centers
h)	Free international trading also for system balancing	Specific requirements per country concerning all system balancing.

A question is then how to handle "*integration costs*" when there are several options to choose between. Which option does then cause which cost? We will here go through two examples to illustrate this.

3.3 EXAMPLE 1: CONSEQUENCE OF TWO CHANGES

This example comes from (Ueckerdt, Hirth, Luderer, & Edenhofer, 2013), Figure 6 on page 67, c.f. Figure 10. It can be noted that this figure is very close to Figure 4 which depends on that the corresponding report (OECD/NEA, 2019) bases its analysis on (Ueckerdt, Hirth, Luderer, & Edenhofer, 2013). If one studies this illustration and the text below, it is the clear that the VRE "*caused*" an integration cost but this is then "*decreased*" thanks to "*flexibility options*". But still the interpretation is that it was the VRE that caused this. The set-up in the figure is that there is first "*no flexibility*" (denoted "*short-term integration cost*") and after a while this is decreased (when "*Integration options*" are introduced"). But is this really logical? Don't these things happen at the same time? Or what happens first?

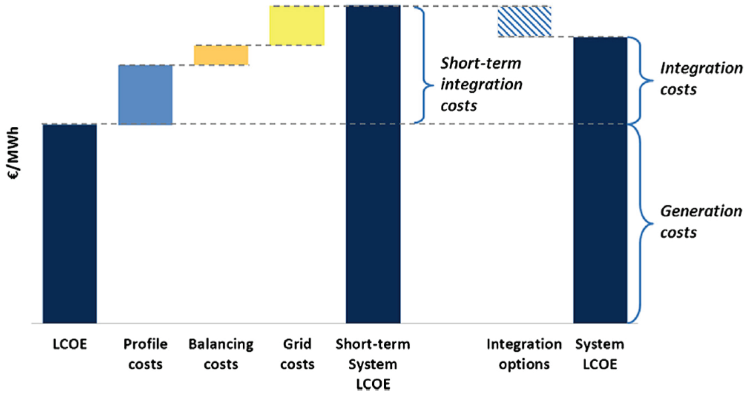

Figure 10 Example 1a = Fig. 6 in (Ueckerdt, Hirth, Luderer, & Edenhofer, 2013): "Integration costs are divided into three components: profile, balancing and grid costs. To some extent integration costs that occur in the short term can be reduced by integration options in the long term."

Now assume that the "timing" is changed. The result is shown in Figure 11. The background is then the following: First one made a study where it was assumed that some flexibility was implemented, e.g. hydrogen storage in industry, flexible electric heating, or flexible charging in Electric Vehicles. But then, in a new estimation, the question was what the consequence is if this flexibility was not implemented, or indirectly "*the value of this flexibility*". The result was that the total system cost (denoted "*System LCOE*") increased.

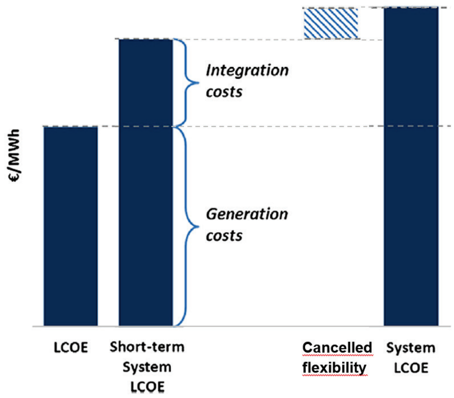

Figure 11 Integration cost for example 1b. First the impact of more VRE including available flexibility was studied, and then the impact of very little flexibility was estimated.

So which source "*caused*" the increase in the last step? What is shown here is that the order of how different changes are considered has an impact on which resource that "*causes an integration cost*". The same question comes up if, e.g., one introduces both wind power and solar power. Which source should be integrated first? And why?

3.4 EXAMPLE 2: CONSEQUENCES OF FIVE CHANGES.

In this case we study the integration cost when we compare 2 systems which are shown in Table 6. The case is close to current discussions/planning/forecasts in Sweden. 15 TWh of Electric vehicles is what is the result if all personal cars become electric, and then there is a discussion whether they will be flexible or not. The Hybrit project is a project with the idea to use electricity to produce hydrogen, which can replace coal in the steel industry. The yearly consumption, if this is implemented, is in its first step around 15 TWh. However, there is a discussion concerning a suitable size of a hydrogen storage, which will then have an impact on the flexibility in the system. There will certainly be more wind power in Sweden, but there is a discussion concerning estimation of remaining life length of current nuclear power stations and if new reactors are needed.

Table 6 Different systems in Example 2 for estimation of integration costs.

	Base case	Studied five changes
Nuclear power TWh/year	50	20
Electric Vehicles 15 TWh/year	Flexible	Not flexible
Hybrit project 15 TWh/year	Flexible	Not flexible
Wind power TWh/year	50	80 (+30 TWh)
Transmission system	Strong for +30 TWh wind power	Not strong for +30 TWh wind power

In Table 6 there are now two different cases. We first have a base case and then a studied future scenario with five different changes. What might be of interest is then to split up the "*integration cost*" between the different changes. As stated in (Ueckerdt, Hirth, Luderer, & Edenhofer, 2013) and cited above: "*Moreover this concept can be applied for estimating integration costs of not only VRE but also any technology. The corresponding base case would change accordingly to a without that technology case*". However, the procedure for how to do this can be made in different ways. If the idea is to allocate the integration cost to different technologies, then one has to insert the technologies step-wise. Below this is done in two different orders which are shown in Figure 12 - Figure 13.

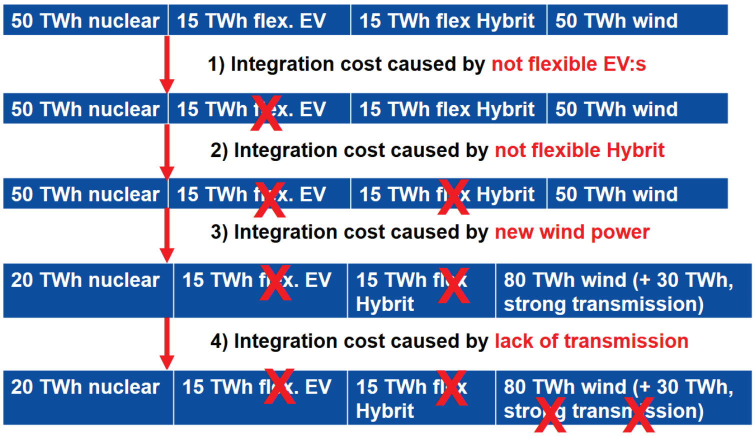

Figure 12 Example 2a for how the integration cost is allocated to different actors

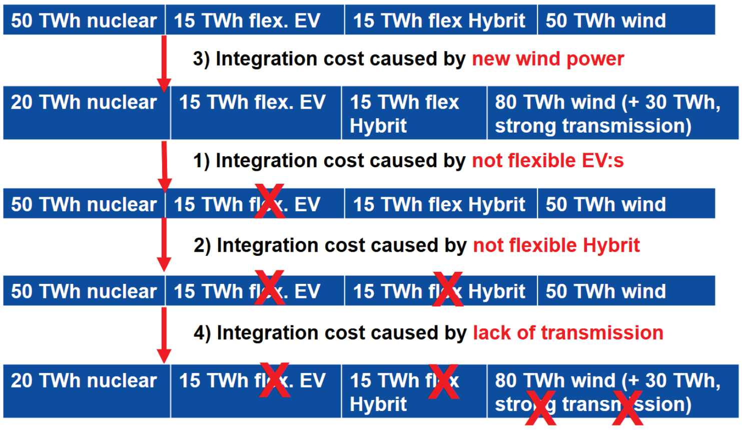

Figure 13 Example 2b for how the integration cost is allocated to different actors

We can now compare the two different set-ups. First it has to be noted that the first set-up (top row) is the "*base case*" according to Table 6 in both versions, and also the final set-up (last row) is the "*studied five changes*" from Table 6 in both cases. If we take one specific example, i.e. the integration cost of new wind power. In Example 2a there is no flexibility in EV:s or Hybrit when wind power was introduced, while in Example 2b all the flexibility remains. This means that the "*integration cost of wind power*" will probably be significantly higher in example 2a than in Example 2b. The sum of all integration costs should be the same in both cases since the total system cost changes as much. But the allocation depends on the calculation order. This means, in reality, that there is **not a clear definition of the "*integration cost*"** for a certain technology since its level, with the suggested definition in (Ueckerdt, Hirth, Luderer, & Edenhofer, 2013), completely depends on how one applies the method.

4 System and integration cost numerical examples

In this section, we will present some different set-ups and consequences concerning impact from assumptions on *system costs* and *integration costs*. The examples only consider the production part, i.e. not the grid or balancing part. There are, however, important issues to reflect on such as use of optimization, fundamental assumptions, profile costs, remaining system etc. The example is not reflecting a Swedish or any other system, but is used to illustrate the impact from assumptions. A comparatively small system set-up is used which makes it qualitatively illustrative, but at the same time it is too simple to draw any quantitative conclusions.

The idea is **NOT** to draw any numerical answers, but just to show the impact from different assumptions.

4.1 CASE 1: BASE SYSTEM

The base system consists of a 200-hour period where there is a balance between total production and demand during each hour. There is no link between the hours so each hour is treated separately from the other hours. The used program is an Excel program explained in (Söder L. , 2017). The benefit of this program is that it is easy to select periods and data as well as applying various types of optimization.

The base system and its parameters are shown in Table 7. The Investment and operation cost of wind (mean value) and nuclear (medium value) are taken from (Qvist Consulting Ltd, 2020) (Qvist Consulting Ltd, 2020) and the remaining data are from (Söder L. , 2017). The operation cost for nuclear is slightly higher than in (Qvist Consulting Ltd, 2020) but on the other hand, the availability is set to 100%. For CO2 we have used 80 EURO/ton taken from "2040-high scenario" in (Svenska Kraftnät, 2019)-page 18.

Table 7 Basic system with assumption of 10 SEK/Euro and a CO2 cost of 80 EUR/ton.

Source	Investment cost		Life time	Interest	CO2	CAPEX		OPEX
	SEK/kW	EUR/kW	years	rate	kg/kWh-el.	Eur/MW, year	EUR/MW, period	EUR/MWh
Wind-onshore	10000	1000	20	6%	0,00	116485	2659	0,0
Nuclear	58000	5800	50	6%	0,00	420278	9595	15,3
Gas-OCGT	4600	460	25	6%	0,51	42424	969	110,5
Gas-CC	7000	700	25	6%	0,35	65858	1504	78,7
Coal-cond.	16000	1600	25	6%	0,71	160445	3663	79,4

In the used software one defines 3 periods per year for demand and wind power. The set-up here is to model every second hour starting with 3 different dates. We have selected one winter period, one summer period and one autumn/spring period. The load data are taken from Sweden, year 2015. Concerning wind power, the dates were selected in order to get the distribution as close as possible to the distribution during the whole year. The result is shown in Figure 14.

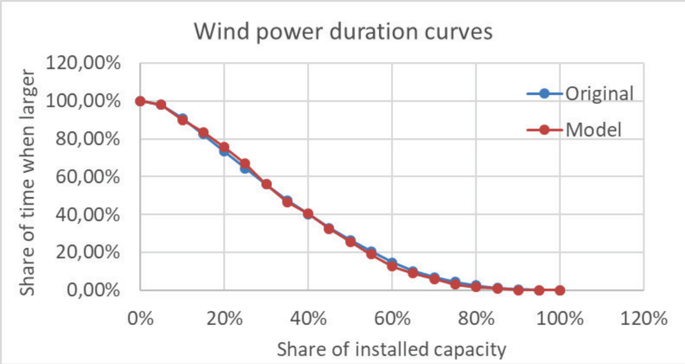

Figure 14 Duration curve for yearly wind power and simulated wind power during 200 hours. The capacity factor for wind power is 35.9%. This is based on that the maximum production = installed capacity. In, e.g., (Qvist Consulting Ltd, 2020) is the wind power capacity factor assumed to be 36.5%.

The selected periods are shown in Table 8.

Table 8 Selected periods during 2015 for the simulation. Starting 00.00 each day, then every second hour is modelled

Period	Start date for demand	Start date for wind	Number of hours
Winter	2015-01-22	2015-02-27	60
Summer	2015-06-29	2015-06-25	40
Spring/autumn	2015-04-10	2015-10-30	100

The program then calculates the cheapest operation during each hour, when means a merit order method and starts with the power plant with the lowest operation cost, and fill up to the demand with increasing operation cost. The operational cost of the marginal unit then sets the power price (marginal cost pricing). This technically means a perfect market and an energy only market. There are no outages in the thermal power stations, so they can be used all hours. The resulting operation per hour is shown in Figure 15.

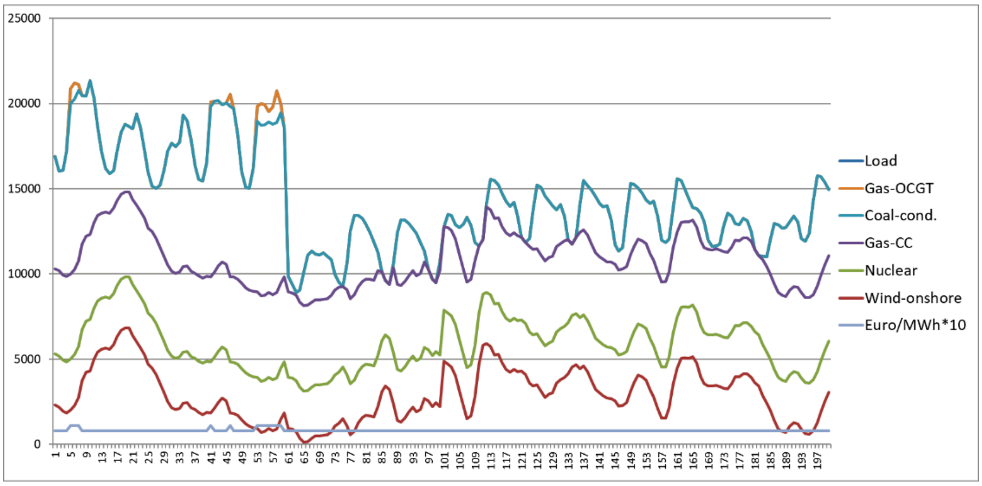

Figure 15 Case 1: Operation per hour for base system. The figure shows the production in each source in addition to the previous source and in increasing operation cost order. Nuclear power has, e.g., a constant production. The fast "ramp" in hour 60 is not a "ramp" but refers to a change in period, from winter to summer, c.f. Table 8.

The results in Figure 15 are based on an assumed amount of capacity for each source. These assumptions as well as numerical results are shown in Table 9.

Table 9 Case 1: Assumptions on capacity per source and results.

	Capacity	Energy		CAPEX	OPEX	Total cost	Revenue	LCOE	Value
Source	MW	MWh	%	kEUR	kEUR	kEUR	kEUR	EUR/MWh	EUR/MWh
Wind-onshore	8000	573750	20%	21276	0	21276	46020	37,08	80,21
Nuclear	3000	600000	21%	28786	9180	37966	48697	63,28	81,16
Gas-OCGT	3000	10516	0%	2906	1162	4067	1162	386,79	110,46
Gas-CC	5000	987994	34%	7518	77737	85255	80217	86,29	81,19
Coal-cond.	10000	703961	24%	36631	55860	92492	59594	131,39	84,65
Total	29000	2876221	100%	97117	143939	241056	235689	83,81	81,94
Mean price:		81,2	EUR/MWh						
Mean consumer price:		81,9	EUR/MWh						

Some comments are:

a) The LCOE (Levelized cost of energy) is calculated as total cost during the period (CAPEX and OPEX) divided with energy production.

b) The Value is calculated as that the power is sold to the market price = system marginal cost.

c) There are no curtailments of wind or nuclear power as shown in Figure 15.

d) For wind and nuclear the value is significantly higher than the cost.

e) One challenge with this method is that the peak power, Open Cycle Gas Turbines - OCGT, can NOT be profitable since it is assumed that the income for this plant comes from the power price which is then set by the marginal cost in this plant. So only the OPEX is covered, not the CAPEX for this plant.

f) None of the fossil plants gets their costs covered.

g) The "*mean price*" is the mean value of the 200 prices. The "*Mean consumer price*" is the payment for the average MWh. These 2 prices are close but not the same since there is higher consumption at higher prices.

h) Nuclear has a slightly higher value than wind power.

i) With the assumed CO2 price and other prices, the Combined Cycle Gas Turbine – CCGT will get a lower operation cost than coal power.

4.2 CASE 2: VALUE IMPACT FROM CHANGE IN CO2 COST AND AMOUNT OF WIND POWER

The aim of this test case is to see what happens with different issues when the cost of CO2 changes or the amount of wind power changes. The method is the same as above, but the difference is that we just change these two parameters. We only study the result for wind power and nuclear. The results are summarized in Table 10 - Table 11.

Table 10 Cases 2a-2c: Changes in value and LCOE, [EUR/MWh], at changed CO2 prices. Wind: 8000 MW.

	C1: Base case		C2a: CO2: 100 EUR/ton		C2b: CO2: 60 EUR/ton		C2c: CO2: 40 EUR/ton	
Mean price	**81.2**		**94.5**		**68.4**		**55.8**	
	LCOE	Value	LCOE	Value	LCOE	Value	LCOE	Value
Wind	37.1	80.2	37.1	93.5	37.1	67.2	37.1	54.2
Nuclear	63.3	81.2	63.3	94.5	63.3	68.4	63.3	55.8

For the case with 20000 MW of wind power, the detailed result of the operation is shown in Figure 16.

Table 11 Cases 2d-2f: Changes in value and LCOE, [EUR/MWh], at changed amount of wind power. CO2 price: 80 EUR/ton.

	C1: Base case	C2d: Wind: 12000 MW			C2e: Wind: 16000 MW			C2f: Wind: 20000 MW		
Mean price	**81.2**	**80.1**			**77.4**			**66.5**		
	Energy	LCOE	Value	Energy	LCOE	Value	Energy	LCOE	Value	Energy
Wind	20%	37.1	79.3	30%	37.1	75.5	40%	37.2	57.3	50%
Nuclear	21%	63.3	80.1	21%	63.7	77.9	21%	67.4	71.2	19%

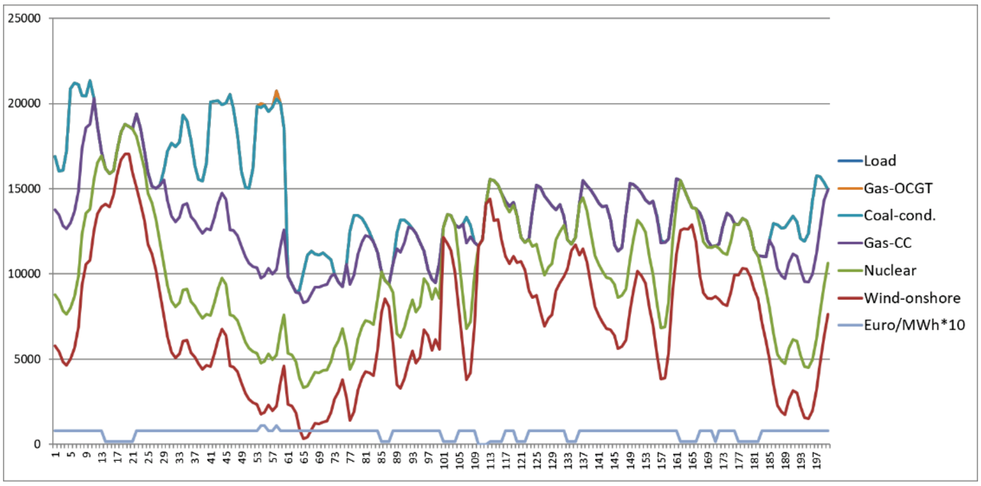

Figure 16 Case 2f: Power plant operation in the case with 20000 MW of wind power.

<u>Some comments are:</u>

a) Changed CO2 price has an impact on how profitable the different sources are. At the lowest CO2-price, 40 EUR/ton, is the nuclear power (with assumed costs) not profitable.

b) The difference in value for wind and nuclear power is only changing slightly (from 1 EUR/MWh to 1.6 EUR/MWh] between the different assumptions of CO2 costs.

c) When the amount of wind power increases, then also the LCOE increases slightly for both wind power and nuclear. This depends on that the utilization time decreases since not all available capacity could be used.

d) At the largest amount of wind power, 20000 MW (50% of energy production), the prices will vary between OCGT operation cost and nuclear operation cost. This will increase the interest of flexibility, which is not considered in the available model.

e) More wind power decreases the power price with the assumed set-up. This will then decrease the value of any power source, but with the here assumed prices, wind is still profitable.

4.3 CASE 3: OPTIMIZED SYSTEM

In Case 1-2 there was an assumption of a specific amount of capacity in each source. The set-up in Case-2 where wind power was increased can be classified as a "*brown-field*" since the other sources are assumed to be the same, no matter the amount of wind power.

In this Case-3 we assume, instead, that we want to minimize the total cost of the system and the program should select the cheapest combination of all sources when the amount of wind power increases. We do not have a "*CO2-target*" but we assume the same CO2 cost as above, i.e., 80 EUR/ton. As stated in the basic set-up Case-1 the total cost for the simulated period was 241056 kEUR for both OPEX and CAPEX, c.f. Table 9. The optimization result is shown in Table 12 and the operation for each hour is shown in Figure 17.

Table 12 Case 3a: Combination of power plants in order to get the lowest total cost.

	Capacity	Energy		CAPEX	OPEX	Total cost	Revenue	LCOE	Value
Source	MW	MWh	%	kEUR	kEUR	kEUR	kEUR	EUR/MWh	EUR/MWh
Nuclear	3000	410419	14%	28786	6279	35066	30433	85,4	74,2
Wind-onshore	25975	1785348	62%	69080	0	69080	65971	38,7	37,0
Gas-OCGT	5695	47153	2%	5516	5209	10725	5209	227,4	110,5
Gas-CC	9122	633302	22%	13716	49829	63545	55048	100,3	86,9
Coal-cond.	0	0	0%	0	0	0	0	-	-
Total	43792	2876221	100%	117098	61318	178416	156660	62,0	54,5
Mean price:		52,3	EUR/MWh						
Mean consumer price:		54,5	EUR/MWh						

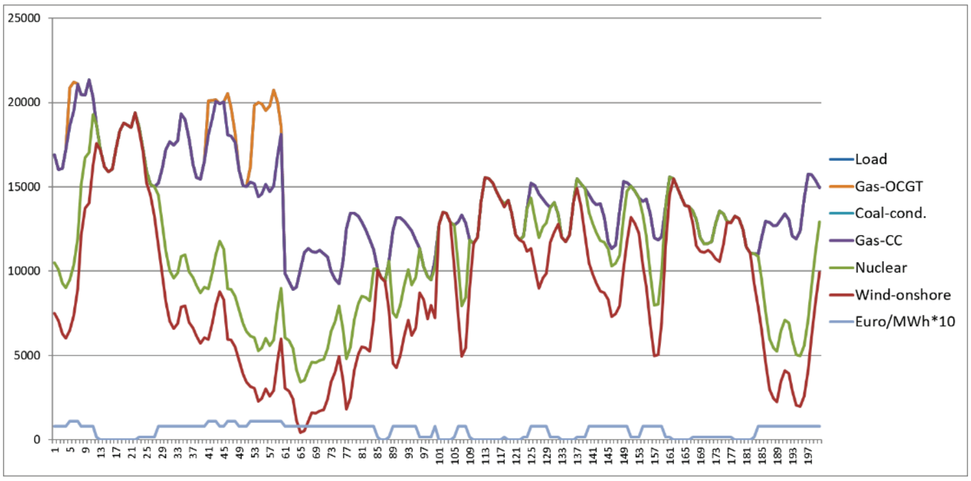

Figure 17 Case 3a: Operation during simulation period with capacities as in Table 12.

Some comments are:

a) The optimization led to that the total cost decreased from 241056 kEUR to 178416 kEUR, i.e. a decrease with 26%,

b) An "*optimization*" approach implies that the whole planning up to the future date is directed towards this set-up and that the prices reflect reality.

c) An "*optimization*" where "*cost*" is minimized (as in this example) is NOT the same as that this power system will be built in an energy only market. If one studies Table 12, then it is, e.g., obvious that none of the sources are profitable (lower value than LCOE). In optimization the selection between wind and the other sources is that the marginal cost/value (extra investments) of these sources should be the same.

d) From Table 12 one can see that LCOE for wind power is higher than previously (38.7, earlier around 37.1 EUR/MWh), but much higher for nuclear (85.4 EUR/MWh). This depends on, which can be seen from Figure 17, that all nuclear capacity is not always used. Also wind power is sometimes curtailed since in the cases when only wind power is used, then it is curtailed down to the demand level. This example also shows the simplified assumption since there are situations when there is 100% wind power in the power system. This may be technically possible, but requires a technical development compared to today, and also specific system services.

e) The price is now significantly lower than earlier, but this also causes that the power plants are not profitable.

As shown in Table 12 wind power is not profitable. One can assume that wind power is only built if the investment at least get the payment back from the market price. One can then, in the optimization, set a limit that wind power is only built if the investment is profitable. The result with this assumption is shown in Table 13.

Table 13 Case 3b: Result when optimization set-up requires that wind power is profitable.

	Capacity	Energy		CAPEX	OPEX	Total cost	Revenue	LCOE	Value
Source	MW	MWh	%	kEUR	kEUR	kEUR	kEUR	EUR/MWh	EUR/MWh
Nuclear	3000	433656	15%	28786	6635	35421	32121	81,7	74,1
Wind-onshore	24875	1730938	60%	66155	0	66155	69172	38,2	40,0
Gas-OCGT	6196	58216	2%	6002	6431	12433	6431	213,6	110,5
Gas-CC	8750	653378	23%	13157	51409	64566	57527	98,8	88,0
Coal-cond.	1	32	0%	5	3	8	4	245,9	110,5
Total	42824	2876221	100%	114106	64477	178583	165255	62,1	57,5
Mean price:		55,4	EUR/MWh						
Mean consumer price:		57,5	EUR/MWh						

Some comments are:

f) Wind power is now profitable since the value is higher than the LCOE. But the value is still lower than for the other power sources.

g) The other power sources, nuclear, gas-OCGT and gas-CC, are still not profitable.

h) The amount of wind power has decreased from 25975 MW to 24875 MW, i.e. -4%.

i) The mean power price has increased from 52.3 to 55.4 EUR/MWh, i.e. +6%.

4.4 CASE 4: CONCERNING RELIABILITY AND PRICE-DEPENDING DEMAND.

In Cases 1-3 the power plants have always managed to cover the peak. However there are then two possible changes to this:

1) One could assume that there is a limited reliability/adequacy, i.e. the demand is not always met. However, this is normally modelled as a "*curtailment plant*" with the VOLL-cost (= Value of Lost Load). What is then essential is if this cost is reflected as the market as the "*market price*" or not. If not, then there must be some kind of model/description of how the price is formed during load curtailments.

2) One could assume that at very high prices the demand will decrease. One can then assume that this "*flexible demand*" bids in to the market so the price is set by the needed price for the consumption decrease.

These set-ups can be modelled in the same way as a "*production resource*" at a certain cost. In this way, the market price is set by the cost of this. We now make a small modification of the base case: We reduce the amount of OCGT shown in Table 9, 3000 MW, to 1300 MW. This is then enough, so during 2 hours (1% of 200 hours) curtailments are needed. It is here assumed that the cost for this (VOLL of bid-price for curtailment) is 2000 EUR/MWh. The result is shown in Table 14.

Table 14 Case 4a: Assumptions on capacity per source and results.

	Capacity	Energy		CAPEX	OPEX	Total cost	Revenue	LCOE	Value
Source	MW	MWh	%	kEUR	kEUR	kEUR	kEUR	EUR/MWh	EUR/MWh
Nuclear	3000	600000	21%	28786	9180	37966	60034	63,3	100,1
Wind-onshore	8000	573750	20%	21276	0	21276	49058	37,1	85,5
Gas-OCGT	1300	9980	0%	1259	1102	2362	6015	236,6	602,7
Gas-CC	5000	987994	34%	7518	77737	85255	99112	86,3	100,3
Coal-cond.	10000	703961	24%	36631	55860	92492	97384	131,4	138,3
Curtailments	536	536	0%	0	1072	1072	1072	2000,0	2000,0
Total	27836	2876221	100%	95471	143880	240422	311604	83,6	108,3
Mean price:		100,1	EUR/MWh						
Mean consumer price:		108,7	EUR/MWh						

The operation of the system according to Table 14 is now shown in Figure 18.

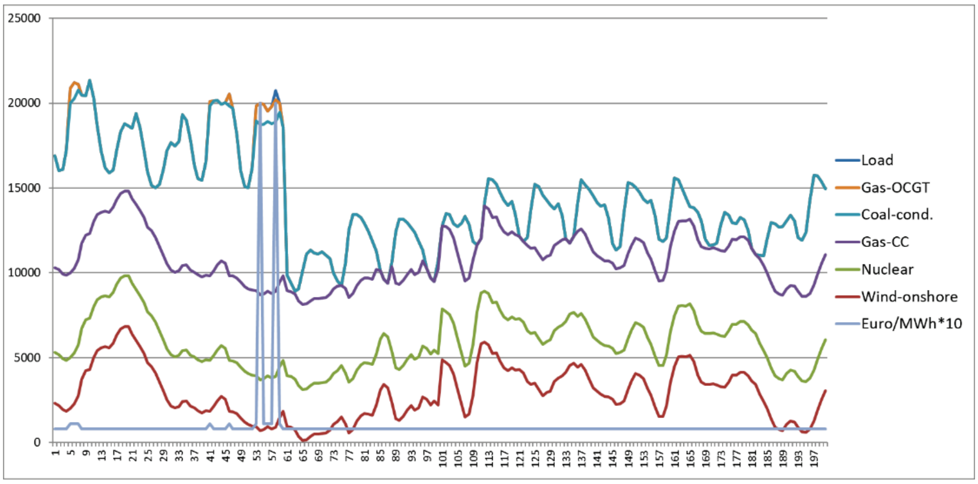

Figure 18 Case 4a: Operation per hour per source for

Some comments are:

a) There are 2 hours when capacity is not enough. In these hours the power price becomes very high and is set by the assumption of the curtailment price. As shown this happens when the wind power has a comparatively low production level.

b) One can now identify the impact from these high prices by comparing the results in Table 14 with the base Case-1 results in Table 9. The mean price will, e.g., increase from 81.2 EUR/MWh to 100.1 EUR/MWh.

c) The value for nuclear power increases as the increase of mean price: From 81.2 to 100.1 EUR/MWh. But for wind power the increase is much smaller: From 80.2 to 85.5 EUR/MWh which depends on the high prices only happens during low wind power.

d) With these high prices the OCGT will now move from not profitable (in Table 9) to profitable (in Table 14). This shows the importance of that the demand bid pricing limits problem of that peak units cannot be financed in an energy only market.

e) Also coal power and CCGT now become profitable.

We now apply an optimization as in Case-3b. This means that we now allow curtailments as an option and that we have the requirement that wind power should be profitable (Value > LCOE). The result is shown in Table 15 and the operation per hour is shown in Figure 19.

Table 15 Case 4b: Optimal amount of wind power when curtailments are allowed.

	Capacity	Energy		CAPEX	OPEX	Total cost	Revenue	LCOE	Value
Source	MW	MWh	%	kEUR	kEUR	kEUR	kEUR	EUR/MWh	EUR/MWh
Nuclear	3000	421890	15%	28786	6455	35241	36847	83,5	87,3
Wind-onshore	25399	1757789	61%	67549	0	67549	73734	38,4	41,9
Gas-OCGT	5351	42345	1%	5183	4678	9860	14788	232,9	349,2
Gas-CC	9517	654193	23%	14310	51473	65784	74297	100,6	113,6
Coal-cond.	0	0	0%	0	0	0	0	-	-
Curtailments	4	4	0%	0	7	7	7	2000,0	2000,0
Total	43271	2876221	100%	115828	62606	178441	199665	62,0	69,4
Mean price:		63,4	EUR/MWh						
Mean consumer price:		69,4	EUR/MWh						

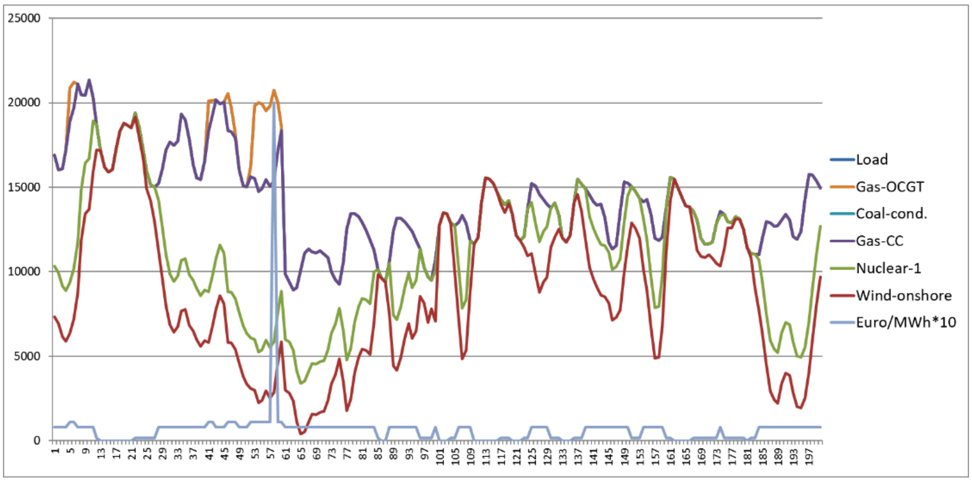

Figure 19 Case 4b: System operation at optimal amount of wind power when curtailments are allowed.

Some comments are:

f) It can be noted that the optimization is not "*exact*". A so-called "*evolutionary method*" is used to get the results, which is not an exact method.

g) There is 1 hour when capacity is not enough. In this hour the power price becomes very high and is set by the assumption of the curtailment price, 2000 EUR/MWh. As shown this happens when the wind power has a comparatively low production level.

h) The whole set-up is based on that the "*curtailment price*" is transferred to the market. If this is not the case, then the value of the different sources are not affected by the curtailments.

i) The mean price increases from 55.4 to 63.4 EUR/MWh depending on the significantly higher price during one hour. 2000 EUR/MWh during one hour increases (compared to zero) the mean price during 200 hours with 10 EUR/MWh.

j) We now get more wind power, 25399 MW instead of 24875 MW (+2%), since the price is higher and there is a requirement on that wind power should be profitable.

k) Also the other power sources, nuclear, Gas-CC and Gas-OCGT now become profitable compared to when these high prices did not occur.

l) It has to be mentioned that 1 hour of curtailments during a 200 hour period corresponds to 0.5% of the time. For the whole year this means around 45 hours/year which is probably much higher than what would be acceptable.

m) With this very high amount of wind power, different kinds of storage and/or flexible demand will be very interesting. In Figure 19 there are 33 hours with power price = 0, i.e. wind power marginal cost (=0) is setting the price. This means 16.5% of the time. If this would happen in reality then the consumption would increase and thereby the price.

4.5 CASE 5: CONCERNING IMPACT FROM STORAGE

Storage can be of several types and in several parts of the whole system, as shown in section 2.3.4. Here we will use a simplified modelling of the storage possibility. Storage, formally, means that power consumption is decreases compared to a certain level and then increased in another situation. One can, e.g., cool down a heated house and then reheat it later. In this case the decreased consumption comes before the increase.

The method used here is to, per sub-period (see Table 8), **1:** Assume a certain storage capacity [MW], $P_{storage}$. **2:** Assume also a P_{limit}. **3:** At higher net-demand (demand minus wind power) that P_{limit}, decrease the consumption with $P_{storage}$ but not lower than P_{limit}: At lower net-demand than P_{limit}, increase the demand with $P_{storage}$, but not higher that P_{limit}. **4:** Assign P_{limit} so the amount of demand increase is the same as demand decrease during each sub-period. As seen in this model there is no data on size of storage etc. There are several possibilities of different types of storage, which have different impacts on the performance. Some can reach for weeks-seasons (hydro storage), while other-ones only have capacity for hours/days (building heating). One storage example is the Swedish Hybrit project where the idea is to make steal without using coal and instead use hydrogen. The plan is around 1700 MW of electrolysis capacity and 5 days hydrogen storage. Another type of storage is Electric Vehicles. Depending on battery size, an electric vehicle can sometimes only be charged only once a week.

We will here illustrate the impact of storage using the high wind case 2f. The hourly operation is shown in Figure 20. It can be noted that this figure is drawn in a slightly different way.

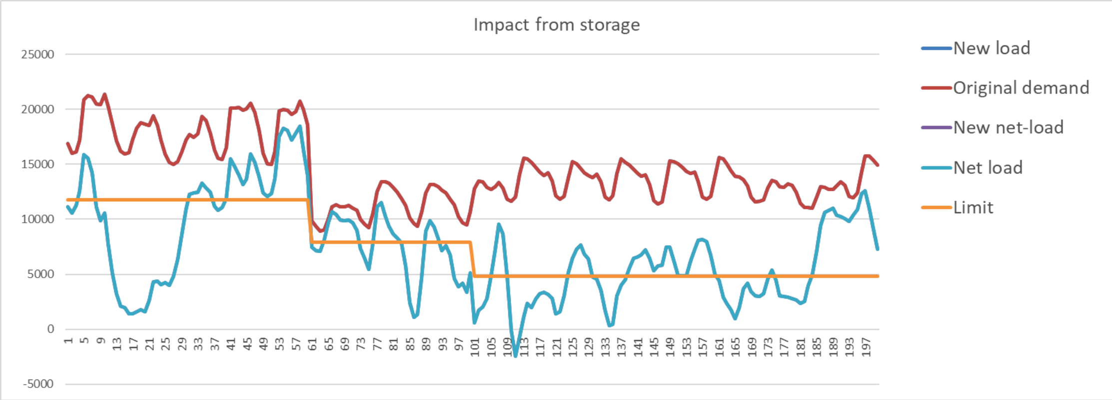

Figure 20 Hourly operation for case 2f which is the base case with CO2 cost of 80 EUR/MWh and 20000 MW wind power

Here we have the wind at the top so the blue curve, the Net load, is what should be served by the other power plants. We now introduce 2000 MW of "*storage capability*". This means that in each of the three periods the demand will increase when the net-load below P_{limit} and decrease when it is higher than this level. In Figure 21 the impact of how the storage is used is shown. It can be noted that during the peak demand there is in this period a comparatively high wind power production. This means that here an efficient use of storage implies that demand is increased during peak demand.

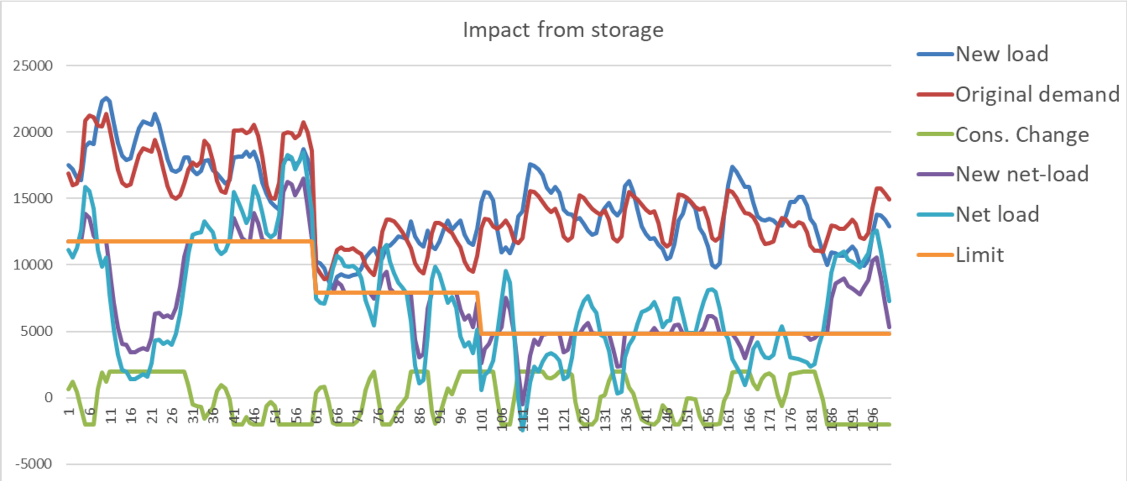

Figure 21 Hourly operation for case 2f but now with a flexible storage demand of 2000 MW

The motivation for the strategy to change the demand in relation to the net-demand change is that this is the most cost efficient way to use the storage. This is shown in Figure 22 which shows duration curves for the same cases as shown above in Figure 20 and Figure 21 respectively.

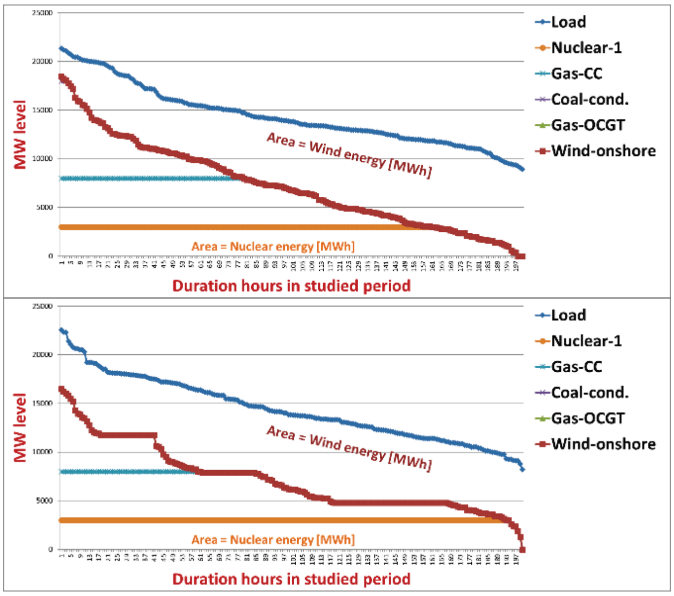

Figure 22 Change of net-demand caused by storage. Left: no storage, Right: 2000 MW storage. It is shown that net-demand decreases with storage although the peak demand increases. It is also shown that increasing net demand leads to higher marginal costs in the system.

There are many impacts when storage is introduced. A summary of results is shown in Table 16.

Table 16 Case 5a: Comparison of different system data for a system with and without

	Without storage	With storage
Wind power [MW]	20000	20000
Wind power [%]	49,8%	49,9%
CO2 cost	80	80
Mean price [EUR/MWh]	66,5	76,6
Storage [MW]	-	2000
Stored energy [MWh]	-	153441
Total cost kEUR	207966	205099
Storage value [EUR/MWh]	-	18,7
Storage market value [EUR/MWh]	-	62,6

There are some issues to comment: As shown in Table 16 the mean price increases when this storage is introduced. The reason is that the number of hours with very low prices (marginal cost zero caused by curtailed wind and/or nuclear) decreases. The "*Stored Energy*" is the sum of all changes in one of the directions (up or down). The "*Storage value*" is the change in total cost divided to all stored energy, i.e. the value of moving one MWh from one hour to another hour. The "*Storage market value*" is the same as "*Storage value*" but it does NOT see the change in total cost, but instead the market price. So the average MWh has a value of 62.6 EUR when it is moved from one hour (with high price) to another one with low price.

The next step is then to compare what happens when we change the amount of wind power or change the size of the storage.

Table 17 Case 5b-5e: Change of storage value when the amount of wind power increases. Table shows the case of 2000 MW of storage while the wind power increases from base case 5b: 8000 MW to 5e: 24000 MW. The case of 20000 is shown in Table 16.

	Without storage	With storage	Without storage	With storage	Without storage	With storage	Without storage	With storage
Wind power [MW]	8000	8000	12000	12000	16000	16000	24000	24000
Wind power [%]	19,9%	19,9%	29,9%	29,9%	39,9%	39,9%	58,6%	59,7%
CO2 cost	80	80	80	80	80	80	80	80
Mean price [EUR/MWh]	81,2	79,4	80,1	79,3	77,4	78,7	54,1	65,3
Storage [MW]	-	2000	-	2000	-	2000	-	2000
Stored energy [MWh]	-	129446	-	138759	-	145447	-	158849
Total cost kEUR	241056	240721	228784	228603	217015	216611	204850	197067
Storage value [EUR/MWh]	-	2,6	-	1,3	-	2,8	-	49,0
Storage market value [EUR/MWh]	-	0,0	-	1,4	-	11,6	-	343,5

Table 17 shows the impact of value of storage when the amount of wind power increases. Especially at around more than an wind energy share of 40% the value increases significantly. It can be noted that at lower amount of wind power the value seems to be very limited. This depends partly on that in each fossil fuel power interval, the marginal cost is the same. This means that when storage is used it may not change the marginal cost so much. But for larger amounts of wind power the marginal cost (= the price) change a lot when wind power changes its production. It is also obvious that storage increases the amount of wind power at, e.g., 24000 MW since storage increases the wind share from 58.6 to 59.7%.

Table 18 Case 5f-5i: Change of storage value when the amount of storage capacity increases. Table shows the case of 20000 MW of wind power while the storage capacity increases from base case 5f: 1000 MW to 5i: 5000 MW. The case of 2000 is shown in Table 16.

	Without storage	With storage	Without storage	With storage	Without storage	With storage	Without storage	With storage
Wind power [MW]	20000	20000	20000	20000	20000	20000	20000	20000
Wind power [%]	49,8%	49,8%	49,8%	49,9%	49,8%	49,9%	49,8%	49,9%
CO2 cost	80	80	80	80	80	80	80	80
Mean price [EUR/MWh]	66,5	71,6	66,5	77,9	66,5	78,5	66,5	78,5
Storage [MW]	-	1000	-	3000	-	4000	-	5000
Stored energy [MWh]	-	87065	-	198611	-	231312	-	257055
Total cost kEUR	207966	206000	207966	204781	207966	204656	207966	204586
Storage value [EUR/MWh]	-	22,6	-	16,0	-	14,3	-	13,1
Storage market value [EUR/MWh]	-	172,7	-	30,7	-	12,3	-	13,4

Table 18 shows the largest value of storage initially and then it decreases at increasing amount of storage. The reason is that storage evens out the price differences which means that the extra value of having more storage decreases.

4.6 CASE 6: INTEGRATION COST AND PROFILE COST EXAMPLES

In this case we will study the impact from the idea of estimating an "*integration cost*" as the proposed "*changed cost in the remaining system*". We will then start in a base system and add 3 changes: 1500 MW offshore wind power, 3500 MW on shore wind power and 3000 MW storage. As will be shown here, there are certain challenges of using this method, which has a large impact of the possibilities to use it. In this example we will only study the impact on the so-called "*profile cost*", since we in this example have no model of the grid or detailed balancing. This means that the "*System LCOE*" is seen as a sum of LCOE and "*integration cost*" according to Figure 23. In this example we only study change in hourly operation, i.e. no estimations of changed grid och balancing costs. This means that, in this example, the "*integration cost*" = "*profile cost*".

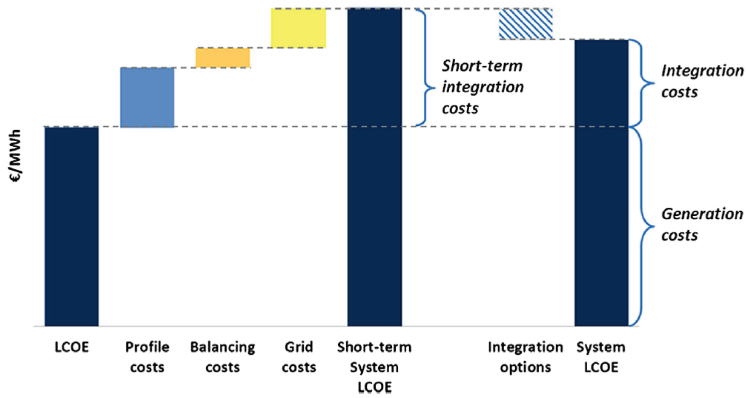

Figure 23 same as Figure 10: System LCOE = LCOE for generation + Integration cost.

However, there are some further assumption/choices, which have to be considered. Assume, e.g., that we have 3000 MW of nuclear power and then we replace 1000 MW of this with wind power. If there is already, from the beginning, a large amount of wind power, then extra wind power may decrease the energy production in the remaining 2000 MW of nuclear power. There are then 2 different ways of handling this:

A. When wind power replaces nuclear production, then the amount of new wind power should be so large so it compensates for decreased energy production in the remaining nuclear power.

B. The decreased nuclear production is instead replaced with other thermal production and this extra energy is considered as a part of the "*profile cost*" of the new wind power.

Another issue is that if there is already larger amount of wind power, then maybe not all new wind power can be used. Also here there are different options:

C. One assumes that there is a fundamental utilization time of new wind power. If not all wind power can be used, it is then compensated with other thermal power, and this extra cost is seen as a "*profile cost*" of wind power.

D. One install so much wind power so the net production comes up to the required level. This means that extra wind power to compensate for curtailments, is NOT a "*profile cost*" but instead an investment cost.

A linked challenge is the assumption of LCOE. This cost is based on the investment cost and a certain utilization time of a source, e.g. nuclear power or wind power. At low capacity in these sources, all available capacity will often be used. But when wind power, or nuclear power, increases then the utilization time will decrease which implies an increased LCOE. So the question is which LCOE one should use. Alternatives include:

E. Use the basic LCOE at low penetration of wind of nuclear power. This means that all available capacity is assumed to be used.

F. Use the actual LCOE in the start system. In today's power system it is not uncommon that there is already such a large amount of wind or solar power, so all available power is not used, which can also limit the use of "*base units*" such as nuclear power.

As shown above an "*integration cost study*" to estimate the "*profile cost*" can be made with different set-ups. We will here make some of them.

4.6.1 Case 6-I: Assuming capacity replacement with original capacity factors.

Here we will start with 16000 MW of wind power, i.e. the same as case 2e. Starting from this level we will then introduce 1500 MW offshore wind power, 3500 MW on shore wind power and 3000 MW storage but in different orders. We assume the same wind for off-shore and on-shore wind power. We will here, in Case 6-I, assume set-up B, C and E. This means that we assume that both nuclear and wind power has the original capacity factors as in Case 1, and also the same LCOE as in Case 1. 8000 MW of wind power has, in Case 1, an energy production of 573750 MWh for 200 hours, i.e. each MW has a utilization time of 573750/8000 = 71.72 hours. Each MW of nuclear power has in Case 1 a utilization time of 200 hours. This means that, e.g., 1500 MW of wind power will replace 1500*71.72/200 = 538 MW of nuclear power for the same energy production in Case 1.

This means that when 1500 MW of off-shore wind power is added, then the nuclear power is reduced with 538 MW for the same energy production as in Case 1. When 3500 MW of extra on-shore wind power is added, then the nuclear power is reduced with 1255 MW.

The "*profile cost*" is then calculated, for each addition, as the change in total cost minus the LCOE assuming the fundamental capacity factor. Storage will case an "*profile value*", while wind in each case will replace the same nuclear energy (as in Case 1). The results are shown in Table 19.

Table 19 Integration cost calculation example with use of basic LCOE assumptions and different order of integration components.

				storage - on shore - offshore			offshore - onshore - storage			onshore - storage - offshore		
	Wind cap, nuc cap, basic LCOE	Base Case	Base Case-2	Add storage	Add onshore	Add offshore	Add offshore	Add onshore	Add storage	Add onshore	Add offshore	Add storage
	Case	1	6a	6b	6c	6d	6e	6f	6g=6d	6h	6i=6f	6j
1	Wind power [MW]	8000	16000	16000	19500	21000	17500	21000	21000	19500	21000	21000
2	Wind power [MWh]	573750	1147499	1147499	1398515	1505887	1254410	1500395	1505887	1396082	1500395	1505887
3	Utilization time [h]	72	72	72	72	72	72	71	72	72	71	72
4	Nuclear power [MW]	3000	3000	3000	1745	1207	2462	1207	1207	1745	1207	1207
5	Nuclear power [MWh]	600000	595057	600000	348137	240193	485486	228729	240193	339545	228729	240193
6	Utilization time [h]	200	198	200	200	199	197	190	199	195	190	199
7	Storage [MW]	-	-	3000	3000	3000	-	-	3000	-	-	3000
8	Storage [MWh]	-	-	183562	196870	201967	-	-	201967	-	-	201967
9	Total cost [kEUR]	241056	217015	216558	210063	207296	214449	208834	207296	211105	208834	207296
10	Wind power LCOE [EUR/MWh]	37,08	37,08	37,08	37,08	37,09	37,10	37,22	37,09	37,15	37,22	37,09
11	Nuclear power LCOE [EUR/MWh]	63,28	63,68	63,28	63,40	63,52	63,96	65,93	63,52	64,61	65,93	63,52
12	Total energy: Wind + Nuclear [MWh]		1742556	1747499	1746652	1746080	1739897	1729123	1746080	1735627	1729123	1746080
13	Change of total cost [kEUR]			-457	-6495	-2767	-2567	-5615	-1538	-5911	-2271	-1538
14	Change of nuclear LCOE cost [kEUR]			0	-15882	-6809	-6809	-15882	0	-15882	-6809	0
15	Change of wind LCOE cost [kEUR]			0	9308	3989	3989	9308	0	9308	3989	0
16	Change in total LCOE [kEUR]			0	-6574	-2819	-2819	-6574	0	-6574	-2819	0
17	"Profile cost" [EUR/MWh]			-2,49	0,32	0,48	2,35	3,82	-7,61	2,64	5,10	-7,61

If we take one example in order to show how to calculate the "profile cost". We here select case **6f,** which means that first we installed 1500 MW off-shore wind power, and here we study the impact of integrating also 3500 MW (row 1) of on-shore wind power. First, with the here used assumptions, 3500 MW of wind power replaces (see Base Case 1: different utilization times) 3500*(72/200)= 1255 MW of nuclear power in row 4 (assumed same energy production in Base Case 1). This means that change from Case 6e to Case 6f is +3500 MW wind power and -1255 MW nuclear power. The total cost (row 9) is now changed with 208834-214449 =-5615 kEUR, i.e. the total cost decreased.

Concerning changed LCOE cost, it is here assumed that we use the utilization time from Base Case 1 (row 11). The nuclear is decreased [1255 MW]*[200 h]*[63.28 EUR/MWh] = 15882 kEUR. The wind power cost increases with [3500 MW]*[72 h]*[37.08 EUR/MWh] = 9308 kEUR. This means that the total LCOE cost decreases with 15882-9308 = 6574 kSEK (rows 14-16). Here it is seen that the change in total cost is not as high as the decrease in LCOE. The difference with the definition of "*profile cost*" is that this difference is "caused" by the change in the system, in this case replacing nuclear with wind power. The "*profile cost*" idea is then to allocate this cost to wind power with leads to that the integration cost, per MWh, is [6574-5615 kEUR]/([3500 MW]*[72h]) = 3.82 EUR/MWh (row 17). From Table 19 **Fel! Hittar inte referenskälla.**it is shown, e.g.:

a) Storage is always a benefit for the system since the "*profile cost*" is negative.

b) All wind power integration is profitable for the system since total cost always decreases when wind power increases and replaces nuclear power.

c) The total amount of energy from wind + nuclear changes. This depends on that not all of these sources can be used. Storage increases the amount while more wind power reduces the amount of MWh per MW which can also be seen in the LCOE for the different cases.

d) The "*profile cost*" depends on the order of integration. If, e.g., storage is available, then 3500 MW of wind power has an "*profile cost*" (case **6c**) of 0.32 EUR/MWh. But if there is already 1500 MW of off-shore wind power, then the "*profile cost*" is 3.82 EUR/MWh, i.e., 12 times higher.

e) The conclusion is that if we want to study a "future system" with both on-shore wind, off-shore wind and storage it is **NOT** possible to define an "*integration cost per technology*", since the order of integration impacts the level.

4.6.2 Case 6-II: Assuming energy replacement with original capacity factors.

In section 4.6.1 we assumed that wind power capacity replaced a corresponding amount of nuclear capacity, where the set-up was that the energy production, in this replacement procedure was based on fundamental utilization times: 72 hours for wind and 200 hours for nuclear. However, the real energy production depends on the whole system where wind power has the lowest operation cost and when wind + nuclear available capacity is larger than demand, then the whole capacity cannot be used. Technically the approach in Case 6-I in section 4.6.1 implies that the "*lost energy*" in wind and nuclear has to be compensated in the rest of the system and will thereby be a part of the "*profile cost*".

The approach used here in Case 6-II is instead that the amount of wind power that replaces nuclear should also compensate for the "*lost energy*". This formally means that this "*lost energy*" is instead included in an "*increased amount of wind power*" instead of a "*profile cost*". The results from these calculations are shown in Table 20.

The table shows that there are clear changes in the results compared to results in Table 19. We can compare case 6e in Table 19 with case 6k in Table 20. These considers exactly the same change in nuclear power (- 538 MW) and this is replaced with wind power. In 6e it was assumed that it was replaced with as much wind power (1500 MW) so it gives the same amount of energy as 528 MW assuming the basic utilization times: 200h for nuclear and 72h for wind power. However, as seen in Table 19 the total energy production from wind + nuclear is not the same after this replacement. The change is (row 12) 1742556 – 1739897 = 2659 MWh for the studied 200 hours. Formally this means that the remaining fossil system has to produce these 2659 MWh of "*lost energy*" and this is then included as a "*profile cost*".

Table 20 Profile cost calculation examples with use of basic LCOE assumptions and energy replacement assumption

				offshore - onshore - storage		
	Wind capacity, nuclear capacity, basic LCOE	**Base Case**	**Base Case-2**	**Add offshore**	**Add onshore**	**Add storage**
	Case	**1**	**6a**	**6k**	**6l**	**6m**
1	Wind power [MW]	8000	16000	17540	21230	21230
2	Wind power [MWh]	573750	114749 9	1257225	151603 0	152223 4
3	Utilization time [h]	72	72	72	71	72
4	Nuclear power [MW]	3000	3000	2462	1207	1207
5	Nuclear power [MWh]	600000	595057	485331	226526	240193
6	Utilization time [h]	200	198	197	188	199
7	Storage [MW]	-	-	-	-	3000
8	Storage [MWh]	-	-	-	-	202723
9	Total cost [kEUR]	241056	217015	214341	208348	206619
10	Wind power LCOE [EUR/MWh]	37,08	37,08	37,10	37,24	37,09
11	Nuclear power LCOE [EUR/MWh]	63,28	63,68	63,98	66,43	63,52
12	Total energy: Wind + Nuclear [MWh]		174255 6	1742556	174255 6	176242 7
13	Change of total cost [kEUR]			-2674	-5993	-1729
14	Change of nuclear LCOE cost [kEUR]			-6809	-15882	0
15	Change of wind LCOE cost [kEUR]			4095	9815	0
16	Change in total LCOE [kEUR]			-2714	-6067	0
17	Profile cost [EUR/MWh]			0,36	0,28	-8,53

In case 6k in Table 20 the set-up is instead to compensate the "*lost energy*" in case 6e with more wind power. This means that here the decreased 538 MW of nuclear power is instead replaced with 1540 MW of wind power, which results in that the total wind+nuclear energy production (row 12) remains the same. The calculation of the "*Profile cost*" is done in the same way as previously, but it now becomes 0.36 EUR/MWh (case 6k) instead of 2.35 EUR/MWh (case 6e). The reason for the significant decrease (with 85%) of the "profile cost" depends on that now wind power produces more energy compared to case 6e. Some comments are:

f) The detailed method of how to estimate the "*profile cost*" has a large impact of the resulting level.

It can finally be commented that there are more assumptions that can be changed, as e.g. which LCOE:s to be used for nuclear and wind.

5 Actual market handling of wind power in Sweden

As an example of how to internalize other costs than the investment costs we will here take the example from Sweden. The costs in Table 21 and revenues in Table 22 relate to what a wind power farm owner in Sweden see.

Table 21 Costs for a wind farm owner within the Swedish regulation

1) Wind power plant costs	This is formally the LCOE, i.e. the cost for the wind power plant purchase
2) Internal grid cost	The internal grid in a wind farm is an addition to the cost of the wind power plants. In Sweden it is common to also include this in “wind power LCOE”, e.g. reported in lists of investment costs (Swedish Wind Energy Association, 2020).
3) Connection cost	In Sweden, the wind power owner also has to pay for the connection to the grid, i.e. for lines to the connection point and the transformer. The wind power investor also pays for needed investments in the upstream grid (formally deep connection charge). This is also normally included in “wind power LCOE”, e.g. reported in lists of investment costs (Swedish Wind Energy Association, 2020).
4) Yearly grid fee	In Sweden, both producers and consumers pay for the grid. The grid fee is different for different locations and grid owners. The fee normally has a per MW part, a per MWh part and a constant part. Since the MW part is rather high, then a wind power owner normally pays more, per MWh, compared to nuclear or hydropower since the utilization time is lower. The connection fee to the transmission grid, 220-240 kV, is available from (Svenska Kraftnät, 2021).
5) Imbalance cost	The power is, in reality, sold mainly day-ahead. Since the forecasts are not perfect, then there is often an imbalance cost which is paid by the wind power owner.
6) System service cost	The TSO has costs for system services, such as primary control etc. These costs are transferred to producers and consumers in relation to how much energy they produce/consume. All producers have the same fee, independent of they cause large needs of disturbance reserves (large units) or minor changes within the hour (weather dependent production). Details on (Svenska Kraftnät, 2021).

In Sweden there is also a “strategic reserve”. This is in reality a capacity payment for some units (after selection in an auction) that is paid by the TSO. The motivation is that extra capacity is used in rare situation, e.g. when it is extremely cold. The cost for this is paid by the consumers/retailers (since high consumption causes the need) in relation to the consumption (not grid losses): 0,27 EUR/MWh, weekdays 06-22 from November 16 – March 15. (Svenska Kraftnät, 2021).

Table 22 Revenues for a wind farm owner within the Swedish regulation

7) Income from selling power	The dominating income is from selling wind power day-ahead. The price for this is set by a price cross on Nordpool or if they select on other exchanges. Even if the power is sold without going through an exchange, then the dominating price is still the day-ahead exchange price (MWh/h), i.e. changing between different hours. It is possible to also have financial derivatives connected to this trade which limits the risk of uncertain future prices. Since the power is sold to the market at market price, then the "value factor", c.f. section 2.5, is included in the revenue.
8) Income from certificates and GOO:s	In Sweden there has historically been a certificate market for certified power plants (e.g. wind power). But there has been so much wind power installed so this price has more or less collapsed. The last day for new entrance to the certificate system is December 31, 2021. A wind power owner can also sell Guarantees of Origin, but this price is currently also very low.
9) Provision of system services	Formally also a wind power owner can participate and sell system services, e.g. frequency control, but currently (2021) this is not common. However it may increase in the future and it is shown that it may be profitable (Wiklund, 2021)

In Sweden it is currently (2021) rather common that wind power is sold with a PPA, power purchase agreement (ELS Analysis, 2020). This can be designed in different ways, but can mainly be seen as a financial agreement, which reduces the price risk for both producers (wind power owner) and consumer (the one who needs the production). However, there are still all the costs in Table 21 that have to be paid. There may also be a "green value" in the wind power, corresponding to a specific GOO for this specific deal.

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SYSTEM AND INTEGRATION COSTS IN WIND AND SOLAR ENERGY

Här diskuteras integrationskostnaden för vindkraft, det vill säga storleken på de övriga kostnader som tillkommer i ett kraftsystem när mängden kraft från vind och sol ökar. Målet är en samhällsekonomisk och hållbar elförsörjning där samtliga konsekvenser av olika försörjningsalternativ beaktas, inte enbart vad en viss anläggning kostar.

Rapporten beskriver utmaningarna med att uppskatta de totala kostnaderna för att dimensionera ett elsystem. I den första delen av rapporten uppskattas systemkostnaden, det vill säga de totala kostnaderna för ett specifikt elsystem. Det behövs elproduktion och elnät, men även rimliga marginaler och utrustning som gör att man kan hålla en ständig systembalans mellan produktion och konsumtion.

I den andra delen uppskattas en integrationskostnad för exempelvis elvärme, elbilar, vindkraft eller solkraft där man förutom själva anläggningen behöver mer utrustning för att hela elsystemet ska fungera. Det är en utmaning att definiera den kostnaden och hur den ska allokeras till en specifik teknologi.

Rapporten innehåller också numeriska exempel där syftet är att inte bara visa kvalitativa utan också kvantitativa resultat för kostnader vid olika antaganden om systemuppbyggnad. Resultaten visar att värdefaktorn och integrationskostnaden kan variera med mer än en faktor tio, vilket är mycket mer än antaganden om kostnaden för produktionsanläggningarna.

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