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Cost of flexibility in the future European power system

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PROBLEM DESCRIPTION

European climate and energy goals towards 2030 and 2050 imply massive integration of wind power and solar power, which are intermittent and difficult to forecast. It is therefore necessary to exploit several means to provide sufficient flexibility in the upcoming European power system. The opportunity of expanding the Norwegian hydropower system with new pumping facilities in order to contribute with significant balancing and peak load power have received increased attention.

Therefore, the objective of this report is to analyse the cost of providing flexibility in the future European power system. The study will cover the following topics

1. Provide an overview of methods for calculating levelized cost of electricity (LCOE).
2. Establish a spreadsheet model for calculating LCOE of different flexible power generation technologies.
3. Present case study analysis with selected scenarios for external parameters like fuel prices, carbon taxes and plant parameters. Also, including cost of cable and necessary grid upgrades, predict how it will look like for Norway to invest in a “green battery” illusion. Especially, the Norwegian pumped storage hydropower’s economic feasibility is one of the main topics.

PREFACE

When I started my higher education, I was passionate about the combination of environment and technology, aiming for an education where I could learn more about my genuine interests. After five years I end my student career focusing on how the future energy system in an economical, efficient and secure manner can meet the required share of renewable electricity generation that are necessary for a worldwide environmental sustainability. I find myself lucky to have gotten this opportunity.

This report is a master thesis written for the department of Electrical Engineering at NTNU. The study was written during the spring semester of 2015. The aim was to analyse the cost of providing flexibility in the future European power systems. The focus has been towards pumped storage hydropower and Norway's ability to act like an energy storage facility to the European continent.

I would like to thank my supervisor Magnus Korpås for giving me valuable advice and all the support needed during this work. Thank you for all the interesting discussions and for your enthusiasm.

ABSTRACT

Commitments from the European energy and climate of 20 per cent renewable energy share in the energy generation system by 2020 and a 85 to 90 per cent reduction in greenhouse gas emissions in 2050 entails a higher penetration of non dispatchable renewables like solar and wind in the future European energy system.

For the electricity system to guarantee equilibrium between generation and consumption, flexible generation units are necessary to cover unpredictable periods with small amount of wind and cloudy hours. The best alternatives for flexible generation comes from hydropower, pumped storage hydropower (PSHP) and gas fired power plants. Coal fired and nuclear technology seems not to deliver the flexibility necessary, and are also less cost efficient when a lower load factor situation might be the future for conventional technologies.

This report presents a levelized cost of electricity (LCOE) study. LCOE is a convenient measure that summarize the overall competiveness of several different generating technologies. For this analysis, a spreadsheet model has been made, both for the purpose of this thesis and for general use. The report and the model provides simple clear metrics based on up-to-date information and future scenarios from reliable sources. All the collected data are used to evaluate both costs and performances of different conventional technologies, and their ability to act as a flexible resource in the energy mix for upcoming years. To account for the development of fuel price and carbon taxes, International Energy Agency (IEA) has predicted scenarios that are included in the model. The report is a supplement to the large debate of renewable power generation and the need of more available flexible generation. This study will hopefully assist key decision makers to make the right choice in policy and investment.

In general, Norwegian hydropower and PSHP turns out to offer the lowest LCOE in most scenarios. For a closer comparison between some of the most flexible generation sources, a case study with a load factor of typically 0.3 and central values for pumping price, capacities and investment cost shows a LCOE of 51.1 for hydropower, 77.2 €/MWh for PSHP, 118.8 €/MWh for CCGT and 153.6 €/MWh for CCGT w. CCS. The results seems to be promising for PSHP development. However, PSHP and hydropower proves to be sensitive to parameter values and discount rate. Hence, it will be of a higher risk to invest in PSHP than for example gas fired technology.

The Norwegian hydro generating facilities needs transmission connection to reach the continent, while gas and coal fired power plants may, in theory, be placed wherever in Europe without any extra large transmission or grid related costs. When adding Statnett's share of the Nord.Link project, and the estimated cost of grid upgrades necessary to Norwegian hydropower and PSHP, the LCOE becomes 64.4 €/MWh for hydropower and 99.1 €/MWh for PSHP. Simply, the rich hydro resources from Scandinavia is definitely of the better economical options, even with the high additional share of costs related to transmission and grid upgrades.

This study shows that the investment of transmission connection between Norway and the European continent will give several benefits. The PSHP seems to offer the required ancillary services needed when a larger share of intermittent renewables will take part of the future European energy system. Several sources claims Norwegian PSHP will have a decisive role in the future, offering valuable flexibility to the European power system.

SAMANDRAG

Med klimamål frå EU om ein betydeleg reduksjon av klimagassutslepp samt 20 prosent fornybar kraftproduksjon innan 2020, gjer at det Europeiske kraftsystemet treng ein større andel fleksibel kraft dei neste åra. Dette for å dekke delvis uforutsigbar kraftproduksjon fra vind og sol, samt møte måla som er satt fram mot 2020 og 2050.

Det viser seg, gjennom denne studien, at norsk vannkraft og pumpekraft i tillegg til gasskraft gir den beste fleksible kraftproduksjonen. Kullkraft og kjernekraft gir per i dag ikke nødvendig fleksibel produksjon, og er mindre kostnadseffektive ved lavare lastfaktor, noko som kan bli den framtidige driftsituasjonen for konvensjonelle kraftverk.

Denne rapporten presenterer ein LCOE (levelized cost of electricity) - studie. LCOE summerar kostnadane over eit kraftverk si levetid og fordeler den på mengde elektrisitet generert. På denne måten kan ein måle den økonomiske konkurransedyktigheita blant ulike teknologiar. Som ein del av arbeidet har det blitt laga ein rekneark-modell, både for denne studien men også for generell bruk. Denne modellen baserer seg på den nyaste informasjon frå energibransjen relatert til kostnader og parameterar for å berekne LCOE. Teknologiane som har vorte vurderte er fleksible kraftproduserande teknologiar som blir avgjerande å ha tilgong på i komande år. Det er tatt stilling til International Energy Agency (IEA) sine scenarioer for utviklinga av gass- og kolprisar, karbonutgifter, med meir.

Norsk vasskraft og pumpekraft gjev, i dei fleste analysane i denne studien, den lågaste LCOE. Dersom man vurderer ein tilsynelatande typisk «case» med lastfaktor på 0,3, og middels verdiar for investering, kapasitet og kraftpris for pumping, vert LCOE 51,1 €/MWh for vasskraft, 77,2 €/MWh for pumpekraft, 118,8 €/MWh for CCGT og 153,6 €/MWh for CCGT med CCS. Resultata for norsk pumpekraft viser seg generelt å vere lovande, men det viser seg at LCOE er sensitiv til parametarar som investering, rente og pris for pumpekraft. Det vil med andre ord vere større risiko å investere i pumpekraft enn for eksempel gasskraft, som er meir avhengig av utviklinga av framtidige gass og kolprisar. Teknologiane som baserer seg på gasskraft viser mindre sensitive LCOE.

For at Norge skal bidra som ein grønt batteri for Europa sitt energisystem i framtida trengs det internasjonale forbindelsar for kraftutveksling. Dersom ein adderer Statnett sine estimerte kostnader for den nye kabelen til Tyskland, som inngår i Nord.Link prosjektet, i tillegg til nødvendige kostnader for oppgradering av eksisterande nett, til norsk vasskraft og pumpekraft, vert LCOE 64,4 €/MWh for vasskraft og 99.1 €/MWh for pumpekraft. Med andre ord, dei norske forholda ser ut til å tilby økonomisk gunstige alternativ for det Europeiske kraftsystemet, sjølv om med ekstra kostnader relatert til kraftutveksling.

Studien viser at investering av kablar for kraftutveksling mellom Norge og kontinentet vil gi mange fordelar. Pumpekraft kan brukast for å lagre overskudd av energi frå fornybar produksjon, samtidig som systemet kan tilby frekvenskontroll, opp- og nedregulering, og har gode eigenskapar for rask kraftgenerering ved utfall i systemet. Fleire kjelder påpeiker at norsk pumpekraft vil ha ein avgjerande rolle i det komande Europeiske kraftsystemet. Norge kan absolutt, både frå eit økonomisk perspektiv og for tekniske behov, bli Europa sitt grøne batteri.

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LIST OF ABBREVIATIONS

ASC	Advanced Supercritical
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CO2	Carbon Dioxide
DECC	Department of Energy and Climate Change
EPC	Engineer, Procurement and Construct
FOAK	First of a kind
HHV	Higher Heating Value
IGCC	Integrated Gasification Combined Cycle
LHV	Lower Heating Value
OCGT	Open Cycle Gas Turbine
O&M	Operation & Maintenance
PSHP	Pumped Storage Hydropower
RES	Renewable Energy Source
TSO	Transmission System Operator
UoS	Use Of System
WEO 2014	World Energy Outlook 2014

1 INTRODUCTION

The electricity landscape in Europe is undergoing profound changes. The aim is an energy sector with lower carbon facilities and an increased share of various renewable energy sources (RES) in the energy generation mix. Unfortunately, the higher share of RES leads to mismatches between unpredictable renewable generation and consumption. The European energy system needs to cover the mismatches.

While history, tradition, shows that gas power peaking plants have been used to cover variation between consumption and supply, there might be an expensive future coming up with raising fossil fuel prices and carbon taxes. Actually, International Energy Agency have announced outpacing of 150 000 MW thermal power production (gas, coal, nuclear) in Europe before 2035 due to end of operational lifetime. The same agency have released World Energy Outlook 2014, which gives three scenarios of how the different costs may evolve. Considering these trends, how will the levelized costs for fossil fuel burning power plants like gas and coal develop? Should the European power sector invest in new thermal power production? What kind of alternatives do we have to cover the mentioned mismatches?

With cross border transmission connections towards Germany and the UK, it is interesting how Norway can interfere with the continent. The favorable conditions for large-scale hydropower and pumped storage hydropower (PSHP) in Scandinavia have for a longer time period been evaluated having the potential to serve as a “green battery” for the European continent. It seems like we are closing up on this illusion with Statnett’s new investment of sea cables towards Germany and the UK, namely the Nord.Link project and the North Sea Network project. However, it is not obvious that Norwegian hydropower and PSHP are the best alternatives to cover the flexible generation necessary. What options do we have for the future energy system, and what is the best economical alternative? How to establish a positive trend towards a better climate and how to secure energy supply together with the higher share of non dispatchable power generation?

One way to measure the economics cross technologies is to compare the levelized cost of electricity (LCOE) of various generating alternatives. LCOE represents the per kilowatt hour cost of building and operating a power generating plant over its lifetime and duty cycle. LCOE is expressed in net present value terms, which means that all predicted future costs and generation are discounted to a specific date. In this way, different generating technologies can be compared in an economical matter despite the individual differences between technologies. Still, there are several ways to calculate LCOE. What costs to include, various discount rates and the level of detail can make results differ. How can the various LCOE calculation methods affect the result?

In this way, the objective of this report is to analyse the cost of providing flexibility in the future European power system. This study will cover the following topics

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Background

This report has been written as a master thesis for the Department of Electric Power Engineering at NTNU during spring semester of 2015. The aim of the study is to analyze the cost of providing flexibility in a future European power system dominated by a larger share of intermittent renewable energy generation. Different flexibility options will be evaluated. Norwegian PSHP facilities will gain some attention due to the newly risen opportunity to interfere to a larger extent to the European power system. Statnett's ongoing project of cable connection to Germany, namely the Nord.Link project, is therefore to be included in some of the LCOE case studies.

The work will be linked to the ongoing research project CEDREN-Hydrobalance, where Department of Electric Power Engineering has an active role, together with project coordinator SINTEF Energy Research.

Report structure

First, the reader will be introduced to the different power generation technologies that are considered in this study. Further, the methodology for the LCOE calculation is explained and different methods for calculation from various sources are presented. Afterwards, the reader will get familiar with the spread sheet model. For example, how the model is designed, what costs and data that are included and how and where the individual costs has been collected. Finally, the results from case studies are given and discussed.

General limitations

This study provides insight to the levelized cost of generated electricity. Since the main focus is technologies that can offer flexibility, the levelized cost calculations has been directed towards these alternatives, excluding the intermittent renewables like solar photovoltaic, wind power etc. Additionally, even though nuclear power and coal fired power generation may not operate in a flexible manner today, the technologies are also considered and compared in this study to serve a total picture of what the various conventional technologies can offer. Analogously, this study includes the technologies of hydropower, PSHP, gas power, coal power and nuclear power. Power production from biomass has been excluded from this study.

When it comes to hydropower and PSHP, the cost data and information used are specifically for Norwegian conditions, since the work is related to how Norwegian hydro can contribute to sustainable power generation to facilitate wind and solar integration in continental Europe. Other proven large scale storages, like batteries and compressed air technology, are not considered in this thesis.

The parameters chosen in the model are limited to what the writer finds worth to include. All costs have been calculated with an inflation rate of 2.3 per cent, and are given in the report in 2014€. It is being addressed otherwise.

2 FLEXIBLE GENERATION

Commitments from the European energy and climate of 20 per cent renewable energy share in the energy generation system by 2020 and a 85 to 90 per cent reduction in greenhouse gas emissions in 2050 entails a higher penetration of non dispatchable renewables. One already implemented action in the European energy system is the integration of on and offshore wind power production and a larger share of electricity production from concentrated solar power or solar photovoltaics. In the future, the amount of generated electricity from especially wind and solar resources will raise.

When it comes to electricity, this is the ultimate momentary product! The consumption is in the exact moment as it is produced. With raising amount of intermittent energy supply from wind and solar in the European energy system, the energy will fluctuate considerably. It is a tough task to predict the precise output of wind and solar generation. Meteorological conditions and unforeseen different events are the reasons for this. Even though advanced technologies and utilities can help, there is still a substantial share of uncertainty surroundings these kinds of "foreseen" weather patterns. An additional factor is all the maintenance, misoperations and faults when it comes to production plants and transmission lines and cables. The consumption varies and can be most volatile.

There is need for regulations to achieve and obtain an energy balance. To some extent, one can predict some of the regulations necessary by wind, solar or hydro prognoses. Errors and misoperations can, in most cases, not be foreseen. To be able to operate the European power system in an efficient and secure manner in the future, it is necessary to exploit several means to provide sufficient flexibility in the system.

Flexibility

Flexibility is the ability of a system, such as a manufacturing process, to cost efficiently vary its output within a certain range and given time frame. In the energy sector, the term flexibility is often associated with quickly dispatchable generators. A wider definition also includes system operation, like transport, storing, trade and consumption of electricity [1]. Flexibility expresses in this report the full capability of a power system to provide reliable supply when the system is facing large and rapid imbalances.

How Europe shall meet the flexible power requirements the world region is facing is under discussion and evaluation. When it comes to the need of flexibility, the truth is that for a system to work in a sustainable manner, resources available for future use are both beneficial and necessary. Further, flexible power generation can be of several kinds. Today, the European power system use gas fired technology, often peak power from OCGT, and hydropower, to be able to meet the flexible need of power. For managing the variability of non dispatchable renewables and secure flexibility and stability of grid operation, The Union of the Electricity Industry, Eurelectric, suggests the following being necessary [2]

1. Dispatchable flexible and back-up generation
2. Demand-side participation and storage
3. Interconnections
4. Market tools (e.g. market coupling or capacity remuneration mechanisms)

For information, it is assumed in this study that necessary market tools (point 4) are available and in use when it comes to future power system managing. Demand-side participation and storage (2) are not considered in this thesis, but are obviously an interesting topic for future use of network services.

Furthermore, irrespective of technology, all generators share the following characteristics given in Table 1, which influence the power plants flexibility and cost of operation. In addition, the various plants has their individual ramp time and minimum run time. See Table 2.

Table 1. Characteristics for flexible generators.

Characteristics	Definition
Ramp rate	How quickly the plant is able to raise or lower its power output. Often given in MW/h or percentage of capacity per unit time.
Ramp time	How long time it takes between the generator is turned on until it can provide electric energy to the grid. Often given in h.
Lower operating limit	The minimum amount of power a plant can generate once it is turned on. Given in MW.
Minimum run time	The shortest time period the plant must be run once it is turned on. Given in h.
Start up and shut down cost	Cost of turning the plant on and off. Given in €/MWh.
No load cost	The cost of keeping the plant “spinning” to be able to produce a necessary amount of energy when it is demanded. Given in €/MWh.

Table 2. Ramp time and minimum run time for various technologies [3].

Technology	Ramp time	Minimum run time
Simple - cycle combustion turbine	Minutes to hours	Minutes
Combined - cycle combustion turbine	Hours	Hours to days
Hydropower and PSHP	Minutes	None
Nuclear power	Days	Weeks to months

2.1 DISPATCHABLE ALTERNATIVES

The dispatchable alternatives refers only to technologies studied in this thesis. As mentioned, biomass power production has been excluded, and also proven large scale storages, like batteries and compressed air technology, has not been considered.

Conventional technology on the continent

When intermittent renewable energy becomes a larger share of the energy mix, there will become a larger share of unpredicted generation from conventional technologies. For flexible operation, the problem is the change (i.e., ramp) between full and partial load for power plants. It involves load changes of three percentage points, approximately, per minute [4]. The change in mode of operation must be achieved by a generating alternative that fulfills the requirement.

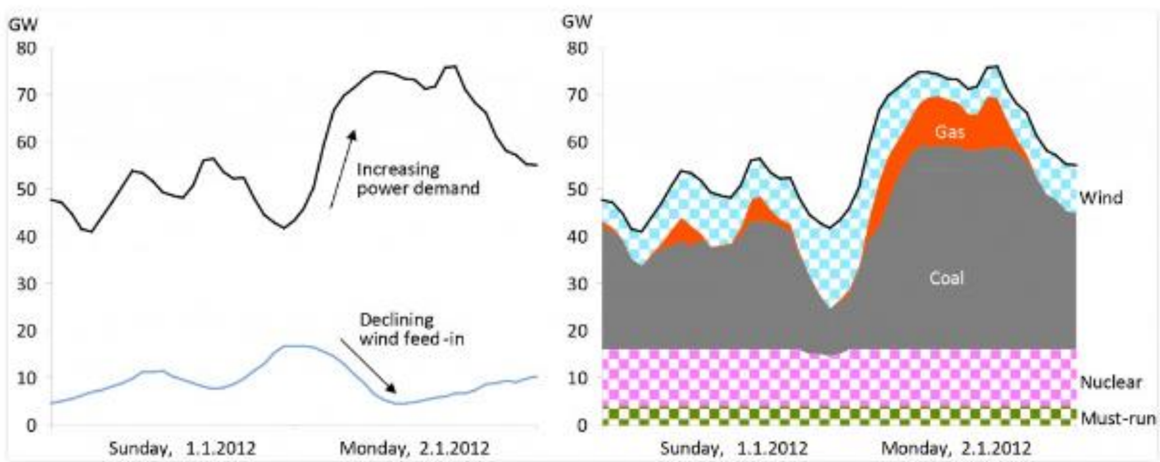

Figure 1. Power consumption to the left and dispatch of German power plants to the right [4].

Figure 1 is showing how the power generation from renewables can differ from power demand. It is clear that the energy system need flexible sources, like power from gas fired technologies in this case, covering the large and sudden gap between generation and demand.

The situation of conventional power plants operating in Europe has been the same since the year of building in the 1980's and 1990's. The plants were planned and build before expansion targets for wind and solar power had been adopted. In some of the plants, entities to allow larger share of flexibility have been implemented subsequently. In this way, the power plants can be more able to meet the increased requirements for load adjustments in the market. Still, there are quite large technological and economically challenges that needs to be faced.

If these conventional generating systems shall operate optimal in the future system, the power stations needs to work more frequently and speedily to balance the non programmable renewables. The technology needs to be developed to handle more frequent situations with hurry starts up and ramp rates. Without making the necessary adaptions it will make an increased risk of the amount of maintenance and the down time that can occur. It is not an easy task to adapt a power plant.

Gas fired technology

To cover peak periods, gas fired technology have been the most used technology of all power generating alternatives. Generation from OCGT was introduced decades ago for necessary peak load services. OCGT has got hurry ramp rates and quick start ups that makes it a suitable choice, and is used for these kind of services today. Combined cycle technology, as CCGT, is able to follow load demand and provide back up power when needed. Also, relatively low investment cost is a good argument to invest in this power generation method. However, operating cost is dependent on fuel consumption, leading to a less attractive cost picture.

Gas fired technology has an advantage compared to some of the other conventional technologies. It can offer black start up managing and relatively hurry start up in general. In addition, it can offer base load generation, and midmerit and peak load services.

In spite of this, it is no secret, fuel burning lead to greenhouse gas emissions. The gas technologies are not making a positive contribution to lower the amount of environmental damage. To respond to the decision of lowered carbon release to the environment, it will not be future oriented to alone invest in this technology. This despite the fact it definitely is the most used flexible option these days and carbon capture and storage (CCS) is a well known and used supplement. Nevertheless, Eurelectric claims that Transmission System Operators (TSOs) will face problems with the volatile running of gas power stations if it alone shall handle the sudden ramping up and down. The plants will generate shortfalls and surpluses of gas in the TSO's transmission system as a whole or in specific parts of the system. Market participants will need to have access to several flexible sources [2].

It is a fact that gas fired power plants are currently, in some areas in Europe, struggling to make a return on their investments and to stay in operation. CO_2-limitations, higher carbon related costs, a raise in gas prices, and more integrated renewables has made gas fired power plant usage has shrunk. Europe is experiencing several shutdowns and decommissioning because of this.

To get the full effect of CCGT, the system has to start at least one hour before power is needed. When CCGT is used as back up, the turbines are continuously spinning and therefore loosing in total efficiency. Additionally, conventional plants have to run for several hours to make the power generation profitable.

Normally, electricity is traded by hour on the spot marked. Nevertheless, the fluctuations in demand and price are faster than that, and they are accelerating. It is clear that the business of power production has changed extremely, and is becoming even harsher. For a CCGT that is not fast enough, working as a back up, the situation is getting more and more difficult. A tough challenge is that at any time, the decision must be made, as to when to shut down and start up various power plants. The operators have to consider the fact that the power plant is slow in starting. When starting up, it is preferable to run the plant for a while and sell electricity over a period. Hence, avoid producing electricity at a loss. Forecasting the daily load patterns will no longer be enough, meaning the CCGT needs to meet the intraday challenges better than today.

Coal fired technology

Usually, classical coal fired power plants are used for base load activities and often for back up management. Today, a base load coal fired power plant have little flexibility in generation. The plant type are not, only partly, suitable for flanking fluctuation output from renewable electricity generation. The equipment and the fuel in base load plants are most often unsuitable for peak power plant usage. The fluctuation conditions would strain the equipment.

Between demand times, it can be normal with power plant shut down. In the future, it may seem economic beneficial to run plant at low load if the plant shall act more flexible. In this way there will be a reduction in losses and start ups that may cause damage due to cycling and hurry demand. A reduction in the stable minimum load will improve the competitiveness of coal fired power technology as a flexible source in the future energy mix [5].

Other solutions may also be implemented to make the coal fired power plants more flexible. Today, stable minimum load is typically 30 per cent. With an optimization of the boiler turbine, by modern control systems, it is possible to reduce the minimum load of operation. Actually, today, optimized power plants do manage to operate at a partial load level beneath 20 per cent of max capacity [5].

When it comes to fossil fuel consumption, it is no secret coal burning leads to releases of carbon dioxide, nitrogen oxides, sulfur dioxide, and mercury compounds. The EU has claimed leadership on mitigate climate alteration. Still, CO_2 emissions from European coal power plants have recently risen. Coal prices are cheaper than gas prices, and many coal fired plants are therefore running with a high load factor. As mentioned, this leads to closing down of gas fired power plants. For many reasons, coal plants are required to reduce the amount of emission released by control devices. Nonetheless, coal fired power plants are responsible for a large percentage of the energy sector emissions. Actually, although only 40 per cent of the world energy production comes from coal fired power generation, the plants are still responsible for approximately 70 per cent of the emissions [6]!

Figure 2. Top 30 CO_2 polluting thermal power plants in Europe. Source: WWF [6].

From the perspective of Europe, it is interesting that the UK and Germany are self-declared climate champions of the EU. In spite of this, Germany is today one of the largest users of coal for electricity generation in the EU. The UK takes the third place in absolute coal consumption for power generation after Poland [6]. Actually, in Germany in 2012, around 52 per cent of the net power generation came from brown and hard coal fired power plants [7]. Coal is actually Germany's most abundant indigenous energy resource. After Japan's Fukushima reactor accident occurred in March 2011, coal consumption has increased since Germany have used coal as a substitute for nuclear power for electricity generation.

Nuclear power technology

Nuclear power has the possibility to play a major role the worldwide project of decarbonizing. Even though, it has the disadvantage that it cannot easily follow peaks and instant differences between supply and demand. Hence, it does not have the ability to meet power grid needs in an efficiently and safe way. All nuclear reactors might, in principle, be regarded as having some capacity to follow load demand, but it is restricted to a specific set of design types [8]. If it is going to help meet future requirements of flexibility in the energy sector, some technological upgrades needs to be done.

Of course, the relative competitiveness of nuclear among other generation options varies from one area to another. Despite of local differences, the nuclear power cost structure always contains more fixed costs, particularly capital costs than alternatives based on fossil fuel. This is the main reason why base load operation is in general preferred for nuclear power plants. One can safely, although perhaps somewhat simplistically, make the assumption that, given the cost structure of nuclear power, operators would want their nuclear power plants to operate full load hours as much as possible. This for income maximization.

In general, nuclear power has previously been competitive above 5000 hours of operation per year [8]. This has directly led to semi-base and base load operation of these kinds of plants. When real load following operations is the situation, with smoothly varying outputs, in real electricity markets, it would represent a much more complex matter. No data appears to be available for this sort of running a nuclear power plant.

After the accident in Fukushima, several governments have appeared to imply a phase out process of nuclear power generation. Especially Germany, where Mengler have pronounced all nuclear shall be out phased by the year of 2022. This is not the situation all over Europe. This makes it still an interesting generation technology to consider. Even though it may not the best flexible generation option, it will, most certainly, be needed to cover traditional base load generation.

As mentioned before, one major benefit from electricity generation from nuclear are the power plants do not emit carbon dioxide, sulfur dioxide or nitrogen oxides. Unfortunately, the uranium mining and enrichment process as well as the transport of the uranium fuel to the nuclear plant are associated with fossil fuel emissions. Still, during its operational lifetime, the emissions can not be compared in the same matter as contribution to greenhouse gasses from gas and coal fired technologies.

The final step regarding the life of a nuclear power plant is the decommissioning, which are a bit more comprehensive compared to other types of power plants. It is particularly important given the need to manage the radioactive materials in a safe way. It includes all activities from shutdown and removal of fissile materials to environmental restoration of the site. The cost of decommissioning depends on several factors like plant location, arrangements for nuclear waste storage and disposal and legal requirements.

Hydropower and PSHP

Hydropower is a mature technology. In the early decades of the 20th century a lot of hydropower plants were build and are currently still in operation. Even though, the majority of them have undergone rehabilitation, modernization or some sort of redevelopment.

Conventional hydropower is one of the greatest and largest forms using stored energy. A complement to the conventional hydropower production is pumped storage hydropower (PSHP). PSHP is currently one of the very few proven large scale (>100MW) energy storage technologies and it is a well known technology for utility-scale electricity storage [9]. For the reader that are not familiar with the technology, the fundamental principle is to pump water to a higher level reservoir using lower cost electricity from the grid when demand is low. In this way, hydraulic potential energy can be stored. By releasing water through a turbine, the transformation is made back to electricity when demand is raising (power peak periods) or when the price of electricity is high. Both pumping and generating manage to follow daily, weekly or seasonal cycles, depending on size of reservoir. The total size of energy storage capability depends on evaluation differences between reservoir and the total volume of the water stored for usage.

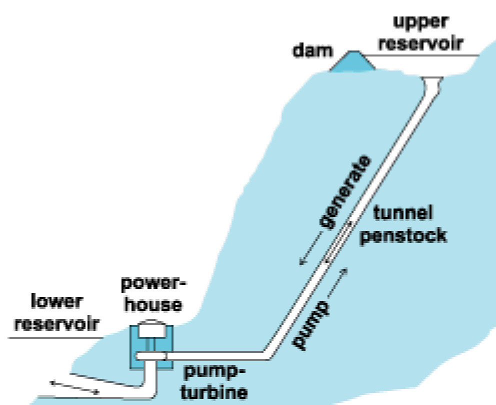

Figure 3. Pumped hydro storage principle. Source: Peak Hour Power, LLC [10].

Later years, the discussion about PSHP has evolved and renewed after some years with little attention. This is seen especially in Europe, Japan, Austria and the US. The integration of non flexible power plants and variable renewable energy makes an increase in the potential of PSHP.

In Europe, the majority of PSHP facilities are located in the Alpine regions of France, Switzerland and Austria. Germany however has the largest number of PSHP plants with 23 plants in operation, ranging from 62.5 MW to 1060 MW in installed capacity. At present, PSHP in Germany has a combined output of 7 GW, approximately [11].

Joint Research Center have made an assessment of the European potential of PSHP systems that declares a potential of 54.3 TWh for PSHP where existing topography for already existing magazines can be used (with the limit of 20 km between upper and lower reservoir). A larger potential is shown for the potential of artificial magazines [9].

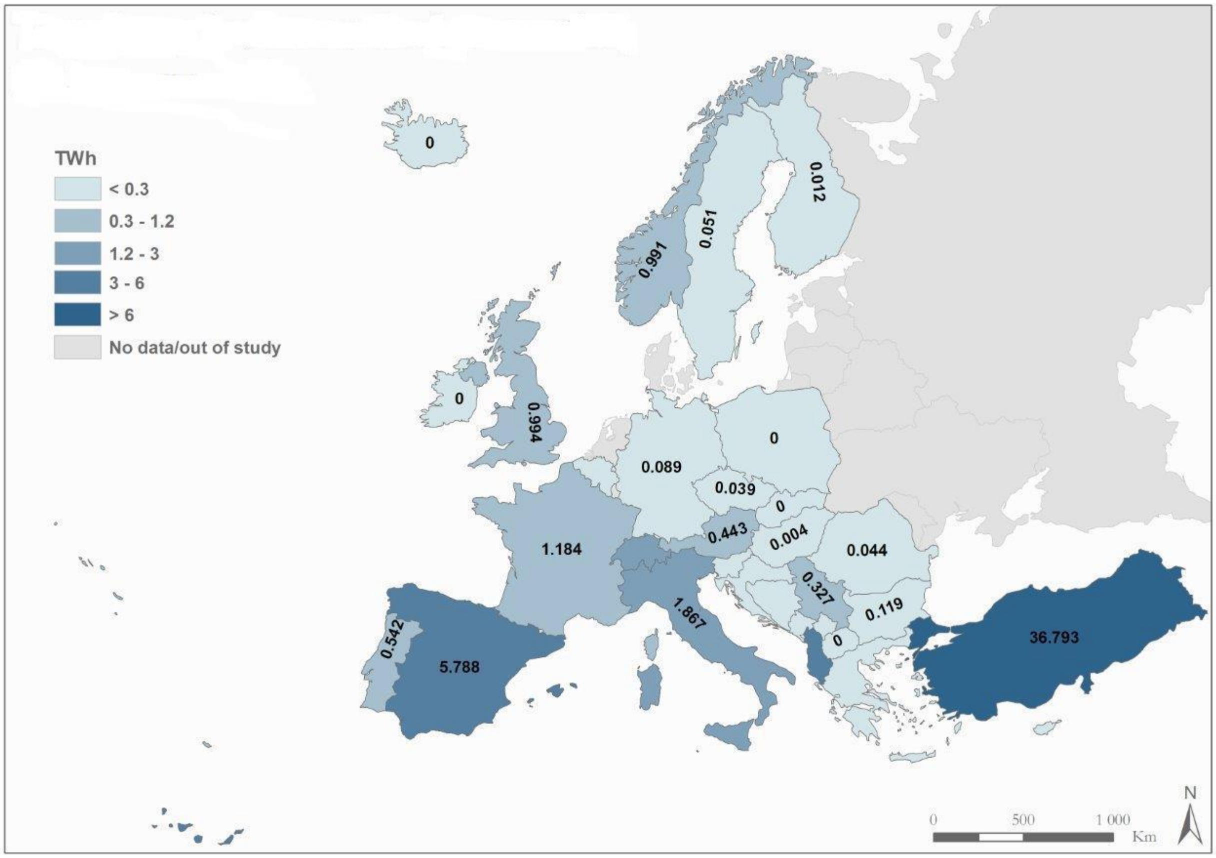

Figure 4. PSHP potential in Europe. Source: Joint Research Center, 2013 [9].

PSHP is subjected to uncertainties and fluctuating costs. The reason for this statement is the high capital cost influenced by the civil work, which depends on location and site conditions. The facilities can be very expensive to build and some refers to controversial environmental impacts and comprehensive permitting procedures. Even though high investment is a fact, the system has low operation and maintenance costs. PSHP usually comes with long asset life, often 40 to 80 years.

For information, in general, electricity trading is the largest income for revenues for PSHP system operators, since they take advantage of energy arbitrage opportunities. Pumping price needs to be approximately 25 to 30 per cent lower than selling price to achieve arbitrage [12]. This is to compensate for energy losses.

PSHP systems beneficial

The benefits of having PSHP in an operating electrical system are many. PSHP are capable of quick start ups to meet daily peak demands and emergency situations. The quick start capabilities makes them suitable for circumstances like black starts and provision when it comes to behave as a spinning and standing reserve. It can be ramped up more rapidly than any other generation unit. PSHP can also help with grid stability and it can therefore provide the full range of ancillary services required for the high penetration of variable renewable energy sources. This makes the PSHP definitely one of the major technologies that can offer future necessary requirements. In addition, as for the decarbonization agenda, hydro driven facilities has been identified as highly valuable for the mitigation of climate changes because of their low carbon footprint and high efficiency.

Development of PSHP in Norway

PSHP is a resource driven facility. This means the satisfactory site conditions are crucial to make a project viable. This includes favorable topography, water availability, high evaluation between reservoirs and a qualified geotechnical basic. There is also a momentum to have access to electricity transmission networks, since extreme grid connection costs can make projects economically unfavorable. Luckily, the Nordic area is blessed with high mountains plateaus and rich hydro resources. Norway is actually an optimal place to invest in cheap energy from the hydro sources available. In most parts of the country, high level of rainfall is also making a positive contribution.

In other countries, the situation can be very different. Lower mountains, meaning less head, and need of artificial magazines may often be the situation. Because of this, it appears that capital costs of conventional hydropower plants and PSHP systems elsewhere are considerably higher than capital costs of Norwegian and Swedish hydropower development.

Eurelectric has in a report from 2011 announced Norway’s important storage capacity and potential. The report mentions three major renewable batteries in Europe, namely Norway and the Scandinavian region, the alpine region, and to a lesser extent, the Pyrenees. Norway has almost 50 per cent of the reservoir (storage) capacity in Europe. Today, the flexibility of the storage hydropower from Norway enables the integration from RES within the Nordic market. Mostly, this yields electricity generation from wind power in Denmark [13].

Another assessment about Norwegian hydropower potential, from SINTEF Energy AS, commissioned by CEDREN, indicates it is possible to increase installed capacity in Norwegian hydropower facilities with 20 000 MW, excluding making new regulated magazines. The main scenario contains 12 new plants in southern part of Norway, with an installed capacity of 11 200 MW. 5 of these are PSHP (5200 MW), while 7 are regular hydropower plants for effect running (6 000 MW). The mentioned 12 new plants can raise its installed capacity to 18 200 MW, without the higher and lower magazine crosses its regulation boundaries of a water level changes of 14 cm/h, but this will of course be affected of the running strategy of the PSHP [14].

The same study from SINTEF Energy AS also concludes that the upcoming cross border intersections will alone not occupy transmission capacities in the Norwegian power grid. In spite of this, for operational reasons, it will be beneficial, both for cable connections and the high voltage transmission network, that the power stations have strong connections to the main grid. When transmission interconnections are out of service, the different power plants must be able to serve the grid themselves, which means new 420 kV lines and existing 420 kV lines need upgrades in several locations in Norway [14].

As mentioned, preliminary studies on Norway's possibility to increase pumped storage capacities demonstrates a high potential if the existing reservoirs were used differently. For this to happen, Eurelectric mentions the following challenges that needs to be met [13]:

- increased transmission capacity between Norway and the European continent
- increased social acceptance for new transmission lines
- incentivising business models for pumped storage hydropower plants

Until now, unfortunately, PSHP has not been economically profitable in Norway and Sweden. The large amount of conventional storage hydropower plants, who takes care of power system services needed, makes the need of PSHP not big enough [13]. However, with increased transmission capacities to Europe the situation will probably change.

Transmission connections cross country borders

Before Norwegian hydro facilities can offer its total flexible potential to the continent, significant investments in cables, grid and power stations upgrades will be absolutely necessary. Statnett have newly invested in a 1400 MW cable to Germany, named the Nord.Link project. Cable connection to the UK, which is part of the North Sea Network project, has also been licensed from the Norwegian government. Statnett is the owner of both connections on the Norwegian side and working with TenneT in Germany and National Grid in the UK. TenneT and National Grid is the owners on the opposite side. Both are TSOs in their respective countries. Nord.Link is planned to become operational in 2020, while the cable towards UK is scheduled operational in 2021 [15].

The cables will in many ways contribute to security of supply, for Norway particularly in dry years, and a more efficient use of resources. Trading opportunities will contribute to better conditions for unregulated renewable power production, including unregulated Norwegian hydropower. It is a contribution to a more climate friendly energy sector, and to encourage a higher and more easily way for trading partners to utilize renewable resources. Statnett's analysis shows that the economic profitability of increasing trade capacity is both high and robust. The main reason is that the cables contributes to more efficient use of resources such as power flows from the country with the lowest price to the country with the highest price. Additionally, Statnett claims this gives high economic benefit across a broad spectrum of possible future scenarios [16].

Overview - Operational characteristics

Finally, to summarize and give the reader an overview over important characteristics of the various generating technologies in this study, they have all been listed in Table 3.

Table 3. Operational characteristics of dispatchable technologies [12].

	Nuclear power plant	Coal fired power plant	Gas fired power plant - peaker	Hydropower / PSHP
Duty cycle	Base load	Base load	Midmerit / Peak load	Base load / Midmerit
Quick start	No	Yes	Yes	Yes
Daily start up	No	No	Yes	Yes
Load following	No	Yes	Yes	Yes
Frequency regulation	No	Yes	No	Yes
Black start	No	No	Yes	Yes

2.2 Generation based on fossil fuels - fuel price and carbon tax scenarios

It is interesting how the world will face the upcoming environmental challenges. Especially how the raise in energy demand will be solved when also a need of decrease in fossil fuel usage is desired and absolutely necessary for a sustainable future. Most certainly, it will affect future prices for fuel with carbon content.

The prices changes with time, across fuels and across sectors. The price paths can vary because of different strength in policies when it comes to address energy security and to fight environmental changes. Moreover, the price prognoses for the future can be hard to predict, and many international organizations have done comprehensive studies related to this topic. Nonetheless, due to limited amount of time, only one source is taken into account. This is from the prominent International Energy Agency who are the author behind World Energy Outlook (WEO) 2014. WEO 2014 serves prognoses and trends for market development for various energy related subjects. International Energy Agency is an autonomous agency whom support global collaboration on energy technology. Their work, WEO 2014, is a reliable reference. The fuel prices and carbon taxes predicted are through three different scenarios which are shortly explained below before the prices are introduced.

The Current Policies Scenario takes the assumption “business-as-usual”. Only formal adopted policies and implementing measures that are present by mid 2014 are taken into account in this forecast. As a result of this, the different environmental goals and emission targets are not met in the year of 2050. This is a scenario of how the fuel and carbon costs will look like based on current conditions.

The New Policies Scenario takes into account the policies and implementation measures that will affect the energy market in the future. Policy proposals and other forecast of development are implemented, even though measurements have not been fully developed. This regards supporting of renewables, efficiency development, alternatives to fossil fuels and vehicles.

The 450 Scenario adopts the outcome that the international goal of an average temperature of 2 degrees Celsius is met in 2050. It assumes that policies we have today will most certain change due to the different environmental goals and targets chosen. The scenario suggests prices that probably will be presented in upcoming years to reduce greenhouse gas emissions in the quantum that are necessary. The content of greenhouse gasses in the atmosphere peaks in the middle of this century (450 ppm). It is assumed that in the year of 2100 the level stabilizes with 450 ppm. Therefore the 450 Scenario.

WEO 2014 indicates that demand of energy related services are affected by the prices related to them. With increasing costs of fossil fuels, the demand for it will decrease.

Natural Gas

The relative cost of fuels and technologies are reflected by the price of the service, which again strongly influence the demand for any energy related service. If one makes the assumptions of equal conditions except fuel price, a raise will depress demand for it. Also, the same effect will give larger supply ability.

In each of the three scenarios presented, IEA have used iterative modelling exercises to achieve international energy prices, substituted with assumptions about cost of supply of various fuels. Furthermore, the three different scenarios take different price paths. The reason is related to the differences in the strength of policies of energy security, environmental challenges, and further the impact this has on supply and demand. Current Policies Scenario has definitely the highest price of fossil fuel import, since today's policies of excluding fossil fuels are limited and the current raise in the demand and supply situation. This push the prices up. The other scenarios are using a limited production rate of energy resources, leading to less need of fossil fuel and therefore avoiding the extra high fossil fuel cost from resources in the upper supply cost curve. The 450 Scenario gives the lowest prices, actually decreasing from 2013. The IEA suggests the following prices for upcoming years for Europe imports.

Table 4. Natural gas, Europe imports. Real terms prices 2013$/MBTU [17]

Scenario / year	2013	2020	2030	2040
450	10.6	10.5	10.0	9.2
Current Policies	10.6	11.5	13.2	14.0
New Policies	10.6	11.1	12.1	12.7

Steamed Coal

As for natural gas, the price paths for coal can remind of the paths for natural gas. The prices from the 450 Scenario are decrasing, while the prices from Current Policies Scenario are increasing the most.

Table 5. Steamed coal, Europe imports. Real terms prices 2013$/tonne [17].

Scenario / year	2013	2020	2030	2040
450	86	88	78	77
Current Policies	86	107	117	124
New Policies	86	101	108	112

Carbon taxes

The cost of CO_2 emissions will raise in upcoming years. Carbon taxes and cap- and trade schemes are some of the regional and national initiatives to lower emissions of one of the largest contribution to greenhouse gases in the atmosphere. These policies are spreading worldwide, and carbon taxes are becoming a normal charge to limit environmental pollution.

The scenarios from WEO 2014 has also forecasts for the carbon tax level for the future. The tax level can vary to a large extent. Obviously, for the 450 scenario reflects the high penalty that will come from releasing CO_2 to the environment.

Table 6. Carbon taxes. Real terms prices 2013$/tonne [17].

Scenario/year	2020	2030	2040
450	22	100	140
Current policies	20	30	40
New policies	22	37	50

As one can see from the Table 6, the prices is most definitely lower in 2020 and increasing significantly during the decades. In the 450 scenario, the raise is actually 536 percent in 20 years! In other words, if the world are going to mitigate the environmental challenges, huge consequences for use of fossil fuels will, and must, be implemented. The last ten years the raise is “only” 40 per cent.

Nuclear fuel - Uranium

When it comes to fuel costs for nuclear plants, this is a minor proportion of the generating costs. It has given nuclear power production an advantage compared with coal and gas fired plants. However, uranium has to be processed, enriched and fabricated into fuel elements. Actually, close to half of the cost of uranium comes from the enrichment and fabrication.

The WEO 2014 does not give any estimates for the nuclear fuel price development itself. Still, history shows that on an energy equivalent basis, nuclear fuel costs range from 4.4 €/MWh to 7.05 €/MWh in the period of 2000 to 2012. Without giving a total overview, the WEO 2014 assumes 10 $/MWh (8.8 €/MWh) produced electricity in 2040 in the 450 scenario [1]. This price has been chosen as the base value for the nuclear fuel price raise in the LCOE calculation explained later.

3 LEVELIZED COST OF ELECTRICITY

3.1 LCOE METHODOLOGY

For the comparison between different generating power plants and their costs, the method of levelized cost of electricity (hereinafter LCOE) is often used. LCOE is a convenient measure that summarize the overall competiveness of several different generating technologies. LCOE represents the per kilowatt hour cost of building and operating a power generating plant over its lifetime and duty cycle. LCOE is expressed in net present value terms, which means that all predicted future costs and generation are discounted to a specific date. It can in a more precise way be defined as “the ratio of the net present value of total capital and operating costs of a generic plant to the net present value of the net electricity generated by that plant over its operating life” [18].

There are many different ways of calculating LCOE. It is a controversial debate, and different sources and experts refers to various input assumptions, what costs to add or to not include, and more. Therefore, this report is supposed to give an overview and reflection on principles and requirements of LCOE calculations. Nevertheless, it will give an understanding of the differences between methodologies that are used in the energy business.

Advantages

One of the major advantages of the LCOE method is the final single aggregated value that can serve as a proxy. The LCOE method can be used to compare cross technologies even though they have different cost assumptions and structures. Key parameters and assumptions can be adjusted, regarding site specifics or differences between realities in the local and regional market. It is a wide used strategy and for several decades it has been an important value for comparison between different power generating technologies.

Drawbacks

Unfortunately, the LCOE method does not give an introduction to the financial performances in the different stages of a project’s lifetime. For this, it is necessary to obtain a comprehensive analysis of the cash flows. Here, both costs and revenues may not necessarily be fixed over time, but vary due to different conditions in market, like energy availability, demand and so on. There can be large variations in production profiles, and also large differences in market value of the supplied energy. In other words, LCOE approaches will not adequately account for market realities given as uncertainties and the dynamic change in price. Furthermore, the level of energy security and environmental sustainability are not addressed between the technologies in the methodology. This is some of the drawbacks of the LCOE method.

It is also worth mentioning that LCOE alone is not enough to make a conclusion about the extent of profitability or how the project respond to the competition to other projects. To make investment decisions, other parameters are needed in addition. For example, net present value, internal rate of return, among others. In addition, some of the different departments, institutes and others who works with these kinds of cost investigations, like the LCOE methodology, have added some additional technical parameters in their LCOE study to contribute when discussing the power generating alternatives. The parameters are linked to their availability, what cost would run if the project was not present, and several other factors. The different parameters, and more, are presented in Chapter 3.2.

Basic requirements

The LCOE can also be announced as the minimum price the electricity has to be sold for to make sure that the whole investment made pays of for the investor. Similarly, the LCOE can be a reference when considering support level (subsidies) for different renewable power plants in particular. This if the objective is to encourage an investment that can be both necessary for further renewable energy production commitment, and without providing overcompensation.
Levelized cost of electricity are in most cases given in this “common” expression

$$LCOE = \frac{\sum_t \frac{\text{Investment}_t + \text{O\&M}_t + \text{Fuel}_t + \text{Carbon}_t + \text{Decommissioning}_t}{(1 + discount\ rate)^t}}{\sum_t \frac{\text{Electricity}_t}{(1 + discount\ rate)^t}}$$

Table 7. Parameter overview in the expression of LCOE.

Parameter	*Information*
t	Year of lifetime [0,1,2,..]
Electricity	Electricity: Produced quantity of electricity in the respective year [kWh]
Investment	Investment in year t
O&M	Operational and maintenance cost in year t
Fuel	Fuel cost in year t
Carbon	Carbon cost in year t
Decommissioning	Decommissioning in year t
Discount rate	Discount rate
*	The expression is from International Energy Agency, IEA, and is shown in later section

These parameters are often the basic and most common input data in the LCOE expression, but the price level can vary to a large extent. Besides this, several additional parameters and input data can be added in the LCOE expression. These will be pronounced later in this report.

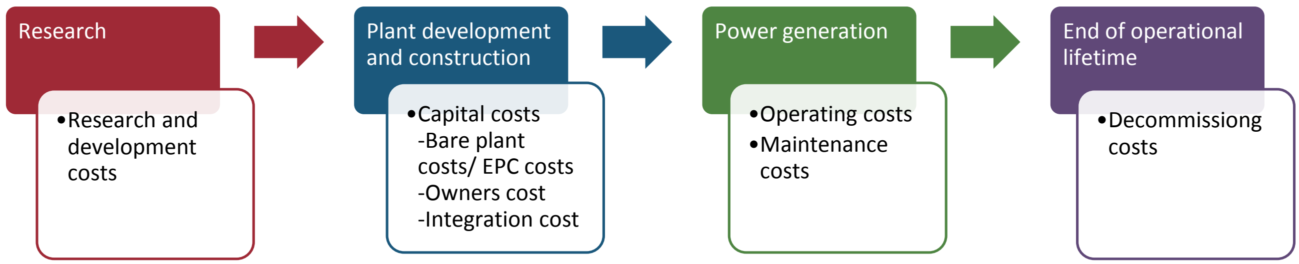

Figure 5. Cost categories in the LCOE methodology.

Differences in cost structures

It is a fact that investment of newer renewable energy technology is higher compared to the investment of conventional technologies, like gas and coal fired power plants. On the other hand, when it comes to yearly variable costs in operating and the different fuel costs, the renewables triumphs. Intermittent renewable wind and solar energy production have no fuel cost, while prices for gas and coal are high. Furthermore, the carbon prices related to them will also rise in upcoming years.

Discounting Energy?

To discount the generated electricity may seem incomprehensible, since physical units neither change magnitude over time, nor do they pay interest. This intuition, however, must in some way be qualified. The main idea is that the amount of energy generated corresponds to earnings from the sale of the same amount of energy. In this way, the value of the output is discounted rather than the output itself. To understand better, one kWh produced this year is not worth the same as one kWh produced one year later. The longer the revenues are displaced in the future, the lower the cash value. The total annual expenditure over the lifetime in operation includes the investment and operating cost accumulating over the operational lifetime.

Challenges

The quality of the input data and the level of detail are heavily affecting the result of the LCOE. To find a LCOE that have taken the dynamic behavior in the different development of technology costs into account is a tough challenge. It makes it hard to ensure reliable future prognoses. Actually, some investors are holding back information about real cost of a project which makes the accuracy even more difficult to obtain [19]. There are a lot of uncertainty in the prognoses, and different sources claims different forecasts of prices and costs. As a result of this, some sources calculates an upper and a lower values of the LCOE. Here, cost technology, energy availability, load factor and more are altered to give a full picture of how LCOE may turn out.

The input data can be uncertain and most volatile during the operational lifetime of the plant. As an example, it can be difficult to estimate the electricity output. The development in the electricity market, other technical aspects and development in society will also make contribution to future power demand. The estimation of future cost levels can vary across Europe, even with same technology and project configuration.

Policy preferences are also an interesting topic and crucial for what kind of investment that are, and in the future will be, preferred in the energy business. Subsidies and tariffs may be different from one technology to another, plant size and site qualities. They may be the critical points that results in renewable energy investment or choice of conventional power production.

3.2 LCOE METHODOLOGIES BY SOURCE

As mentioned, the LCOE methodologies may differ from one to another. In this chapter, the LCOE methodology from four sources have been analysed. In general, information given here are related to how the authors describe the cost calculation methodology, the level of detail given, and additional parameters discussed.

3.2.1 Department of Energy & Climate Change

The Department of Energy & Climate Change (DECC) are responsible for energy security in the UK and thereby working for having a secure and clean energy supply. DECC has the interests of international commitment, by promoting action in the EU, to mitigate the climate challenges and to reach the goals of 2020 by raising the renewable energy power production. The department have also different priorities concerning support in the UK's energy infrastructure and to keep the energy legacy safely and cost effective [20]. The study from DECC considered is "Electricity Generation Costs", from 2013 [18].

Cost calculation methodology

The levelized cost of electricity formulas are given as

$$Net\ Present\ Value = \frac{\sum_n total\ opex\ and\ capex\ cost}{(1 + discount\ rate)^n}$$

$$Net\ Present\ Value\ of\ Electricity\ Generation = \frac{\sum_n net\ Electricity\ Generation}{(1 + discount\ rate)^n}$$

$$Levelized\ Cost\ of\ Generation = \frac{NPV\ Total\ Cost}{NPV\ of\ Electricity\ Generation}$$

where n denotes time period.

Capital cost includes pre-development, construction and infrastructure costs. The costs of construction and infrastructure are adjusted over time. Financial costs are divided into fixed and variable operational costs, insurance, connection costs, carbon costs in terms of transport and storage, cost of emission and fuel prices. Furthermore, heat revenues (CHP) are being subtracted, so cost of electricity are the only thing being considered.

The capacity of plant, expected availability, efficiency and load factor are values that are estimated. All plants are assumed to run a base load generation with high load factor. Some of the renewables have load factors that reflects that they behave as intermittent resources.

DECC claims that it is more appropriate to use a range of cost estimates instead of point estimates, due to highly sensitivity in the values related to capital costs, operating cost, fuel costs, carbon costs and carbon transport and storage (CCS) costs. Load factor and discount rates are also important assumptions affecting the final LCOE. These mentioned values are given as a high, central and low values.

Level of detail – technological differentiations

The sensitivity analysis have been done by changing some of the values. DECC's case studies includes high capex, high capex high fuel, low capex low fuel, and low capex.

DECC has done the analyse by considering a total number of 56 different plants. Renewable generation alternatives includes wave, tidal stream shallow/tidal stream deep/ tidal range, biomass conversion, offshore wind, onshore wind, large scale solar, bioliquids etc. Some power plants considered has a variety of capacities, like hydropower <15 kW and hydropower 100 – 1000 kW. From the conventional types, various gas, coal and nuclear power generating alternatives are presented. In other words, it is a comprehensive study by DECC.

DECC have investigated the result of having power plant commissioning in different years, and differs between projects by choosing project start up in 2013 and 2019. Commissioning of the power plants set to be 2014, 2016, 2020 and 2025 and 2030.

Discount rates for the rated technologies are 10 per cent. DECC claims that comparing levelized cost estimates across technologies at this level will make the estimates neutral in terms of financing and risk.

Additional Parameters

DECC operates with the expression first of a kind (FOAK) and Nth of a kind (NOAK). NOAK are estimates that represents established technologies, and the power plant is one of several of its art. FOAK is defined as the first kind of its type within the UK, and cost related to these types of plants are obtained from the international business. The different calculation of LCOE has various assumptions based on if the plant is a FOAK or a NOAK. The plants are a mixture of NOAK and FOAK.

The cost estimates are given in general terms instead of site specific. System charges are taken into account but on an average basis.

DECC emphasizes in their study that some of the costs, like insurance, connection and UoS charges and CCS costs, are not absolutely necessary costs to include. Still, the cost parameters are included in their calculations.

Excluded from study

DECC states that grid connection costs are not included in their LCOE calculation. Furthermore, the costs of having back up reserves, when intermittent energy are being considered, are also mentioned being excluded. System balancing and network investment, impacts on environment and emissions are also not taken into account. DECC claims these are wider costs that may fall to others then the owner/operator of the power plant. There are some network related cost (UoS), but cost of market integration are not included. Finally, DECC points out that LCOE relates only to the cost that affects the owner/operator. It does not consider revenues during its operational lifetime, like sale of electricity or other revenues.

Table 8. Parameters included in calculations of LCOE from DECC.

Parameter	***Included in LCOE***	***Information***
Site specific	No	
Land cost	Yes	Part of infrastructure costs.
Investment	Yes	
Planning	Yes	Part of pre-development. To demonstrate sensitivities DECC gives high, medium and low cost estimate.
Capital costs	Yes	To demonstrate the sensitivities, capex cost in the LCOE calculation are given in both higher and lower level. High, medium and low cost estimates.
Operation and Maintenance costs	Yes	
Fuel cost	Yes	To demonstrate the sensitivities, fuel costs in the LCOE calculation are given in both higher and lower level.
Carbon cost	Yes	The carbon price assumed is at the level of the Carbon Price Floor, which DECC claims is assumed to stay flat in real terms beyond 2030 at £76/t in 2012 prices. This equals 109 2014€/t.
Grid connection cost/ Grid reinforcement	Yes	Connection cost and use of system charges.
Network cost	No	DECC mentions that LCOE does not cover wider costs such as network upgrades. These may in part fall to others.
Cost of market integration	No	The methodology does not take impacts on the wider electricity system into account.
Decomissioning cost	Yes	Cost of decommissioning and waste, which is only credited nuclear power.
Other parameters		
Load factor		All non renewable (except OCGT) assumed baseload with high load factor.

3.2.2 Fraunhofer Institut

Fraunhofer Institute for Solar Energy Systems (ISE) is the largest solar energy research institute in Europe. Technology research and studies of efficient energy supply, with an environmental motive, is one of the major interests of the institute. Fraunhofer developes different materials, components, systems, and works with the industry process development of solar energy usage. In addition, Fraunhofer Institut works with electrical power supply, energy storage and rational use of energy, among others [7].

Fraunhofer has done a careful and detailed calculation of levelized cost of various power generating technologies in a study named "Levelized cost of renewable electricity – renewable energy technologies". The study predicts future cost development through learning curves and market scenarios.

Solar, wind and biomass technology are the main focus in their report. As reference values, new conventional power plants where discussed and compared like various coal and gas fired technologies. Furthermore, Fraunhofer ISE presents analysis of future market development and analysis of the situation that are present.

Cost calculation methodology

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{A_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{M_{t,el}}{(1+i)^t}}$$

The annual total cost A_t consists of annual fixed and variable operational costs, maintenance and repairs, service and insurance payments. Additionally, one may subtract the residual value, if any, or add the cost of the disposal of the plant.

The investment cost and fuel prices are given in upper and lower values. This is in order to represent the variation in market price, and the differences in full load hours.

In the LCOE calculation, Fraunhofer varies the different costs, like investment, fuel cost, cost of CO_2 emission allowances and load hours. Fuel prices and CO_2 emission allowances changes with time, and also, power plant efficiencies are assumed rising. The efficiency rates for each technology are given in low, medium and high values.

Fraunhofer Institut claimes the LCOE values shrinks over time due to innovations in the technological field. Cheaper material, higher level of material performances, higher efficiency in production processes and systems in general, and also more automated mass production of different components. Several types of cost will therefore most certainly shrink in the upcoming years [7].

Level of detail – technological differentiations

The LCOE calculation from Fraunhofer are site specific. One technology can have several capacities, and together with several site conditions accounted for makes the study very detailed. Regarding solar power production, both ground mounted utility-scale and small rooftop power plants are considered. Depending on location, different insolation forecasts have been used. Depending on where in Germany (north – south) this can differ very much, but also some insolation forecast from areas in Spain have also beengiven to distinguish between the LCOE values for sites with favorable conditions and areas with lower solar irradiation. This contributes to the upper and lower LCOE values.

There are different conditions and factors that makes the calculation of the LCOE more difficult. Fraunhofer Institut mentions state and federal tax credits, the availability of various incentives and rules governing private use for example. It is an uncertainty about these different factors. Their values can vary due to different locations and with time. Both change in fuel prices and technology development will cause a different situation compared to what may have been expected.

Excluded from study

The changes in terms of financing related to framework conditions changes during the projects lifetime have not been considered. The different national economic evolution is a hard to predict. Therefore, it is assumed that this kind of forecast will just give the LCOE an "additional, not-technical-specific uncertainty". Fraunhofer also mentions that the load following operation capability has been excluded from the LCOE calculation, and also the availability depending on time of the day.

Additional Parameters

Learning curves

Franhaufer Institut supplies the calculation of the best economic alternative of energy generation technology with learning curves for the different power generating technologies. These learning curves come from the market projection through upcoming years (2020 and 2030). The learning curves predicts the future prices in the market and costs for the various power plants, and will therefore affect LCOE as well.

The concepts of a learning curve is that it represents a relationship between the sinking unit cost (production cost) and the cumulative produced quantity(market size). For example, if a number of units doubles and the cost sink by 20 per cent, the learning rate will corringspondly 20 per cent. The relationship between the quantity x_t produced at time t, the costs $C(x_t)$ compared to the output quantity at reference point x_0 and the corresponding costs $C(x_0)$ and the learning parameter b can be presented as follows:

$$C(x_t) = C(x_0)(\frac{x_t}{x_0})^{-b}$$

$C(x_t)$ - Cost at time t
$C(x_0)$ - Cost at reference point
x_t - quantity produced at time t
x_0 - reference point
b - learning parameter

$$LR = 1 - 2^{-b}$$

The forecast for plant prices $C(x_t)$ for the period studied by means of the learning curve model it is possible to calculate the LCOE up to 2030. Here, it is made assumptions of using literature values and/or Progress Rate (PR = 1 – learning rate).

Table 9. Parameters included in Fraunhofer ISE calculations of LCOE.

Parameter	***Included in LCOE***	***Information***
Site spesific	Yes	Germany (north, south), Spain.
Land cost	Yes	
Investment	Yes	Information based on current power plant and market data. Several technologies for each energy source, very specific.
Planning	Yes	
Capital cost	Yes	
Operation and maintenance costs	Yes	
Fuel cost	Yes	Road maps and several sources to find an upper and a lower fuel price up to 2050.
Carbon cost	Yes	Road maps and several sources to find an upper and a lower fuel price up to 2050.
Grid connection cost/ Grid reinforcement	No	
Network cost	No	
Cost of market integration	No	
Decommissioning cost	No	
Other parameters		
Load factor		
Learning curves		
Efficiency		Made an estimation over efficiency development in the different power producing entities. Assuming a raise in energy conversion for conventional technologies.
Shrinking electricity output		For renewables, annual reduction of 0.2 per cent of electricity output.

3.2.3 U.S. Energy Information Administration

U.S. Energy Information Administration (EIA) is an agency of the U.S Federal Statistical System. Their work is to collect and analyse energy information, and to scatter information to promote public understanding, right policymaking and efficient markets. EIA is part of the U.S. Department of Energy. The report considered is “Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014”.

Cost calculation methodology

EIA has done a proper investigation on the LCOE for a range of technologies. The costs that are considered are capital cost, fuel cost, fixed and variable operational and maintenance costs and financing costs. Cost of transmission and the cost of grid upgrades are included when there are need to invest in transmission lines to access remote resource. These costs are higher for wind and solar than for conventional technologies. The cost and numbers are obtained from the Annual Energy Outlook 2014 [17].

The dispatchable resources contains assessments of natural gas and coal fired technologies, nuclear, biomass and geothermal. Actually, five different sorts of natural gas fired power plants are evaluated. In the non dispatchable category, solar PV, solar thermal, wind, both on and offshore, and hydroelectric power production has been evaluated and presented.

EIA mentions it is inconvenient to compare dispatchable and non dispatchable resources to each other. The reason is that dispatchable resources are more valuable to energy systems. Dispatchable and non dispatchable generating technologies are therefore split in sections when LCOE is submitted. Capacity values, explained later, gives more detail about this topic. EIA choose to calculate the LCOE with and without subsidies. The availability of the various incentives, also including state/federal tax credits impacts the LCOE.

EIA uses a discount rate for the rated technologies of 10 per cent.

The LCOE values are based on the energy situation in 2019 and 2040. By 2040, the LCOE for most of the technologies are decreasing, reflecting a decline in capital costs over time. The cost of technologies are lower due to learning. The newer technologies decreases more than the conventional technologies. It is assumed a 30 year cost recovery. The cost recovery period does in reality vary between technologies.

Additional Parameters

Subsidies

The results in the study are given with and without subsidies. Subsidies are given for solar, nuclear, and geothermal. They are based on targeted tax credits. It only reflects subsidies available in 2019, based on Energy Policy Act of 1992 and 2005. Current laws and regulations are basic assumptions for how EIA models tax credits. The reason for why it refers to 2019 is that some technologies needs long lead time, and therefore the plant could not been brought online prior to 2019. It must have been under construction already otherwise.

Projected utilization rate

This is a rate which depends on load shape and mix of resources in a chosen area. EIA mentions the existing resource mix within a region is of huge importance when it comes to the economic viability of a project.

Capacity value

Depending on existing capacity mix and specific load characteristics for various regions capacity values are developed. These are values that represents the generation power plant importance to a system for being able to follow electricity demand, meaning if the technology is dispatchable or not. Dispatchable technologies have the ability to behave as a flexible power source and are rewarded for this by having a higher capacity value then non dispatchable technologies. An example are a conventional coal fired power plant given a capacity value of 85 per cent, while solar PV is given a value of 25 per cent.

Levelized avoided cost of electricity

The EIA claims that LCOE is not the optimal way to compare different electricity generation technologies. Levelized avoided cost of energy, LACE, reflects the cost of producing the electricity otherwise in another power generating project. It can be described as a proxy for the costs of a candidate project. LACE and LCOE will then be compared to each another, and it will give an indication of the value of the project exceeds it costs. If several technologies meet load, comparison of all LACE to its LCOE can be used to find the best net economic value, and thereby the best project option can be chosen. Actually, when the LACE of a certain technology exceeds its LCOE at a given time and place, that technology would from an economic point of view be attractive to build. Still, in real world, EIA emphasizes that other factors must be taken into account when planning power plant project realization.

It is a harder task to find levelized avoided cost than levelized cost. It will require more information about the system operational procedure when it is supposed to operate without the energy generation that is actually being evaluated. Avoided cost can be based on the energy and capacities marginal values that comes from adding a specified generation technology. It represents the project owner potential revenues from sale of electricity.

Learning trends

Over time, there probably be a cost reduction for various technology investments. Advanced technology from “newer” renewable technology will have a rapid cost reduction, while the conventional power plants technologies will have smaller learning effects. This is taken into account in EIAs calculation of LCOE.

Table 10. Parameters included in calculations of LCOE from U.S. Energy Information Administration.

Parameter	***Included in LCOE***	***Information***
Site specific	Yes	Regions in USA used to generate averages. Projected utilization rate reflects the load shape and the existing resource mix in an area given.
Land cost	Yes	
Planning	Yes	
Investment	Yes	
Capital cost	Yes	
Operation and Maintenance costs	Yes	
Fuel cost	Yes	Included in fixed and variable O&M.
Carbon cost	Yes	Included in fixed and variable O&M.
Grid connection cost/ Grid reinforcement	Yes	Grid costs included in “Transmission Investment”.
Network cost	Yes	To access remote resources and higher cost of necessary upgrades on solar and wind projects. Included in Transmission Investment.
Cost of market integration	No	
Decomissioning cost	No	
Other parameters		
Load factor		Baseload at the plant level.
Capacity Factor		Determines the availability to run the power plant if necessary. Differs a lot between intermittent and flexible resources. The calculations are based on averages of the capacity factor for the marginal site in each region.
Utilization rate		Depends on load shape and mix of resources in a chosen area.
Levelized Avoided Cost of Electricity (LACE)		As an additional parameter to LCOE. Not part of the LCOE calculation itself. An additional cost parameter for additional information about generating alternative.

3.2.4 International Energy Agency

The International Energy Agency (IEA) is working for energy security in member countries. This is done through collective response to physical disruptions in oil supply, and to further advice members on energy policy. IEA have several other tasks, and the agency aims to support collaboration on energy technology to secure energy supply in the future. Mitigation of environmental impact and solutions to worldwide challenges through engagement and dialogue between the agency, the industry, international organizations and other non member countries are also of huge importance. Further, promoting sustainable energy policies that stimulates economic growth and environmental enhancement. The report from IEA considered is the “Projected cost of generating electricity - 2010 Edition”.

Cost calculation methodology

$$P_{elecricity} = \frac{\sum_t \frac{\text{Investment}_t \ + \ \text{O\&M}_t \ + \ \text{Fuel}_{\ t} + \ \text{Carbon}_t + \ \text{Decommissioning}_t}{(1 + discount\ rate)^t}}{\sum_t \frac{\text{Electricity}_t}{(1 + discount\ rate)^t}}$$

IEA’s report contains data on electricity generating costs for nearly 200 power plants in 21 countries. The technical and economic parameters in the LCOE calculation is done using generic assumptions that the Ad hoc Expert Group on electricity generating costs have agreed upon.

The IEA provides two LCOE calculation, divided in Part 1 and Part 2. Part 1 uses “common” methodology rules. The data are provided by organizations and participating countries. The different data and information were received for a range of fuels, energy sources and technologies. Here nuclear, coal, gas, biomass, hydro, solar, on and offshore wind, wave and tidal are being investigated. Part 2 gives a sensitivity analysis, that shows the impact on LCOE when the discount rate, cost of fuel or construction, load factor and lifetime is altered. IEA introduces the parameters by dividing them into five basic modules they use in a spread sheet model. The modules are divided into identification, basic assumptions, questionnaire information, generating costs and lifetime generating costs.

1. ***Identification***: specific country, fuel category, technology and type.
2. ***Basic assumptions***: capacity, load factor, the lifetime of the plant and the discount rate, fuel price and carbon price.
3. ***Questionnaire information***: costs of pre-construction, construction, contingency, refurbishment and decommissioning, as well as fixed and variable operations and maintenance cost, fuel, carbon and waste management. The entries stretches from the beginning of pre-construction, through 2015 (commissioning) until 2085 (end of decommissioning for nuclear power plants).
4. ***Generating costs***: LCOE per MWh electricity.
5. ***Lifetime generating costs:*** total discounted generating cost as well as LCOE over the lifetime in a synthetic manner.

The LCOE is calculated with a 5 and 10 per cent discount rate. As other sources, IEA states LCOE are sensitive to the discount rate and slightly less sensitive to prices of CO_2, natural gas and coal. For the renewable technologies, load factors for different sites and countries affects the LCOE to a certain point. Furthermore, the LCOE are calculated as the levelized cost of baseload generation at plant level.

Excluded from study

The study excludes the cost of transmission, distribution and other impacts on the electricity system. IEA only takes cost for society to build and operate a power plant. Taxes and subsidies are excluded. IEA mentions this may be a shortcoming of the study.

IEA emphasizes that when intermittent load is being evaluated, cost of hydro reserves or peak gas turbines should, in principle, be added to the LCOE calculation when comparing their LCOE to dispatchable technologies' LCOE. Unfortunately, there are little information and studies related to this topic and are therefore not taken part of the calculations method from IEA.

Additional information

IEA points out the healthy competition between the different technologies. National preferences and the advantages attached to different regions will help in decision making procedures. The number of choices of available technologies alternatives have never been higher, and the pressure led upon operators and providers of technology have never been so intense.

The study from IEA gives insight to the 21 countries' costs of generating technologies, and also states the limitations of the methodology and the generic assumptions that are used. Different national policies and, if there is, encouragement or discouraging related to certain technologies may affect the level of risk for the various investors.

In spite of all uncertainties mentioned, the IEA report points out that LCOE methodology is a most useful basic reference. To some, this might be a defensive way of describing the LCOE methodology, but in fact, this is not a weakness. IEA emphasizes there are simply no good alternative to the LCOE method, and it is not a shortcoming that there are so many uncertainties that affects the result. Actually, IEA states it gives rather an idea over how complex the electricity world is. It is also worth mentioning that policy makers, academics and other authors need benchmarks for discussion. LCOE serves as a good proxy for this.

The study concludes that there are no electricity generating technology that alone can be the cheapest in all kinds of situations. Key parameters and the circumstances of each project will be important. Finally, financing cost, CO_2 and energy policy like security of supply, energy market development and emission reduction of carbon will make contributions to the choice of preferred technology.

Table 11. Parameters included in calculations of LCOE from International Energy Agency.

Parameter	***Included in LCOE***	***Information***
Site specific	Yes	21 different countries are investigated in this study.
Land cost	Yes	Country specific.
Equipment	Yes	
Investment	Yes	
Planning	Yes	
Capital cost	Yes	
Operation and maintenance costs	Yes	
Fuel cost	Yes	
Carbon cost	Yes	Concerning CCS, only carbon capture and compression are included. Not storage.
Grid connection cost /Grid reinforcement	No	
Network cost	No	
Cost of market integration	No	
Decommissioning	Yes	
Other parameters		
Load factor		Base load at plant level.

4 METHODOLOGY AND CASE STUDY DATA

Calculation of energy costs are made for a variety of power generating technologies. The calculations are performed in the greatest extent possible from a number of general assumptions and limitations described in this chapter.

4.1 LCOE - SPREADSHEET MODEL

The LCOE spreadsheet model is available on computer-file. The model is made both for this work and for general usage to imagine different scenarios in the energy system for the future and to see how they will affect the LCOE. It is designed in such a way that it is easy for the user to compare the levelized cost for the various technologies to each other. For information on how to easily use the spreadsheet model, see Appendix A.

The model is based on up-to-date information. The cost per year is based on price development, which means it accounts for raise in fuel prices and carbon taxes. The costs changes per year, and this is accounted for in the calculation. In other words, the numbers are not yearly averages.

The technologies included in the spread sheet model are

- Hydropower
- PHSP
- Nuclear power
- Gas - CCGT
- Gas - CCGT with post combustion CCS
- Gas - OCGT
- Coal - ASC with post combustion CCS
- Coal - ASC with oxy combustion CCS
- Coal - IGCC with post combustion CCS

4.1.1 Data sources

Cost estimates and technical parameters used as inputs was obtained from a number of sources. A lot of information are from Parsons Brinckerhoff and Department of Energy and Climate Change, which are both reliable sources when it comes to LCOE calculation for various generating technologies. They have several years in the business and with these kinds of studies.

Estimates were also based on a combination of technical modelling from studies like the prominent World Energy Outlook 2014. Estimates on fuel prices and carbon taxes has been fully adapted from WEO 2014. In addition, information about nuclear fuel prices has been collected from WEO 2014.

NVE is also an important source for cost analysis of hydropower and PSHP systems. NVE has done a comprehensive study about costs in Norway, which is used in this model since the essential meaning is to look into Norway's ability to operate as a flexible battery for Europe [21]. The costs from NVE are very different from cost data from Parsons Brinckerhoff. This comes from the earlier mentioned reason of

Norway's favorable conditions for hydropower development. In addition, this study is based on the cost of upgrading already existing hydropower facilities in Norway. Obviously, this makes the investment cost lower than the costs of building new power plants. This is explained further later on in this chapter.

4.1.2 General approach

For each of the chosen parameter, high, central and low input values was incorporated into the spread sheet model. These different levels have been utilized to represent the differences in every parameter across some specific example sites.

The values gathered from Parsons Brinckerhoff are NOAK power plants. This means that the technology are well-proven and the costs reflects these circumstances. Commissioning is set to 2020 for all technologies.

Discount rate

In the model, a discount rate of 4 per cent have been used. This equals the discount rate recommended in the NVE study of costs in the energy business, typically for governmental investment of 40 years [21]. Usually, the rate of return in individual projects will vary to a large extend depending on a range of factors, not least the framework conditions that affect both the cost and revenue side. The discount rate should make the estimates act neutral in financing and risk terms. This is especially important when comparison is made across technologies.

In spite of this, the focus of this report, however, has been to look only at the costs related to individual technology and their electricity production over its operational lifetime. The purpose of choosing equal return rate have been letting only these factors be the driving force for differences in energy costs.

A standard of 10 per cent discount rate have been used in the previous introduced LCOE studies, in line with the "tradition" used in analysis from some organizations. It is therefore being included in one of the case studies for the reader to see the differences, and also to get an impression of how sensitive LCOE is to discount rate.

Currency and inflation rate

All prices and costs have been translated into 2014€. This is done by using an inflation rate of 2.3 per cent per year. The currencies used here are given in Table 12, and obtained from Den norske Bank, DnB, in February 2015.

Table 12 Currency used in LCOE spread sheet model

Currency	*Norwegian kroner (DnB)*
1 USD $	7.61 NOK
1 GBP £	11.78 NOK
1 Euro €	8.63 NOK

4.1.3 Costs included in the LCOE – spread sheet model

The spreadsheet model has taken this formula, which is based on IEA's formula, only adding cost of pumping due to the calculation of PSHP's LCOE.

$$LCOE = \frac{\sum_t \frac{\text{Investment}_t + \text{O\&M}_t + \text{Fuel}_t + \text{Carbon}_t + \text{Pumping}_t + \text{CCS}_t + \text{Decommissioning}_t}{(1 + discount\ rate)^t}}{\sum_t \frac{\text{Electricity}_t}{(1 + discount\ rate)^t}}$$

The parameters chosen to be part of the LCOE calculation are based on the previous section, LCOE – methodologies by source. The model is limited to only the most essential parameters. In the spreadsheet model, the reader can see the following parameters. Table 13 gives information about each parameter.

$$LCOE = \frac{\sum_t \frac{\text{Investment cost}_t + \text{Fixed cost}_t + \text{Variable cost}_t\ (+\text{Decommissioning}_t)}{(1 + discount\ rate)^t}}{\sum_t \frac{\text{Electricity}_t}{(1 + discount\ rate)^t}}$$

Table 13. Parameters in LCOE formula used in spread sheet model.

Parameter	*Information*
t	Year of lifetime [0,1,2,..].
Electricity	Electricity: Produced quantity of electricity in the respective year [kWh].
Investment cost	EPC costs; equipment cost (e.g. turbines, control systems), other investment and planning costs,construction/installation costs, foundations, land (access to land, purchase of land, administrative costs included in support).
Fixed costs per year	Fixed operation and maintenance costs, and cost of insurance and UoS charges.
Variable cost per year	Cost of fuel/carbon taxes/energy for pumping.
Decommissioning	Decommissioning in year t. Only for nuclear.
Discount rate	Discount rate.

Investment

The cost of investment is the one time cost of equipment, components, materials and installation of these. Project management related costs, cost of land, infrastructure, machine and electrical components, civil work are also all part of the investment in this model.

The investment is presented as overnight cost. This means that the cost of a construction project are as if no interest was incurred during construction. One can imagine the project was completed overnight. It can also be defined as the present value cost that represent the one time up front to complete the payment for a construction project like a power plant. The investment is stated in [M€/MW].

Table 14 shows the percentage of each subcategory of the investment. The cost percentage in the various technologies (gas, coal, hydro) can vary to some extent, but this is a most common approach. EPC cost means engineering-procurement-construction. This is the “bare plant cost”.

Table 14. Overview over cost components.

Component	***Percentage of capital cost***
Pre-licensing costs, technical and design	**2%**
Regulatory, licensing, public enquiry	**1%**
EPC cost (excluding interest during construction) – variability and uncertainty	**90-95%**
-Equipment/ Machines	*50-65%*
-Cost of building/ Civil work	*20-30%*
-Project management	*10-15%*
Infrastructure cost	**2-3%**

Fixed costs per year

Fixed costs per year are considered incurred whether or not the plant is generating electricity. This cost parameter is quoted as a percentage of the investment per year. This is favorable and an easy way to find the annual costs based on experience in the energy business. The costs that are included in “fixed costs per year” are fixed operation and maintenance (O&M) costs, which includes regularly cost of reparations, salary for operational staff, maintenance, rehab on access roads etc. The cost of insurance, network connection and UoS charges has been added in addition.

For gas, coal and nuclear power stations, the cost of connection and UoS charges has been generalized as much as possible based on the size of the plant and not the geographical location. This will most likely not affect the real situations, since these costs are not very different between the various plants that are being compared. As an example, usually, offshore wind experiences a large external cost due to necessary connection and network upgrades. Still, offshore wind does not take part in this study. The situation differ when it comes to Norwegian hydropower and PSHP systems, due to the necessary transmission connection to the continent.

An advantage with the cost added together and represented as a percentage are the number of uncertainties. Changing some of the values will in some cases "even up" due to lack of future trustworthy estimates. "Fixed costs per year" is given as one percentage that can be altered, and in this way easy to use in the model. For information, start up, shut down and no load costs are some of the costs related to operational cost that are not taken into consideration in the spread sheet model.

Variable costs per year

The variable cost per year can be related to what some in the energy business names variable O&M cost per year. The reason why it is called "variable cost per year" in the model is that the fuel, carbon and pumping costs are of a such large percentage of the cost parameter that they are chosen being the only contribution. All the maintenance costs are covered in the fixed O&M cost per year.

The "variable costs per year" are limited to costs of fuel, carbon taxes, and other operational costs that comes from electricity price for pumping hydro or CCS technology for those plant types with this installed. The different costs are presented below, and is found in the model where it is relevant.

The three mentioned scenarios for fossil fuel prices and carbon taxes from WEO 2014 are included in the spreadsheet model. Three results are given for each gas and coal power technology, each from one scenario. The prices given below are based on numbers presented earlier from WEO 2014. Here it is transferred into useful values in the model, where thermal efficiencies and carbon content in various fuel categories have been accounted for. For information, data related to energy content in fuels, used for calculations is from DEFRA [22].

Natural gas

Table 15. Price for natural gas 2014€/MWh(lhv)

Scenario / year	2014	2020	2030	2040
450	36.26	35.92	34.21	31.47
Current Policies	36.26	39.34	45.16	47.89
New Policies	36.26	37.97	41.39	43.45

For a total picture of the fuel price and for a thoroughly LCOE calculation, the price for each year between 2020, 2030 and 2040 are interpolated. The various gas burning power plants have an operational lifetime between 30 and 35 years. The prices between 2040 and 2055 in the spread sheet model are raising with the same intermediate as between 2030 and 2040. To get more information about the calculation, see Appendix B.

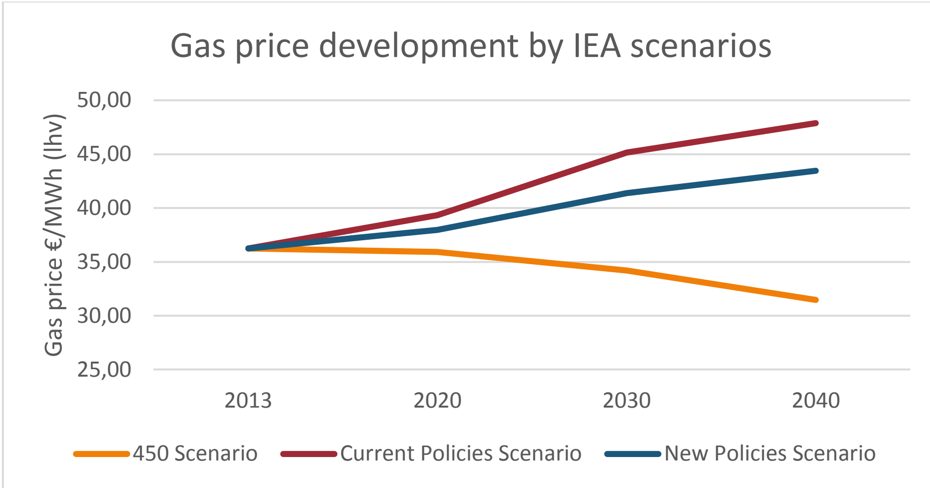

Figure 6. Gas price development by IEA scenarios.

Steam coal

Table 16. Steam coal prices 2014€/MWh by scenario.

Scenario / year	2013	2020	2030	2040
450	11.63	11.90	10.55	10.41
Current Policies	11.63	14.47	15.82	16.77
New Policies	11.63	13.66	14.61	15.15

The price for each year between 2020, 2030 and 2040 are interpolated. The prices between 2040 and 2050 in the spread sheet model are raising with the same intermediate as between 2030 and 2040. For more information, see Appendix C.

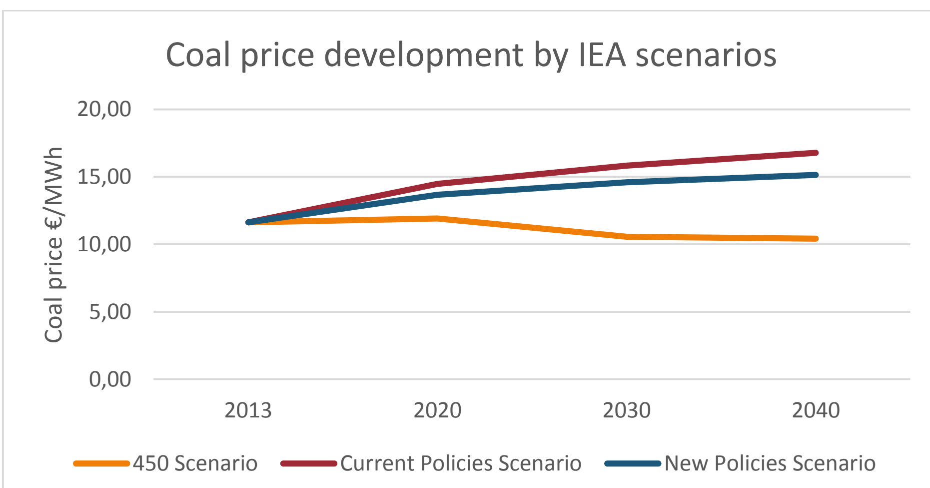

Figure 7. Coal price development by IEA scenarios.

Carbon taxes

Table 17. Carbon taxes 2014€/tonne.

Scenario/year	2020	2030	2040
450	19.85	90.21	126.29
Current policies	18.04	27.06	36.08
New policies	19.85	33.38	45.10

As for the fossil fuel prices, the carbon taxes between 2020 and 2040 have been interpolated. Between 2040 and 2055 in the spread sheet model are raising with the same intermediate as between 2030 and 2040. The total result are given in Appendix D.

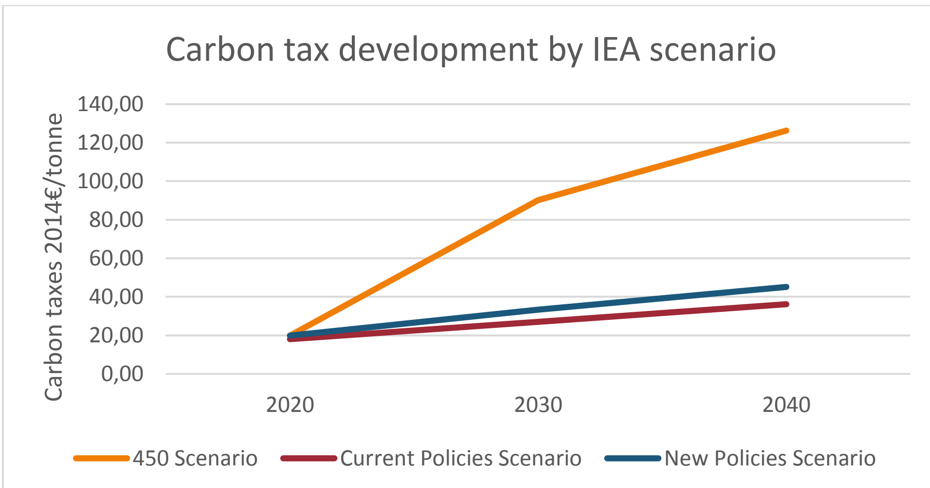

Figure 8. Carbon tax development by IEA scenarios.

The content of carbon is different for each type of fossil fuel. The information and data is taken from EIA [23]. For the result in €/MWh, see Appendix D.

Nuclear fuel

Current price development history and numbers from WEO 2014 have been used for nuclear fuel price estimates. WEO 2014 assumes 10 2013$/MWh (8.8€/MWh) produced electricity in 2040 in 450 Scenario. This has been chosen as the central value, and the price are assumed to raise linearly through the operational lifetime of the plant, which yields from 2020 to 2080.

Table 18. Nuclear fuel price estimates in 2014€/MWh.

	Level / year	***2020 [€/MWh]***	***2080 [€/MWh]***
Nuclear fuel prices	High	7	15
	Central	7	13
	Low	7	10

Even though high, central and low prices have been estimated, an early first calculation shows that the differences in these fuel prices are low, meaning the LCOE does not differ as much as expected. Only the central price estimate shown in Table 18 are therefore included in the LCOE spreadsheet model. The cost is given per MWh produced electricity.

Cost of Carbon Capture and Storage

For power plants with CCS, the costs are part of the “variable cost of the year” in the spreadsheet model. Usually, a high percentage of carbon are captured, often 90 per cent, while the rest is released to the atmosphere. The cost of CCS have been set to 26.8 €/tonne [24]. Carbon taxes are calculated for the amount of carbon released. Carbon dioxide content and net lhv efficiencies have been used to calculate the cost of CCS per MWh electricity generated. The carbon dioxide content information is from EIA [23]. For more information, see Appendix E.

Table 19. Cost of CCS.

Fossil fuel	***CCS Price [€/tonne]***	***Cost CCS [€/MWh]***
Gas CCGT w.CCS	*26.8*	*15.70*
Coal (all types)	*26.8*	*24.89*

The cost of CCS are assumed equal for each year of the plants operational lifetime.

Price of pumping and load factor

One may think that one can use the overproduction of electricity from solar and wind when this is available. Still, this is a way to optimistic assumption, and the price or electricity would have been zero in this case.

The most reasonable scenario might be to focus on the marginal cost of base load generation which in many cases will respond to spot price. In this case, in periods with producing low cost electricity from base load units it is reasonable for PSHP system to pump their magazines to a higher water level, storing a larger amount of energy in a cheap way. As a reference, one can use the marginal cost of producing electricity from a coal fired power plant, which is used to a large extent in Europe for base load activities. Gas and nuclear energy is also an alternative, but due to gas power plants often used through peaking hours, and the situation of fewer nuclear power plants in Germany, the choice was set to coal fired power plants. The marginal cost is in a "perfect market" are equal to spot price, which will be the pumping price in our case.

Intelligent Energy Europe had written a report on future electricity markets [25]. They have taken 4 different scenarios, where different assumptions and forecast of energy development are considered (NOPOL, HARMQUO,HARMFIT, NATFIP). Based on findings in this report, the marginal prices are divided into three. One is based on a pumping cost of 20 €/MWh. Next 30 €/MWh and the higher alternative reaches 40 €/MWh.

Additionally, numbers from NVE [21] have been used for comparison. With their assumed future energy price set to 29 €/MWh (0.246 NOK/kWh) one can assume the prices chosen in the spread sheet model are reasonable. Actually, when assuming only using electricity for pumping when prices are low, the cost of 30 €/MWh, which is an average, must be sufficient. PSHP systems will only be in pump mode when the prices is low, which is most cases is lower than an average value.

Prices are crucial for when the PSHP system will operate as a producing or consuming unit. The highest number of operation hours for the pump will be 50 per cent of the time, in other words, 4380 hours during one year. For choosing the hours the pump will operate, the model has taken into account to cover for losses. This means that if the load factor of turbine mode is 0.30, the load factor of pumping mode needs to be 0.30 divided by the total PSHP efficiency. As presented later, the model has an efficiency of 93 percent in generating mode and 80 per cent in pumping mode. The respective load factor for pumping then equals 0.40.

Costs of cabel and grid upgrades

The 1400 MW cable reaching Germany is included in the LCOE calculation of PSHP. This is related to the real situation appearing in 2020, when this cable is scheduled to be operational.

When taking into account the subsea cables, the cost have been collected from a license application from Statnett. The cost are divided between investment cost, O&M costs, insurance, transit costs and system operation related costs, like up and down regulation and frequency control.

The investment cost of the cables to Germany are € 764 million. The cost estimate is based on experience from previous projects in Statnett, including NorNed and SK4 together with investigations on future predictions. The yearly running cable related costs is set to count from 2020, which means the operational and other similar costs are starting from this year.

Grid upgrades are an interesting topic in the upcoming years. Due to the international power exchange, a lot of transmission lines needs to be upgraded or replaced in southern part of Norway. This is primarily costs related to necessary capacity expansions, or the fact that available capacity today will not be enough some years from now. Statnett has estimated a cost of 2 billion NOK related to the upgrades needed due the Nord.Link project, which equals € 242.5 millions. The last share is for grid upgrades related to the North Sea Network project (UK). It is assumed that domestic grid reinforcements is close to finished before commissioning and has a construction period of 3 years with steady costs incurred each year. These costs are not shared with partner. Moreover, Statnett has accounted for a reinvestment of the cables after 20 years. This means that a cost of € 9.8 millions will take place in 2040, when the cable have been in operation for 20 years [16].

The various cost of cable and grid cost are fixed, which means they will not differ due to change in capacity of hydropower plant or PSHP systems.

Decommissioning

Decommissioning is only included in the LCOE calculation of nuclear power. The reason for this are the huge cost of deposition of radioactive material. The cost are set to 350 M€ [26].

Energy production

The formula given below shows how the amount of generated electricity is found in the spreadsheet model. Hence, each individual power plants are generating the same individual amount of energy each year through the whole lifetime of the power plant.

$$Electricity\ generated = 8760h\ \times Load\ factor \times Availability \times Capacity\ [MW]$$

Load Factor

Because of the focus on flexibility in this report, the load factor used in some of the case studies are chosen by the author due to the higher share of electricity generation from renewables. The assumptions of lower production from conventional technologies makes therefore the load factor lower in some case studies than load factors used in the industry today.

4.2 Overview – costs and parameter values for individual technologies

An overview over the individual technologies is given in this chapter. The high, central and low costs and values of investment, capacities and load factors are presented. In addition, efficiencies, availabilities and operational lifetimes of the various plants are listed.

Gas fired technology

Table 20. Parameter values (high, central, low) used in spreadsheet model for gas fired technologies. Source: Parsons Brinckerhoff [24]. Capacities and load factors have been chosen by the author.

	Level	Cost of investment	Yearly fixed cost [% of investment]	Capacity [MW]	Load factor
Gas CCGT	High	910 €/kW + 49140209 €	5.0	1200	0.5
	Central	793 €/kW + 23205098 €		900	0.3
	Low	677 €/kW + 9555041 €		600	0.1
Gas CCGT w. post. Comb CCS	High	2009 €/kW + 49140209 €	2.8	1200	0.5
	Central	1658 €/kW + 23887601 €		900	0.3
	Low	1326 €/kW + 9555041 €		600	0.1
Gas OCGT	High	502 €/kW + 15151564 €	4.5	800	0.15
	Central	403 €/kW + 12353302 €		550	0.10
	Low	322€/kW + 955504 €		400	0.05

Table 21.Parameter values used in spreadsheet model for gas fired technologies. Source: Parsons Brinckerhoff [24].

	Operational lifetime [years]	Average availability [%]	Net lhv efficiency [%]	CO_2 removal [%]
Gas CCGT	35	93	58.5	
Gas CCGT w. post comb. CCS	35	93	51	90
Gas OCGT	35	93	39	

Coal fired technology

Table 22. Parameter values (high, central, low) used in spreadsheet model for coal fired technologies. Source: Parsons Brinckerhoff [24]. Capacities and load factors has been chosen by the author.

	Level	Cost of investment	Yearly fixed cost [% of investment]	Capacity	Load factor
Coal ASC w post comb. CCS	High	2009 €/kW + 49140209 €	2.85	1800	0.5
	Central	1658 €/kW + 23887601 €		1600	0.3
	Low	3052 €/kW		1200	0.1
Coal ASC w. oxy comb CCS	High	4584 €/kW + 20475087 €	2.85	1200	0.5
	Central	3306 €/kW + 10237543 €		900	0.3
	Low	1988 €/kW		600	0.1
Coal IGCC w. CSS	High	2853 €/kW	5.0	1200	0.5
	Central	2045 €/kW		900	0.3
	Low	1235 €/kW		600	0.1

Table 23. Parameter values used in spreadsheet model for coal fired technologies. Source: Parsons Brinckerhoff [24].

	Lifetime [years]	Availability [%]	Net lhv efficiency [%]	CO_2 removal [%]
Coal ASC w. post comb. CCS	25	95	35	90
Coal ASC w. oxy comb. CCS	30	95	35	90
Coal IGCC w. CCS	25	95	35	90

Nuclear Power technology

Table 24. Parameter values (high, central, low) used in spreadsheet model for nuclear power. Source: Parsons Brinckerhoff [24]. Capacities and load factors have been chosen by the author.

	Level	Cost of investment	Yearly cost of investment [% of investment]	Capacity [MW]	Load factor	Fuel price [€/MWh]	Decommi-ssioning [M€]
Nuclear	High	5938 €/kW + 31395133 €	2.0	4500	0.5	7-13	350
	Central	5387 €/kW + 15697567 €		3300	0.3		
	Low	4765 €/kW		1200	0.1		

Table 25. Parameter values used in spread sheet model for nuclear power.

	Operational lifetime	Average availability [%]	Net lhv efficiency
Nuclear	60	91	1

For nuclear technologies, fuel prices are quoted per unit of electrical energy output. In this situation, the efficiency is not required to calculate the fuel consumed. Therefore, no nuclear plant efficiency assumption has been provided. Rather, to be consistent with the fuel prices, the net lhv efficiency is set to be 100 per cent.

Hydropower and PSHP

To announce Norway's ability to serve Europe as a green battery in the LCOE studies, costs will be given specifically for the Norwegian conditions. Additionally, this study contains information about how the country can participate as a flexible source and back up for an energy demanding Europe. Due to this, the cost analysis is also taking into account the investment of cross boarder intersection with the continent. This is only the case for Norwegian hydropower and PSHP. The reason is that one may take the assumption that a gas, coal or nuclear power plant can, in theory, be build wherever in Europe without any extra large transmission and grid related costs.

As mentioned, the investment of hydropower and PSHP projects are collected from NVE and Vattenfall Power Consultant. For hydropower, an investment cost between 2.5 NOK/kWh and 4.5 NOK/kWh have been used as a basis, transferring to cost NOK/MW based on information from NVE.

For PSHP systems, Vattenfall Power Consultant suggests a price range from 434 €/MW to 992 €/MW for PSHP with high capacities. With an additional 1.6 per cent to assure cost of insurance and UoS charges, the prices ranging from 466 €/MW to 1024 €/MW. As earlier stated, the costs for PSHP is based on upgrades of existing hydropower plants, meaning investing in pumping facilities and additional waterway with larger dimensions than the original.

For yearly fixed cost, Parsons Brinckerhoff operates with 1.8 per cent of investment in their LCOE study from 2011 on PSHP [27]. Due to larger investment cost in their study, the percentage is raised to 2.2 per cent of the lower cost of investment used from NVE.

Table 26. Parameter values used in spreadsheet model for PSHP and hydropower. Source: NVE, Vattenfall Consultant [28]. Capacities and load factors has been chosen by the author.

	Level	Cost of investment [€/kW]	Yearly fixed cost [% of investment]	Capacity [MW]	Load factor	Availability	Efficiency [%]	Lifetime [years]
Pumped Storage Hydro-power	High	1024	2.20	1600	0.3	50%× 97.5%*	93	40
	Central	652		1200	0.2			
	Low	466		800	0.1			
Hydro-power	High	2262.4	2.20	1600	0.5	95%	93	40
	Central	1754.6		1200	0.3			
	Low	1256.9		800	0.1			

** PSHP in turbine mode 50 per cent of the time.*

Table 27. Parameter values used in spread sheet model for pumping system in PSHP. Capacities and load factors has been chosen by the author.

	Level	Cost of pumping per year [€/MWh]	Efficiency [%]	Load factor	Availability
Pumping system	High	40	80	0.3	50%× 97.5%*
	Central	30		0.2	
	Low	20		0.1	

** PSHP in pump mode 50 per cent of the time.*

Table 28. Costs in spreadsheet model for cable and grid upgrades. Source: Statnett [16].

	Investment cost, cable (Germany) [M€]	Reinvestment 20 years, cable (Germany) [M€]	Fixed yearly costs, cable (Germany) [M€]	Cost of grid upgrades [M€]
Additional costs	764.0	9.8	16.2	242.5

5 Results

This chapter presents the results from the various case studies completed using the spreadsheet model. Each case study represents individual parameter values chosen, and the studies are named as follows

1. Case Study 1 – Base Case Result
2. Case Study 2 – Load Factor
3. Case Study 3 – Discount Rate
4. Case Study 4 – Investment
5. Case Study 5 – Investment And Capacity
6. Case Study 6 – Optimistic Case And Pessimistic Case
7. Case Study 7 – Fuel And Pumping Price
8. Case Study 8 - Split Cost Of Cable And Grid Upgrades

The parameter values are stated in each case study, before each case study result is given.

5.1 Case Study 1 – Base Case Result

The LCOE with various load factors (high, central, low) presented in previous chapter are given here with fixed capacity, investment and pumping price (all central). Discount rate is 4 per cent.

Case Study 1 – Base Case Result shows how the result varies between the different load factors chosen. It gives insight to the load factor interval between 0.1 and 0.5.

Figure 9 gives the Base Case Result for 450 Scenario. All results from all three scenarios are given in Table 29. In Table 29, the PSHP are also listed with the additional (whole) cost of cable and grid upgrades.

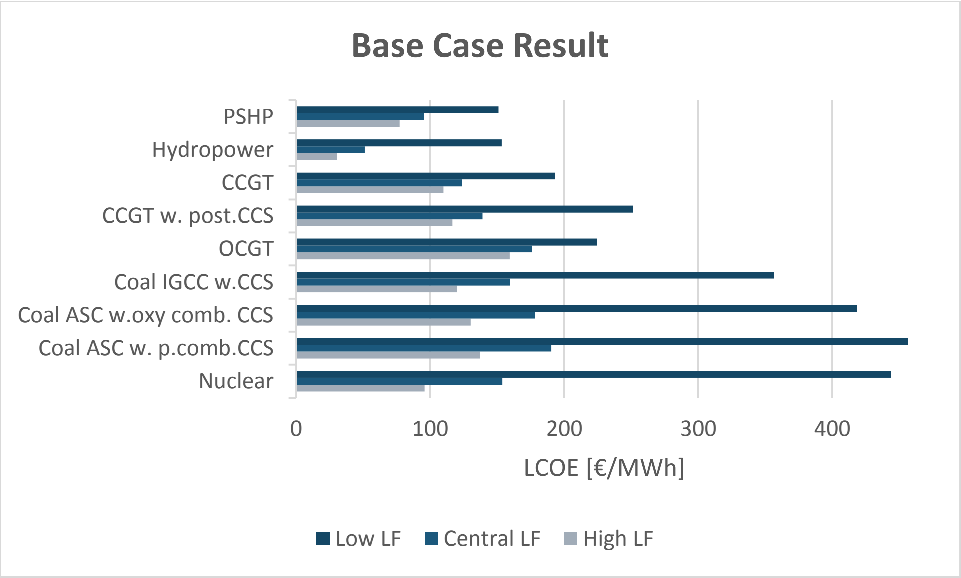

Figure 9. LCOE - Base Case Result.

Table 29. Results – LCOE w. high, central and low load factor.

	PSHP	Hydro power	Nucle ar	Scenario	CCGT	CCGT p.CCS	OCGT	Coal ASC p. comb. CCS	Coal ASC o. comb. CCS	Coal IGCC CCS
Load factor	**0.3**	**0.5**	**0.5**		**0.5**	**0.5**	**0.15**	**0.5**	**0.5**	**0.5**
High load factor	77.2	30.7	95.8	*450*	109.9	116.5	159.4	137.1	130.1	120.1
	113.1 *			*Current Policies Sc.*	108.6	137.7	157.6	145.4	146.6	128.9
	121.0 **			*New Policies Sc.*	104.9	131.1	152.3	151.8	135.6	125.9
Load factor	**0.2**	**0.3**	**0.3**		**0.3**	**0.3**	**0.1**	**0.3**	**0.3**	**0.3**
Central load factor	95.7	51.1	153.8	*450*	123.8	139.0	175.7	190.4	178.1	159.5
	149.4 *			*Current Policies Sc.*	122.5	160.2	173.9	198.7	197.4	168.3
	161.4 **			*New Policies Sc.*	118.8	153.6	168.6	208.4	183.6	165.3
Load factor	**0.1**	**0.1**	**0.1**		**0.1**	**0.1**	**0.05**	**0.1**	**0.1**	**0.1**
Low load factor	151.0	153.4	443.7	*450*	193.2	251.4	224.6	456.6	418.3	356.7
	258.5 *			*Current Policies Sc.*	191.9	272.7	222.7	465.0	451.4	365.5
	282.4 **			*New Policies Sc.*	188.2	266.0	217.5	491.7	423.8	362.5

**PSHP including total cost of cable. **PSHP including total costs of cable and grid upgrades.*

For OCGT the low load factor is 0.05, while the other load factors have been chosen to be 0.1. Still, one can see that OCGT can be compared to other conventional technologies under these given circumstances given. For information, the result from the spreadsheet model shows that OCGT is a better economical option than CCGT when both technologies are run with a load factor of 0.05. This will be further investigated in the next case study.

One interesting finding are that even with low load factor, PSHP is a better economical option than the other technologies presented. When including cost of cable and costs of both cable and grid upgrades, still it is competitive to, and in some cases a better option, when comparing it to the cost of conventional technologies like coal and gas fired alternatives.

It turns out that Current Policies Scenario are leading to the highest level of LCOE for all technologies with CCS. 450 Scenario gives at all times the lowest LCOE for the same alternatives. Remember, the 450 Scenario predicts a high carbon tax rate, while Current Policies Scenario is based on high fossil fuel prices and lower carbon tax rates.

5.2 Case Study 2 – Load Factor

In the following, the LCOE for each individual technology is plotted as a function of load factor.

The other parameters (capacity, investment and price of pumping) are set to their respective central values given. PSHP's (absolute) maximum load factor is here 0.4.

Each of the WEO 2014 scenarios, Current Policies Scenario, New Policies Scenario and 450 Scenario, are presented below in three different graphs.

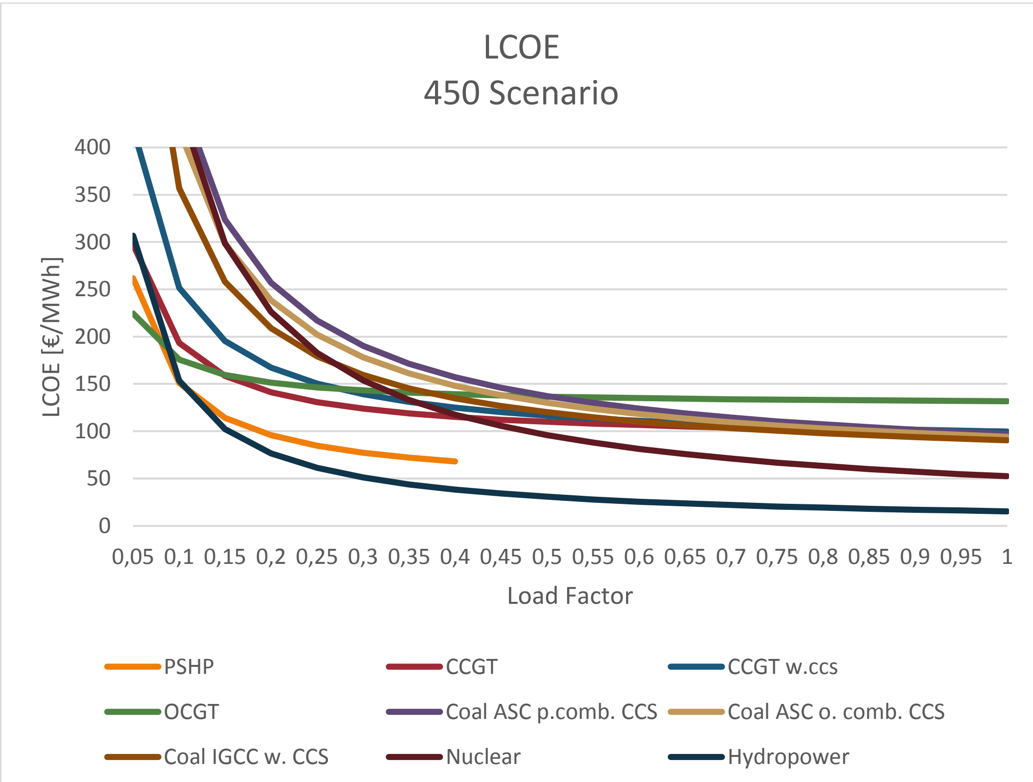

Figure 10. Result: LCOE - 450 Scenario.

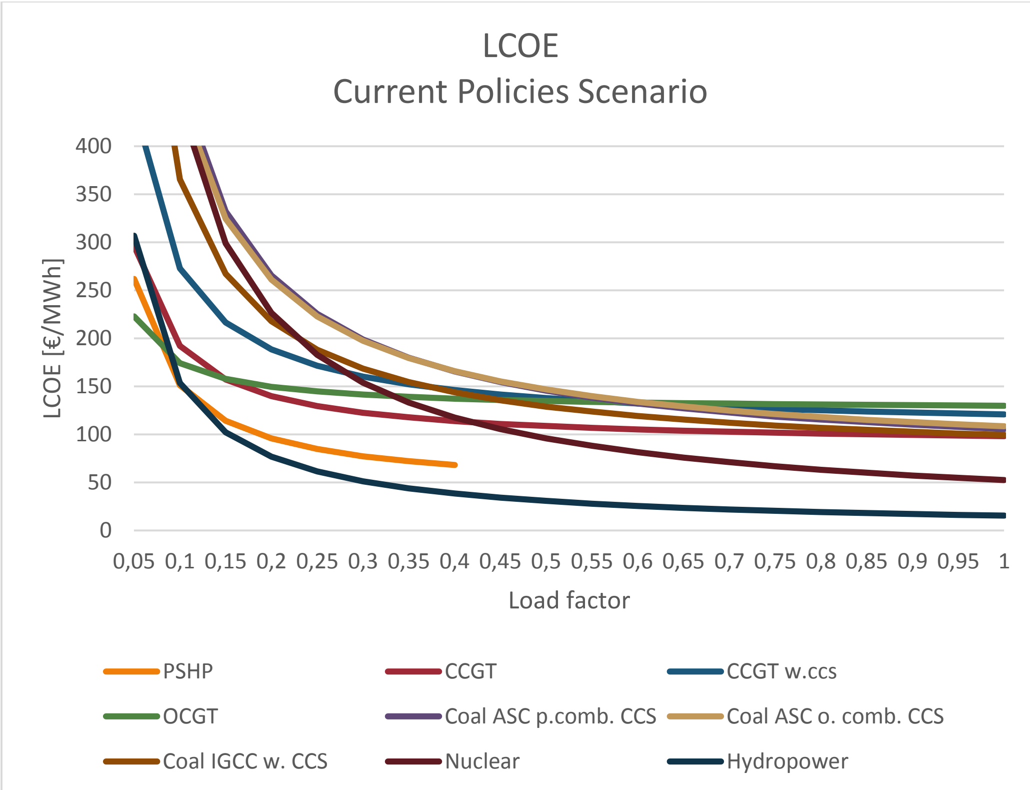

Figure 11. Result: LCOE - Current Policies Scenario

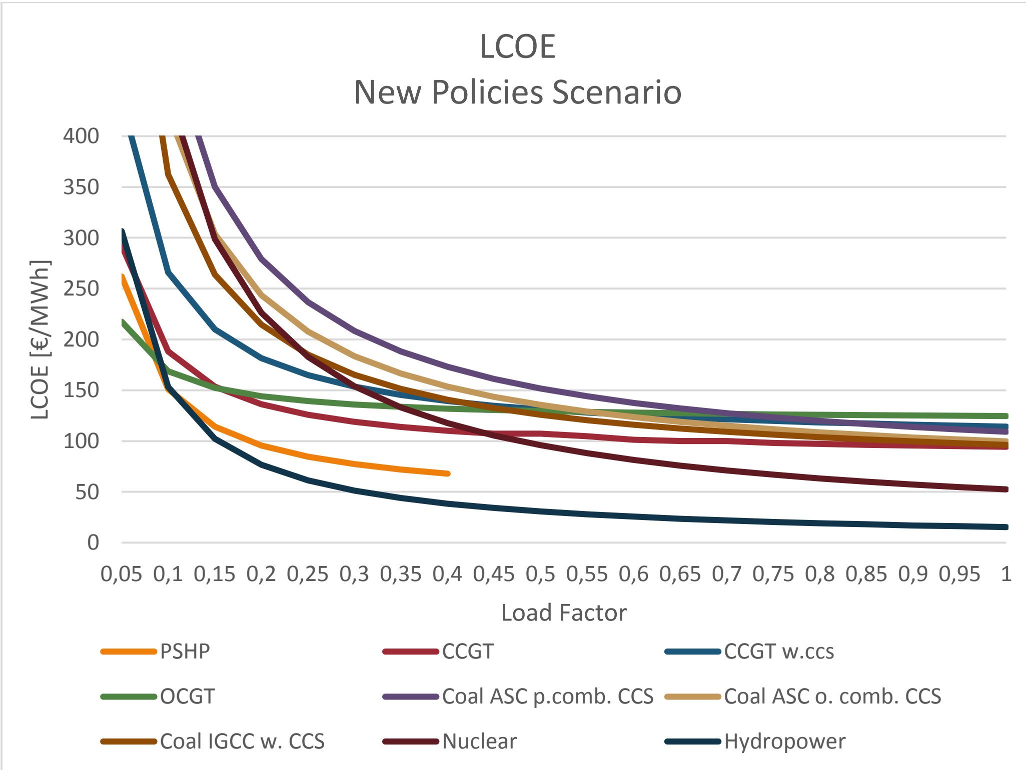

Figure 12. Result: LCOE - New Policies Scenario.

The figures shows a decreasing LCOE due to raise in load factor for all technologies. One can see from each scenario that hydropower definitely turns out to offer the lowest LCOE with high load factor. Nuclear are also showing a good trend towards low LCOE with high load factor. The PSHP's LCOE are lower than CCGT at all times, and also lower than OCGT when the load factor is higher than 0.1.

When load factor decreases and becomes between 0 and 0.1 one can see that OCGT has the lowest LCOE through all three scenarios. On the other hand, the curve for OCGT gives the highest LCOE with higher load factor.

The coal fired technologies does not give any good results. Future fuel and carbon costs will obviously lead to an increase in LCOE, which makes it less competitive against other base load alternatives like nuclear and hydropower. When load factor decreases and becomes lower than 0.3, levelized cost of coal fired and nuclear power technologies evens out and becomes inn the same cost range.

The most interesting LCOE values are when load factors are between 0 and 0.5, which may be the future use of flexible power plants like the ones compared in this study.

5.3 Case study 3 - Discount rate

Table 30 shows the result of the various LCOE depending on discount rate. Capacity, investment and load factor are fixed at their respective central values.

Table 30. Results – LCOE [2014€/MWh] with 4 % and 10 % discount rate.

<table>
<tr><th></th><th>PSHP</th><th>Hydro power</th><th>Nucle ar</th><th>Scenario</th><th>CCGT</th><th>CCGT p.CCS</th><th>OCGT</th><th>Coal ASC p. comb. CCS</th><th>Coal ASC o. comb. CCS</th><th>Coal IGCC CCS</th></tr>
<tr><td rowspan="3">4 % Discount Rate</td><td>95.7</td><td rowspan="3">51.1</td><td rowspan="3">153.8</td><td>450S Sc.</td><td>123.8</td><td>139.0</td><td>175.7</td><td>190.4</td><td>178.1</td><td>159.5</td></tr>
<tr><td>149.4 *</td><td>Current Policies Sc.</td><td>122.5</td><td>160.2</td><td>173.9</td><td>198.7</td><td>197.4</td><td>168.3</td></tr>
<tr><td>161.4 **</td><td>New Policies Sc.</td><td>118.8</td><td>153.6</td><td>168.6</td><td>208.4</td><td>183.6</td><td>165.3</td></tr>
<tr><td rowspan="3">10 % Discount Rate</td><td>135.2</td><td rowspan="3">87.6</td><td rowspan="3">279.3</td><td>450 Sc.</td><td>135.1</td><td>174.7</td><td>183.9</td><td>245.5</td><td>233.6</td><td>198.7</td></tr>
<tr><td>227.4 *</td><td>Current Policies Sc.</td><td>135.1</td><td>191.3</td><td>183.9</td><td>253.2</td><td>267.0</td><td>207.2</td></tr>
<tr><td>251.6 **</td><td>New Policies Sc.</td><td>131.8</td><td>185.7</td><td>179.5</td><td>278.3</td><td>238.8</td><td>204.4</td></tr>
</table>

**PSHP including total cost of cable. **PSHP including total cost of cable and grid upgrades.*

Levelized costs are sensitive to the level of discount rate. Especially hydropower and nuclear shows a large increase in LCOE, with a raise of 71.4 per cent and 81.6 per cent when comparing the discount rates of 4 and 10 per cent.

Gas fired technology seems to be less affected by the increased discount rate. The PSHP's LCOE increases more, and when adding the cost of cable and grid upgrades, it appears LCOE increases significantly due to increase of investment. It is worth to notice that with a 10 per cent discount rate, both PSHP and CCGT becomes 135 €/MWh. Here, it is important to be aware of the difference in central load factor values, which is 0.3 for CCGT and 0.2 for PSHP. Notice the high levelized costs of coal fired technologies.

5.4 CASE STUDY 4 - INVESTMENT

Table 31 shows the result of LCOE when various investment costs are used in the model. Load factor, capacities and pumping price are all fixed at their respective central values. Discount rate is 4 per cent.

Table 31. Results - LCOE [2014€/MWh] w. high, central and low investment costs.

	PSHP	Hydro power	Nuclear	Scenario	CCGT	CCGT p.CCS	OCGT	Coal ASC p. comb. CCS	Coal ASC o. comb. CCS	Coal IGCC CCS
High investment cost	127.3	65.7	168.7	*450*	130.0	151.6	187.7	217.4	207.9	198.4
	181.0 *			*Current Policies Sc.*	128.7	172.9	185.8	225.7	228.9	207.3
	193.0 **			*New Policies Sc.*	125.0	166.2	180.6	237.2	213.4	204.3
Central investment cost	95.7	51.1	153.8	*450*	123.8	139.0	175.7	190.4	166.5	159.5
	149.4 *			*Current Policies Sc.*	122.5	160.2	173.9	198.7	185.1	168.3
	161.4 **			*New Policies Sc.*	118.8	153.6	168.6	208.4	172.0	165.3
Low investment cost	79.9	36.5	137.0	*450*	118.2	127.4	165.8	163.5	123.8	120.5
	133.6 **			*Current Policies Sc.*	116.9	148.6	164.0	171.9	139.9	129.3
	145.6 **			*New Policies Sc.*	113.2	141.9	158.7	179.9	129.3	126.3

**PSHP including total cost of cable. **PSHP including total cost of cable and grid upgrades.*

The results shows that the technologies with relatively high investment cost compared to yearly expenses, like nuclear and hydropower, are more affected to the variations of investment cost level. The fossil fuel burning plants are not being affected to the same degree.

5.5 Case Study 5 – Investment And Capacity

Case Study 5 introduces how a power plants' high capacity in combination with low investment cost can be compared against a plant's low capacity and high investment cost. The LCOE is calculated with a load factor of 0.3 for all power plant technologies and a discount rate of 4 per cent.

Table 32. Result - LCOE [2014€/MWh] w. investment cost and capacity combination.

	PSHP	**Hydro power**	**Nuclear**	**Scenario**	**CCGT**	**CCGT p.CCS**	**OCGT**	**Coal ASC p. comb. CCS**	**Coal ASC o. comb. CCS**	**Coal IGCC CCS**
Low invest High capacty	66.7	36.5	136.9	*450S Sc.*	118.1	127.3	139.6	163.5	123.6	120.5
	93.6 *			*Current Policies Sc.*	116.8	148.5	137.8	171.9	139.7	129.3
	99.5 **			*New Policies Sc.*	113.1	141.9	132.5	179.9	129.1	126.3
High invest Low capacity	135.2	65.7	169.5	*450 Sc.*	131.1	152.5	147.5	217.6	207.9	198.4
	227.4 *			*Current Policies Sc.*	129.8	173.8	145.7	225.9	228.9	207.3
	251.6 **			*New Policies Sc.*	126.1	167.1	140.4	237.3	213.4	204.3

**PSHP including total cost of cable. **PSHP including total cost of cable and grid upgrades.*

Again, the LCOE for the alternatives related to hydro resources are remarkably lower than fossil fuel burning facilities in the combination of low investment and high capacity. In this case, nuclear power shows a relatively high LCOE. This comes from the chosen load factor of 0.3. Load factor 0.3 is a low load factor for nuclear power generation.

PSHP and hydropower are clearly sensitive to the change of investment and capacity. For example, a closer look at the levelized cost for PSHP, cable and grid upgrades, LCOE reaches 251.6 €/MWh! Hence, to invest in small PSHP facilities with relatively high cost of investment will not be an economical attractive option. Especially if Norwegian PSHP shall take into account the whole cost Statnett has estimated for the international cable connection to Germany and necessary national grid upgrades.

Notice that also in this situation, gas fired technologies are not as sensitive to the mentioned changes as hydropower and PSHP.

5.6 Case Study 6 – Optimistic Case And Pessimistic Case

Case Study 6 introduces how the LCOE changes depending on a set of optimistic parameter values compared to a set of pessimistic values. With the following assumptions given in Table 33, an Optimistic Case and a Pessimistic Case are presented in Figure 13.

Table 33. Parameter values for Optimistic Case and Pessimistic Case.

	Investment	Capacity	Load factor	Price for pumping	Fuel price	Carbon tax
Optimistic	*Low values*	*Central values*	*0.6 (0.35 for PSHP)*	*Low [20 €/MWh]*	*450 Scenario*	*450 Scenario*
Pessimistic	*High values*	*Central values*	*0.2*	*High [40 €/MWh]*	*450 Scenario*	*450 Scenario*

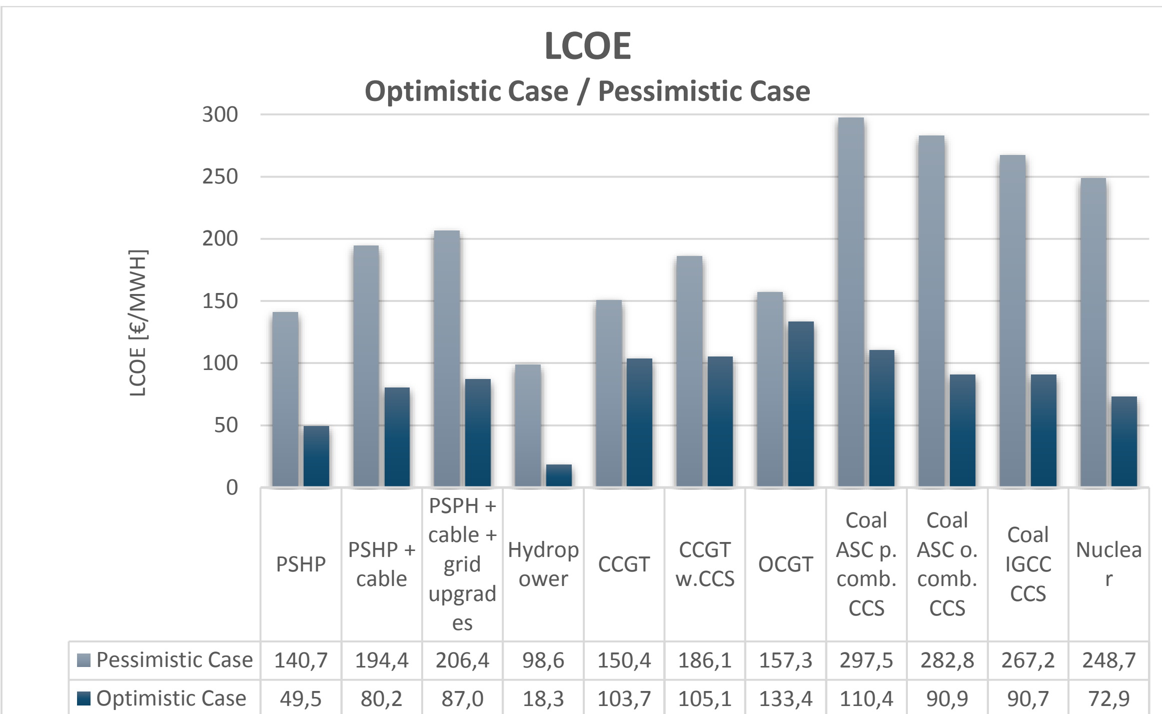

Figure 13. Results: LCOE for Optimistic Case and Pessimistic Case.

Here, there are several interesting findings. The first observation worth mentioning are the LCOE values from the optimistic case. Hydropower distinguish from all other alternatives, with a LCOE of 18.3 €/MWh. Further, PSHP and nuclear gives also relatively low LCOE. Actually, PSHP and its additional costs of cable and grid upgrades actually has a lower LCOE than all alternatives based on fossil fuel.

Additionally, Figure 13 shows how the individual LCOE can differ based on parameter values. One observation is the large difference between the alternatives with a relatively high investment cost difference. When load factor is low, this is affecting LCOE tremendously. This yields especially for nuclear. Nonetheless, PSHP and hydropower is showing a large difference in LCOE depending on optimistic values or pessimistic numbers. Another observation is the low difference between LCOE for gas fired technologies. For CCGT the difference between optimistic case and pessimistic case is "only" 45 per cent. For PSHP, LCOE is actually 2.8 times higher with pessimistic values compared to optimistic values! For hydropower, it is actually 5.4 times higher! Having said that, the mentioned “pessimistic” LCOE for hydropower and PSHP, excluding cost of cable and grid upgrades, are still lower than CCGT’s “pessimistic” LCOE.

5.7 Case Study 7 – Fuel And Pumping Prices

For a closer comparison between the most interesting familiar alternatives for flexible generation, the graphs in Figure 14, Figure 15 and Figure 16 shows how the LCOE curves interferes depending on fuel price and pumping price.

In the high fuel and pumping price scenario the Current Policies Scenario are used together with a pumping price of 40 €/MWh. The prices in New Policies Scenario are compared to a pumping price of 30 €/MWh while in the low fuel and pumping price scenario, 450 Scenario are measured against a pumping price of 20 €/MWh. All results are at a discount rate level of 4 per cent.

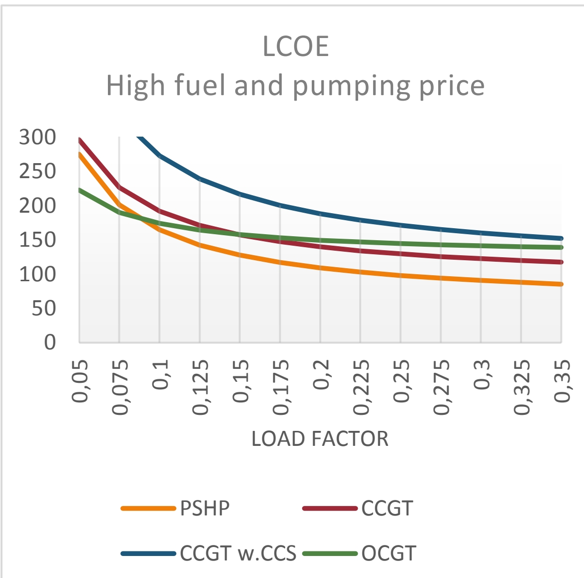

Figure 15. LCOE High fuel and pumping price.

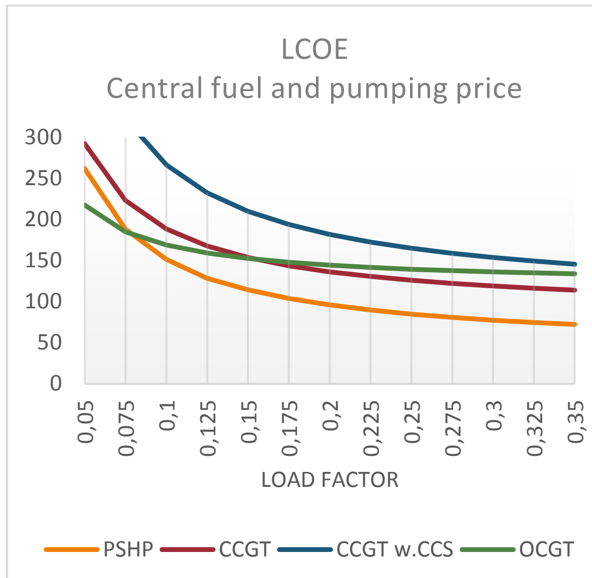

Figure 14. LCOE Central fuel and pumping price.

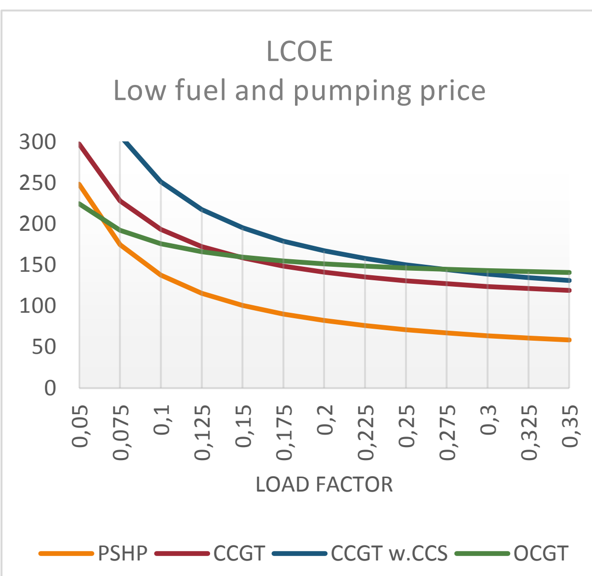

Figure 16. LCOE Low fuel and pumping price.

One important measure is LCOE for PSHP systems are at all times lower than CCGT, both with and without CCS. OCGT seems to offer the lowest LCOE at high price level beneath load factor of 0.08. At lower price scenario PSHP's LCOE are lower than OCGT's LCOE until load factor decreases beneath 0.065.

Notice that with central fuel prices, and a typically load factor of 0.3 the result shown in Figure 14 will be a good alternative for comparison, which may reflect upon how PSHP and CCGT are, and most likely will be, run. To include numeric results, LCOE results are given in Table 34.

The table below shows that CCGT's LCOE is 54 per cent higher than LCOE for PSHP. CCGT with CCS has close to twice as high levelized costs as PSHP, while LCOE for OCGT are 76 per cent higher.

If total cost of cable was to be included, the LCOE for PSHP becomes 113.1 €/MWh, while including in addition grid upgrades the cost reaches 121.0 €/MWh.

Table 34. LCOE - Load factor 0.3 and central fuel and pumping price.

	PSHP	CCGT	CCGT w. CCS	OCGT
LCOE [€/MWh]	77.2	118.8	153.6	136.0

5.8 Case Study 8 – Split Cost Of Cable And Grid Upgrades

In Case Study 8, it is assumed split costs of cable between Statnett and TenneT. This is supposed to reflect the most likely cost distribution for the Nord.Link project. This means that the LCOE for Norwegian hydropower and PSHP includes here these mentioned cost, while gas fired power plants can in theory be placed wherever without any significant extra cost for transmission upgrades. Figure 17 is showing how the cost of cable and grid upgrades are affecting the LCOE for hydropower and PSHP, and it is compared to the most flexible sources. Capacity and investment are at their respective central values. Load factor is 0.3 for all alternatives except OCGT, which is run with load factor 0.1. Discount rate is 4 per cent.

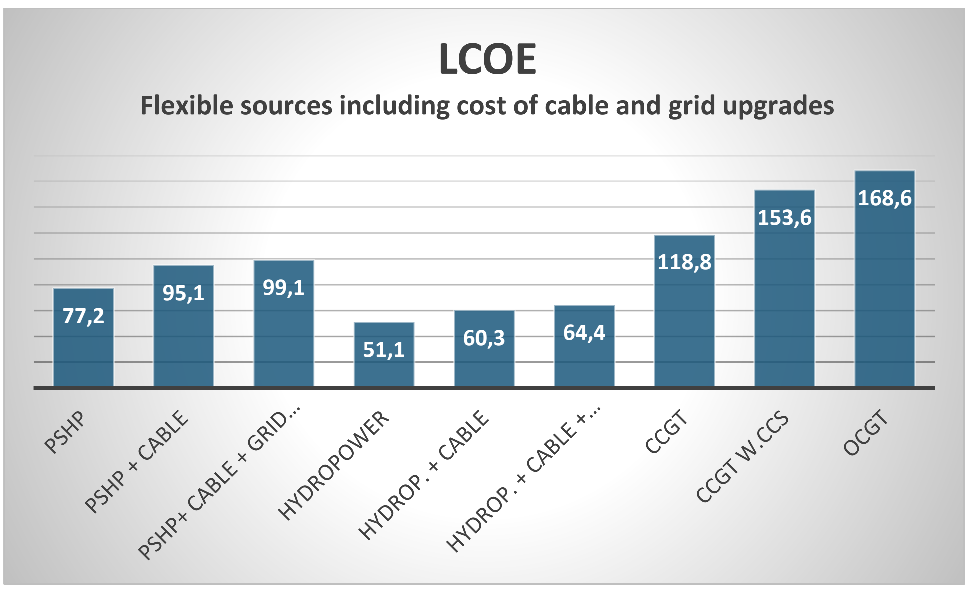

Figure 17. LCOE for flexible sources, including split cost of cable and grid upgrades [€/kWh].

The result is not to be mistaken. Hydropower and PSHP gives lower LCOE than CCGT, CCGT with CCS and OCGT. This statement is regardless if cost of cable and grid upgrades are included in the calculation or not.

6 Discussion

6.1 LCOE

Clearly, methodologies for calculating LCOE can distinguish a lot to one another.

Obviously, capital cost/investment must be included, where contingency cost, EPC costs, owners costs and land cost is normal to include. Further, fixed and variable O&M costs are a large part of the cost for several technologies, especially for coal and gas fired technologies, which must account for cost of fuel and carbon taxes. Still, there are some differences between the levels these costs are in. Of course, it is hard to predict future prices, but most authors assumes a price raise for fuel and carbon releases. This makes the LCOE more realistic, and cost scenarios are often collected from authorities that are specialists in this field. If one where not to include a price raise, the investors will most likely get an expensive unpredicted experience.

NVE have used 4 per cent discount rate in their cost study, which is why this also yields in this LCOE study. The LCOE is extremely sensitive to discount rate, and 10 per cent is supposed to make the calculation risk neutral. Therefore, generally, 10 per cent is used by sources that are analyzed in this report, but some sources have also several case studies with 5 per cent.

For external cost, there is not always market integration costs included in the cost methodology, but if they are, they are not so different from one to another. Hence, these costs do not contribute to any large differences between the various alternatives.

When the power plants are site specific, the task becomes much more comprehensive. It will of course have some impact where the plant is build. Like Norwegian hydropower, where the circumstances are much better for plant development compared to less suited areas elsewhere. Costs may differ to a large extent, and highly effect the LCOE.

Most authors does not include the costs of transmission upgrades. Some authors refers to integration cost when discussing this topic. Cost of upgrades of these kinds can actually become a large share of the cost picture for some technologies placed far away from the consumer. Especially is this something that appears in Europe nowadays, with an energy system penetrating more wind power and solar photovoltaics. These costs are not so high when only looking at conventional power plants. Therefore, including these costs, is will make a contribution to higher the LCOE for remote resources. A typically example is offshore wind power.

To add subsidies to renewable power production makes renewable alternatives more attractive to invest in. In spite of this, in later years the energy system all over the world will have a larger share of renewable resources in the system, which can lead to exclusion of subsidies of its art. Hence, for future prognoses, it is not optimal to calculate with the extra income. Actually, LCOE is based on costs, not income, and the subsidies should therefore be kept out of the LCOE calculation. It is rather beneficial to use the LCOE to find the level of subsidies and tax credits necessary to make renewable power production economic viable and comparable to conventional technologies.

Something that also may differ are if the costs are set as a yearly payment or one time investment. This can be related to connection and system charges and network and grid upgrades. One may include charges of network usage as a yearly payment, but others may not include it, or only taking into account as a one time cost.

Decommissioning are usually included, which justifies the large cost of especially nuclear disposal. These costs are very high compared to other plants decommissioning cost. Between the other technologies, the cost may not differ so much, but is important part of the levelized cost of nuclear power.

It is obvious that for LCOE calculation, there are many ways to proceed, and there are actually no specific right or wrong way to do it. For a third party authority, it is obvious that LCOE for dispatchable and intermittent resources must be separated in some way. Either they are distinguished with different capacity values, or it is reflected through lower load factors for intermittent RES than their dispatchable competitors. Often, the author specifically mentions that LCOE must not be the only foundation for decision making for an investment. It is a fact that authorities are able to *make* generating technologies more favourable. For instance, add subsidies to renewable generating technologies, exclude certain cost etc. Still, for the readers, investors or other decision makers that are familiar with LCOE calculation methodologies are most often aware of this and must be able to consider all external factors that affects an investment like the ones discussed here. LCOE serves as a good proxy, which helps policy makers, academics and others who needs benchmark for discussion.

6.2 LCOE RESULTS FROM CASE STUDIES

Cost inefficiency with lower load factor

Throughout this study it appears that higher investment cost technologies, such as nuclear and coal firing power plants, have a higher LCOE compared to the other power generation entities at lower load factors. As the load factor increases, the technologies becomes better economical options. Actually, at a load factor of 0.6, all of the three alternatives from coal firing technologies becomes competitive alternatives for power generation. This is shown in Case Study 6 and Figure 13. Furthermore, nuclear power is in fact a very good economical option for base load power generation and comes out as top three with lowest LCOE in the Optimistic Case. The economics of nuclear power generation only gets better (i.ea. lower LCOE) as the load factor increases. Hence, since coal fired and nuclear power plants usually cover a large percentage of base load generation today, the results seem overall logical.

Fuel prices and carbon taxes complementing each other in IEA scenarios.

An interesting discovery is how LCOE is affected by the various rise and decrease in fuel price and carbon taxes. The Current Policies Scenario is based on a high raise in fuel prices and lower increase of carbon taxes, while the 450 Scenario predicts lower fuel prices but higher carbon tax rates. It appears that the prices complements each other, which means that the LCOE for the Current Policies Scenario and the 450 Scenario actually turns out to not differ to such a large extent as it may seem when first introducing the variables.

Another finding is the difference between technologies with and without CCS. Technologies with 90 per cent CCS will obviously not be affected in the same way by an increased carbon tax rate. This is proved in several case studies presented in the previous chapter. LCOE for CCGT with CCS is more closely following the gas price development, since the cost of carbon taxes are almost excluded due to CCS. The order is as follows; Current Polices Scenario, New Policies Scenario, and then 450 Scenario. Results from OCGT and CCGT calculations have a smaller degree of fuel price dependency since carbon taxes makes each scenario result more equalized. It actually puts the prices in a different cost order. 450 Scenario gives the highest LCOE for OCGT and CCGT, which is the opposite result for CCGT with CCS.

Norwegian hydropower and PSHP - good economical and flexible options.

With an increased share of renewables, the energy system needs flexible units that can offer security of supply. Norwegian hydropower and PSHP has the opportunity to not only participate in Norway and Scandinavia, but now, with more cross border intersections, also in the European continent. Scandinavian countries can contribute as a storage platform for European energy usage.

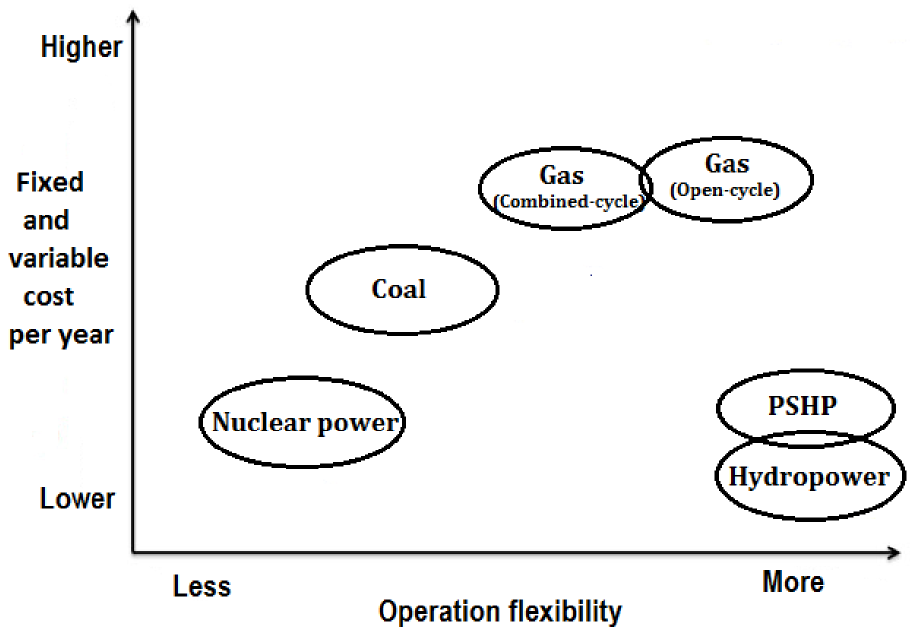

Figure 18. The combination of operation flexibility and yearly cost for various technologies.

Hydropower and PSHP systems can offer quick start, load following, frequency regulation and black start capability. They are able to ensure safe and automatic generation control since the energy is only needed to be "set free". Non of the other alternatives in this study can offer the same amount or composition of benefits. A multifunctional technology like hydropower is indispensable to the European power system, and it will be even more important to the system tomorrow. For generating technologies, the most important for the overall system is its capability to cover fluctuations between consumption and supply. Hydropower already contributes as a balancing source. In the future, this will be even more appreciated and valuable. Now, luckily, attention has also risen towards value creation through PSHP facilities.

For PSHP, the load factor is limited to 0.40. However, after advices from experts, PSHP systems are most often not able to run at this level. The reason is the pumping system, as a consequence needs to operate at a load factor of 0.53 to account for losses. This again leads to a running of the plant relatively close to 100 per cent. This is far from the truth, and 35 per cent is therefore used in some case studies as a maximum. Even though, with a maximum load factor of 0.35, LCOE for PSHP turns out to be at the lower level compared to other conventional technologies. In a situation with a high pumping price (40 €/MWh) it still comes out as a better option than CCGT, both with and without CCS.

Energy storage through PSHP may reduce mechanical wear on other units and improve power factor for other generating power plants. This leads to reduction of losses. At the same time, if PSHP systems offers load following, it will lead to other units reaching higher individual efficiencies. Other generating power plants will be able to operate at a specific point where a higher efficiency is obtained. Another benefit may be longer operational lifetime for these other types of generating units.

One major development incentive for PSHP are the increased demand for peak power in liberalized Europe markets. Peaking units like gas fired power plants have often been the main source to cover peaking hours. With PSHP it will be possible, not to eliminate gas power peaking plants, but to reduce the usage of these. Less greenhouse gas pollution will be one major benefit.

Costs of cable and grid upgrades

From another point of view, including all costs of the Nord.Link project, which is Statnett's and TenneT's newly invested cable connection between Norway and Germany, the cost picture obviously changes for the PSHP alternative. When looking at the Optimistic Case and the Pessimistic Case, it turns out that the total cost becomes extremely high in the Pessimistic Case, and the PSHP's LCOE turns out to be 37.2 per cent higher than CCGT's LCOE, while it is 32.2 per cent higher than LCOE for OCGT. In spite of the large costs of cable and grid upgrades, the LCOE for PSHP in the Optimistic Case actually turns out to be lower than all the alternatives based on gas burning technology. Load factor for PSHP is here set to its practical maximum of 0.35, while the other technologies' LCOE have been calculated with a load factor of 0.6. This is an interesting discovery, which definitely gives additional credits to the investment of Norwegian PSHP.

Furthermore, looking at a divided cost distribution of the cable investment, the calculation shows a LCOE for PSHP, cable and grid upgrades of 99 €/MWh. CCGT's LCOE is 119 €/MWh, CCGT w. CCS 154 €/MWh and finally 169 €/MWh for OCGT's LCOE. This is the most likely cost distribution for the cable connection, and it is clear that even with transmission costs included for the PSHP system, it gives lower levelized costs than its competitors.

Discount rate

It is no secret that levelized cost are highly sensitive to the underlying discount rate. A good example was given in Case Study 3. The large investment of nuclear and hydropower makes those two alternatives less favourable in the example with 10 per cent rate. The PSHP system is less sensitive with the lower investment cost. Nonetheless, when adding the cost of cable and grid upgrades, the internal changes become bigger.

Furthermore, only looking at the LCOE for PSHP compared to CCGT, the high discount rate still does not make the CCGT a more favourable option than PSHP. Both alternatives end up with LCOE at 135 €/MWh.

PSHP and hydropower sensitive to operations circumstances and investment

Several case studies shows a large variation of LCOE for PSHP and hydropower. Gas fired technologies seems to be less influenced by the parameter variations. This is related to the fact that gas fired technology is highly dependent on fossil fuel prices and carbon taxes. The prices in the three IEA scenarios used in this study complements each other, which makes the variations of LCOE for CCGT and OCGT power plants relatively small. They are less sensitive to the cost of investment.

The findings in Case study 5 was unambiguous. Here, a combination of investment and capacity was presented. It was clear that for an investor to invest in small PSHP facilities and in addition cover cost of transmission and grid upgrades can not be justified. At least not from an economical point of view. It means that if Norwegian PSHP should take the whole cost of the international transmission connection and national necessary grid upgrades alone, there must be a specific size of the plant, and also, it must be placed somewhere with satisfactory conditions so that the project becomes cheaper. Analogously, economic viable.

However, adding the mentioned costs to only one PSHP system alone will to some extent be wrong. When the cable is operational, and if PSHP technology is proved the investment worthy, the cost may, in theory, be split between several PSHP units. This means a lower LCOE for each PSHP facility.

In addition, the operational lifetime of a hydropower plant or a PSHP is in the calculation set to 40 years [21], while several other sources claims an operational lifetime of 60 years, perhaps with some necessary upgrades. If the study had accounted for 20 more years, the levelized cost would have been even lower than what is presented here.

Peaking power from gas technology

The curve for OCGT gives the highest LCOE with higher load factor. This should not be a surprise since OCGT is the most familiar peaking plant used in the power system. This means that the plant is often run with a low load factor and few operational hours during the year. This makes sense to all the results given, which points out a lower LCOE with low load factor compared to other technologies. At which load factor level it offers the lowest LCOE is depending on a lot of factors and circumstances such as fossil fuel prices and energy price for pumping. Still, at a load factor lower than 0.1 OCGT seems to be a good economical option for generation.

For future environmental sustainability

A worldwide rise in energy demand forces the governments to think ahead. Together with the increased renewable energy supply requirements, Norwegian PSHP seems to be an excellent contribution. This statement can be justified from several holds. Firstly, from an economical point of view because of findings in this report. Secondly, due to the need of increased peak power generation and thirdly, because of the needed raise of renewable share in the European energy mix. Eurelectric claims that hydropower is the backbone of a reliable renewable electricity system. Further, the PSHP can contribute as a similar resource.

Higher LCOE than other studies

The readers that are familiar with LCOE studies might be sceptical to the high cost level given in the result. It is important to be aware of the fact that this study includes the change in fuel market and the other formalities and changes that will come from facing future environmental challenges. For instance, rise in fuel price, carbon tax and energy price for pumping are all included in this study, and it might be different compared to other LCOE calculations. Furthermore, a lower load factor than normal is used in some of the case studies due to the increasing amount of renewable generation in the European power system. This will of course give much higher LCOE for the conventional base load power plants.

Moreover, the cost of investment in Norwegian hydropower facilities may differ to other studies in the international energy business. The reason for this statement is the favourable site conditions and rich hydro resources located in this country. In other areas the situation is different, with smaller mountains and perhaps unqualified geotechnical conditions. Preparing for artificial magazines and lower capacity obtained in the plant gives higher capital costs and less salary compared to the Norwegian investors. The study used in this report is based on the cost of upgrading already existing hydropower facilities in Norway. Obviously, this makes the investment cost lower than building of new power plants.

Actually, the investment cost of PSHP from NVE has been compared to the cost presented in Parsons Brinckerhoff. With a recommended capacity in Parsons Brinckerhoff of 400 MW, load factor of 0.4 (!) and pumping price of 30 €/MWh, the LCOE becomes 142.7 €/MWh. The investment cost here was 2551 €/kW while the corresponding investment with Norwegian circumstances is 652 €/kW. The LCOE result with numbers from NVE for a typically PSHP capacity of 1200 MW and load factor of 0.3 becomes approximately 80 €/MWh .

To summarize, Norway is in the lucky situation of accessible conditions for hydropower and PSHP usage, ensuring clean, reliable, secure and affordable energy. Hydropower is already well known in the Scandinavian energy supply system, but the condition for PSHP is still not utilized as much as it could be. However, looking into future energy development in Europe, Norwegian PSHP most certainly will be requested abroad.

Extra costs that were not included

Costs that could have been added to this study could have been additional costs of fossil fuel transportation, costs of efficiency loss due to degradation of power plants, and also the costs of start ups and ranking down. This was chosen not to be implemented in the calculation, but it is something to be aware of. It will raise the LCOE some more. Actually, costs of fossil fuel transportation and mechanical wear due to hurry start ups are mostly related to the fuel using plants. PSHP and hydropower have the opportunity to easily “let energy free” to start the machinery or increase the power generation. This is not possible with the other alternatives.

Furthermore, still only looking into Norwegian conditions, if the various hydropower plants were to be upgraded, it would be even “cheaper” to invest in PSHP. My point is, when upgrading a power plant, spending resources, and considering power plant shut down and loss of income, the investment of PSHP in that specific power plant may not be so much higher than the plant upgrade itself.

Political and regulatory uncertainty

For PSHP development, there is need for political and regulatory decision makers to make a statement. Statnett, with their cable connection investment, seems to add favorable conditions for power exchange across country boarders, leading to less volatile electricity prices. To also offer enough flexible generation and other valuable advantages to the power system, there is need for more engagement. There is no doubt that the future European energy mix, with more wind power and solar photovoltaics, will need secure back up resources and supplying load following generation. When the RES are producing more than the users consumes, PSHP will be a good way to store the overshare of energy. It is one of the essential roles of PSHP in centralized market contexts. The policy makers should make generation available for upcoming years. It is clearly beneficial to be a nation who fronts a commitment like this. Even better, it is proved during this LCOE study several times that PSHP is a cheaper solution than many of its competitors, even though one must be aware of the various circumstances that may not have been evaluated. Also, to take into account the higher risk of investing in PSHP than the conventional CCGT, who seems not to have such fluctuation in costs. Clearly, it is still some work left to do before making the decisions of the huge investments related to the discussed topic. First, the framework conditions for investors and plant developers must become predictable, and secondly, Norwegian hydropower and PSHP needs full access to the European power markets. Another important additional factor is that EU continuously needs to work towards the climate goals that are already set, which the politicians should take seriously. Nonetheless, the Europeans seeks a rise of flexible generation and renewable energy production, and PSHP is a great contributor to both. Unfortunately, there is currently a lack of ambition from the key persons and investors.

7 CONCLUSION

LCOE is a convenient type of measurement that summarizes the overall competitiveness of several different generating technologies. There are several ways to calculate LCOE, and there is no typically no wright or wrong way to proceed. Some may argue that when intermittent and dispatchable power productions are compared to each other, LCOE may to some be a misleading metric. The reason for this is the large variations in production profile and the difference in the market value of the supplied energy. Still, the energy business is familiar with this, and investigators often compensate for this by capacity values or specifically distinguish between the dispatchable and non dispatchable technologies. Overall, LCOE is a good benchmark for discussion, and it is one of several ways to analyze a project's feasibility and compare it to other alternatives.

The best alternatives for flexible generation comes from hydropower, PSHP and gas fired power plants. Coal fired power plants and nuclear power seems not to deliver the flexibility that is necessary. In addition, they are also less cost efficient when a lower load factor situation might be the future of conventional technologies.

Norwegian hydropower and PSHP gives, in most cases, the lowest levelized cost of generating electricity. OCGT can offer the lowest LCOE at load factor under 0.08, depending on parameter variables. For a closer comparison between some of the most flexible sources, a case study with a load factor of typically 0.3 and central values for pumping price, capacities and investment cost shows a LCOE of 51.1 for hydropower, 77.2 €/MWh for PSHP, 118.8 €/MWh for CCGT, 153.6 €/MWh for CCGT with CCS and finally 168.6 €/MWh for OCGT's LCOE. These are remarkable differences. However, including all costs of cable and grid upgrades on the Norwegian side, i.e. adding them to the PSHP alternative, the levelized cost for PSHP equals 121.0 €/MWh, which then reaches the same cost level as CCGT.

The costs differ to some extent when PSHP's LCOE only accounts for a share of the cable connection costs. When dividing the cost Statnett has estimated for the Nord.Link project between the investors on both sides (Norway and Germany), and further adding the costs of necessary grid upgrades, the LCOE becomes 64.4 €/MWh for hydropower and 99.1 €/MWh for PSHP. The Norwegian conditions for PSHP and hydropower seems to be the best option from an economical point of view, even though it has to include more cost of transmission and distribution upgrades compared to the other flexible options in this study.

PSHP and hydropower proves to be sensitive to parameter values and discount rate. Hence, when parameter values reflect a relatively good case for the various technologies, PSHP outperforms other candidates. On the other hand, when cost of investment rises together with a higher price for pumping, the LCOE for PSHP increases significantly. Especially compared to gas fired technologies, which is more dependent of fuel prices and carbon taxes. However, PSHP still comes out with the lowest LCOE, but the cost is more equalized to cost of other technologies such as CCGT. From this, one can make the conclusion that it will be of a higher risk to invest in PSHP than gas fired technology. Still, the winnings can be tremendously large.

Europe’s electricity landscape is, and will be, going through profound changes, due to the aim of an energy sector containing more renewables and lower carbon facilities. Consequently, for the future European power system, it is important to be aware of the fact that no single “fits all solution” exists, and it is therefore important to do research and investigate the various energy situations and various conditions existing. Nonetheless, this study shows that the Norwegian conditions, the upcoming raise in energy demand and the need of flexible and “green” electricity generation makes PSHP investment an attractive choice. PSHP’s LCOE is definitely among the lower, only beaten by Norwegian hydropower. The results are promising, but there are consequences due to the sensitivity to various parameters. I strongly recommend the PSHP alternative as flexible back up generation and solution to facilitate the integration of large share of RES in upcoming years. Together with the already existing hydropower facilities in Norway, the country has the ability to become the green battery of Europe now with increased transmission connections cross country borders. The only thing keeping us from becoming it is the lack of political and regulatory willingness to take initiative and provide enough resources for the development.

8 Further work

In the author's opinion, recommendation for future work that would be of interest to deal with can be summarized as follows:

- To simulate the power market in the EMPS model, extracting optimal load factors PSHP systems.
- To be able to model a more accurate future electricity price for pumping. PSHP's LCOE are very sensitive to pumping price, and it will be preferable to do studies with a more precise price estimation.
- The North Sea Network project, meaning the cable connection towards UK, is scheduled operational in 2021. With large offshore wind projects in the North Sea, it is likely that also the Englishmen will need a higher share of flexible generation. How will this, in addition, affect the Norwegian PSHP's economic feasibility is also interesting and highly relevant for investors.
- To include other power generating entities, as for example biomass power, and other proven large scale storage technologies, like batteries and compressed air energy storage, in a cost model to compare them against PSHP will give further knowledge about PSHP's economical position.
- How PSHP systems will operate in liberalized electricity markets should be evaluated to achieve more insight to operational strategies for PSHP systems. Looking at ongoing PSHP projects, studies on flexible operation strategies can make the Norwegians operators secure an optimal running strategy and making it become mandatory.
- Develop the spreadsheet model or take the work further in another mode, making it more extensive. It is desired to make a more thoroughly model for LCOE calculations for general use.

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APPENDIX A

Spread Sheet Model – Manual and information

This manual and information is written for understanding for whomever would like to use the spread sheet model. The different sheets are explained, and some basic calculation information is given for the user to better understand how the model is working.

Parameter settings

The first page, "parameters settings" is the sheet where the user is able to change parameter values which affects the Levelized Cost of Electricity (LCOE).

The discount rate is given at the top. The user can choose whatever discount rate that is preferable. Type the chosen discount rate in the yellow square in column B. Remember to distinguish between percentage and decimals. The user shall put the discount rate as a decimal value. Hence, 4 per cent equals 0,04.

The various technologies are all presented to the left side of the sheet. Under each technology, capacity, investment cost and load factor are parameters that can be altered in their coloured squares in column B.

In the middle of the page, the values of capacities, investment cost and load factor and price for pumping used in the case studies are given. High, central and low values are presented. These are only given to show in which range the cost are in this particularly study.

The user can use these numbers if it is desired, but are free to put in own values. (To justify the load factors given, the load factors reflects running of the plant as a "more flexible" unit than may be the situation today.) The numbers that are given in coloured squares are the numbers that corresponds with one of the named parameters in column A.

To use other parameter values, it is possible to type in investment cost, load factor, and price for pumping, if it is preferable. It is important that this is done in "Parameters settings" so the other sheets does not miss their basic codings. The user can type their parameter values in the coloured squared in column B.

To assure the user, the values with coloured background in column B are the values that can be altered to calculate new LCOE.

The LCOE is calculated and given below each technology category. For pumped hydro storage, LCOE is calculated for PHS alone, for PHS and total cost of cable (Nord.Link project), and at least for PHS including total cost of cable (Nord.Link) and estimated costs of related grid upgrades in Norway. For coal and gas technologies, LCOE is given for each scenario (450 , Current P.Sc and New P.Sc.)

LCOE overview

"LCOE overview" is the sheet that gives the summarized Levelized Cost of Electricity for each individual technology. Here, it is easy to get an overview over the result and compare the technologies levelized costs to each other.

The user is not supposed to make changes in this sheet.

Technology sheets

The next sheets are the calculations sheets, where the various costs is calculated automatically when the mentioned parameters in "Parameter settings" is changed. The values directly related to "Parameter settings" are coloured blue in column B. These are not to be altered in the individual calculation sheets.

In column B, some values are marked in red. These numbers shall not be altered. The numbers here are being calculated automatically due to established equations.

The squares with no coloured background (white), is for the user to change if he/she would like to decrease or increase the values. Still, the values in the sheets are recommended from the author from the basis of the related cost study.

Each sheet are linked to one technology. The costs are calculated at the lower part of the sheet. To the right, prices for coal, gas and carbon taxes are listed with the annotation [€/MWh – el] for the technologies where it is relevant. [€/MWh-el] only means that the prices are "ready" to multiplied directly with the amount of produced electricity. These values are especially for the given technology in this sheet. The reason is that the prices has accounted for efficiencies and carbon content etc., which makes the values individual.

General information

First, to avoid misunderstanding, when a percentage is applied in the model, 1 equals 100 per cent. The user shall use decimals. This accounts for discount rate, load factor, availability, efficiencies and fixed O&M. 4 per cent discount rate shall be typed 0,04 in the spread sheet model.

Furthermore, the following table will give some additional information about the model and reasons for some assumptions done:

Parameter information	***Information***
Fixed O&M costs	Given as percentage of investment cost.
Turbine mode (PSHP)	The mode where PHS operates as a generating unit.
Pump mode (PSHP)	The mode where PHS operates as a consuming unit.
Load Factor Pump	To cover efficiency losses in PSHP, the pump is assumed to be run with the following load factor: $Load\ factor = \frac{Load\ Factor\ turbine\ mode}{Efficiency\ Turbine\ mode \times Efficiency\ Pump\ mode}$
Decommissioning	Cost of decommissioning only taken into account for nuclear power.
Fossil fuel prices and carbon taxes	Individual calculations due to various net lhv efficiencies. The prices has not been calculated in the specific model. Information about the calculation are given in Appendix B, C, D and E.
Operational lifetime	There will be no consequences of changing the number of years in operation. The lifetimes are set due to the calculation method chosen.
Net lhv efficiency	Efficiency accounting for lower heating value. Accounts for the whole energy process, i.e. fuel burning to power output.
Nuclear net lhv efficiency	Because of the fuel cost given in per MWh generated, the net lhv efficiency for nuclear is set to 1 (100 %). It does not affect the other calculations.

To summarize

- In the sheet “Parameter settings”, coloured squares in column B can be altered.
- The sheet “LCOE overview” is just to summarize all LCOE results. Nothing should be changed, added or removed from this sheet.
- In the individual technology sheets, the user shall not change the values or equations in coloured squares in column B. The user can change the squares with no coloured background if it is desired.

Appendix B

Prices for fossil fuel - Natural gas

The IEA has estimated these future prices for Europe imports, announced through WEO 2014.

Scenario / year	2013	2020	2030	2040
450 Sc.	10.6	10.5	10.0	9.2
Current Policies Sc.	10.6	11.5	13.2	14.0
New Policies Sc.	10.6	11.1	12.1	12.7

The prices are real terms prices 2013, given in $/MBTU.

The gas prices are weighted averages expressed on a gross calorific-value basis (HHV).

When energy is given on a gross calorific value, most known as higher heating value, HHV, the energy is given after bringing all the products of combustion back to the original temperature (before combustion). HHV assumes therefore that all the water component is in liquid state at the end of combustion. This is not the case when burning fossil fuels, releasing the water content as wapor as unused heat content. Therefore, in such applications, one can assume that lower heating value,LHV, are the most correct value to use for the burning process.To distinguish between LHV and HHV this formula is used:

$HHV = LHV + h_v \times (n_{H2O,out}/n_{fuel,in})$
h_v = the heat of vaporization of water
$n_{H2O,out}$ = the number of moles of water vaporized
$n_{fuel,in}$ = the number of moles of fuel combusted

Without going in to further details on this formula, it concludes that for natural gas, HHV is 1.11 times LHV, or LHV is 90 per cent HHV. This is used in the calculation of LHV.

The result of the transformation are given below, taken an inflation rate of 2.3 per cent per year, and the energy transaction of 1 million BTU equals 0.293 MWh. The currency is assumed as given below.

LHV	0.9xHHV
1 MWh	3.413 MBTU
Inflation rate	2.3 %

Currency	Norwegian kroner (DnB)
1 USD $	7.61 NOK
1 GBP £	11.78 NOK
1 Euro €	8.63 NOK

Scenario / year	2013	2020	2030	2040
450 Sc.	36.26	35.92	34.21	31.47
Current Policies Sc.	36.26	39.34	45.16	47.89
New Policies Sc.	36.26	37.97	41.39	43.45

The prices are real terms prices 2014, €/MWh (lhv).

Result of interpolation:

Scenario / Year	450 Scenario	Current Policies Scenario	New Policies Scenario
	€/MWh lhv	€/MWh lhv	€/MWh lhv
2020	35.92	39.34	37.97
2021	35.75	39.92	38.31
2022	35.58	40.50	38.65
2023	35.41	41.08	38.99
2024	35.20	41.66	39.33
2025	35.07	42.24	39.67
2026	34.90	42.82	40.01
2027	34.73	43.40	40.35
2028	34.56	43.98	40.69
2029	34.39	44.56	41.03
2030	34.21	45.16	41.39
2031	33.94	45.43	41.60
2032	33.67	45.70	41.81
2033	33.40	45.97	42.02
2034	33.13	46.24	42.23
2035	32.86	46.51	42.44
2036	32.59	46.78	42.65
2037	32.32	47.05	42.86
2038	32.05	47.32	43.07
2039	31.78	47.59	43.28
2040	31.47	47.89	43.45
2041	31.20	48.16	43.66
2042	30.93	48.43	43.87
2043	30.66	48.70	44.08
2044	30.39	48.97	44.29
2045	30.12	49.24	44.50
2046	29.85	49.51	44.71
2047	29.58	49.78	44.92
2048	29.31	50.05	45.13
2049	29.04	50.32	45.34
2050	28.77	50.59	45.55
2051	28.50	50.86	45.76
2052	28.23	51.13	45.97
2053	27.96	51.40	46.18
2054	27.69	51.67	46.39

For further use, the net lhv efficiencies have been taken into account. Each gas fired technology has their individual efficiency. They have been used to calculate the cost of fuel per MWh electricity generated. The efficiencies are from Parsons Brinckerhoff [24].

	Net lhv efficiency [%]
Gas CCGT	58.5
Gas CCGT w. post comb. CCS	51.0
Gas OCGT	39.0

By dividing the gas prices with the individual net lhv efficiencies of each gas fired technology, the final price for each generating unit are achieved. These numbers are implemented in the spread sheet model.

Appendix C

Prices for fossil fuel – Steamed coal

The IEA has estimated these future prices for Europe imports of steamed coal, announced through WEO 2014.

Scenario / year	2013	2020	2030	2040
450 Sc.	86	88	78	77
Current Policies Sc.	86	107	117	124
New Policies Sc.	86	101	108	112

The prices are real terms prices 2013, given in $/tonne.

For adjustment into right annotation, an energy content in steamed coal is set to 24 MJ/kg, which equals 6.67 MWh/tonne [22].

1 tonne coal	6.67 MWh term
Inflation rate	2.3 %

Currency	Norwegian kroner (DnB)
1 USD $	7.61 NOK
1 GBP £	11.78 NOK
1 Euro €	8.63 NOK

Scenario / year	2013	2020	2030	2040
450 Sc.	11.63	11.90	10.55	10.41
Current Policies Sc.	11.63	14.47	15.82	16.77
New Policies Sc.	11.63	13.66	14.61	15.15

The prices are real therms prices 2014, given in €/MWh.

Result of interpolation:

Scenario / Year	450 Scenario	Current Policies Scenario	New Policies Scenario
	€/MWh	€/MWh	€/MWh
2020	11.90	14.47	13.66
2021	11.76	14.61	13.75
2022	11.62	14.75	13.84
2023	11.48	14.89	13.93
2024	11.34	15.03	14.02
2025	11.20	15.17	14.11
2026	11.06	15.31	14.20
2027	10.92	15.45	14.29
2028	10.78	15.59	14.38
2029	10.64	15.73	14.47
2030	10.55	15.82	14.61
2031	10.54	15.92	14.66
2032	10.53	16.02	14.72
2033	10.51	16.11	14.77
2034	10.50	16.21	14.82
2035	10.49	16.30	14.88
2036	10.48	16.40	14.93
2037	10.46	16.50	14.99
2038	10.45	16.59	15.04
2039	10.44	16.69	15.09
2040	10.41	16.77	15.15
2041	10.40	16.87	15.20
2042	10.39	16.96	15.26
2043	10.37	17.06	15.31
2044	10.36	17.15	15.36
2045	10.35	17.25	15.42
2046	10.34	17.35	15.47
2047	10.32	17.44	15.53
2048	10.31	17.54	15.58
2049	10.30	17.63	15.63
2050	10.28	17.73	15.69
2051	10.27	17.83	15.74
2052	10.26	17.92	15.80
2053	10.24	18.02	15.85
2054	10.23	18.11	15.90

For further use, the net efficiencies are taken into account. It is assumedthat all coal fired technologies has the same net efficiency. It is used to calculate the cost of fuel per MWh electricity. The efficiency values are from Parsons Brinckerhoff [24].

	Net efficiency [%]
Coal ASC w. post comb. CCS	35
Coal ASC w. oxy comb. CCS	35
Coal IGCC w. CCS	35

Appendix D

Carbon content in fossil fuels and carbon taxes

The IEA has estimated these future prices for Europe imports of carbon taxes, announced through WEO 2014.

Scenario / year	2020	2030	2040
450 Sc.	22	100	140
Current Policies Sc.	20	30	40
New Policies Sc.	22	37	50

The prices are real terms prices 2013, given in $/tonne carbon.

Carbon content in natural gas and related costs of carbon releases

Information related to carbon content in various fuels are collected from U.S. Energi Information Administration [23]. Gross calorific value (HHV) is 0.185 kg carbon/kWh. Accounting for LHV, this equals 0.205 kg/kWh. The following values has been used for calculation:

1 MWh (generated from natural gas)	0.205 tonne CO_2
Inflation rate	2.3 %

Currency	Norwegian kroner (DnB)
1 USD $	7.61 NOK
1 GBP £	11.78 NOK
1 Euro €	8.63 NOK

Scenario / year	2020	2030	2040
450 Sc.	4.07	18.49	25.89
Current Policies Sc.	3.70	5.55	7.40
New Policies Sc.	4.07	6.84	9.25

The carbon taxes are real terms prices 2014, given in €/MWh(lhv).

As for fossil fuel prices, interpolation is used to get a price for each year.

Scenario / Year	450 Scenario	Current Policies Scenario	New Policies Scenario
	€/MWh (lhv)	€/MWh (lhv)	€/MWh (lhv)
2020	4.07	3.70	4.07
2021	5.51	3.89	4.35
2022	6.95	4.08	4.63
2023	8.39	4.27	4.91
2024	9.83	4.46	5.19
2025	11.27	4.65	5.47
2026	12.71	4.84	5.75
2027	14.15	5.03	6.03
2028	15.59	5.22	6.31
2029	17.03	5.41	6.59
2030	18.49	5.55	6.84
2031	19.23	5.74	7.08
2032	19.97	5.93	7.32
2033	20.71	6.12	7.56
2034	21.45	6.31	7.8
2035	22.19	6.5	8.04
2036	22.93	6.69	8.28
2037	23.67	6.88	8.52
2038	24.41	7.07	8.76
2039	25.15	7.26	9
2040	25.89	7.40	9.25
2041	26.63	7.59	9.49
2042	27.37	7.78	9.73
2043	28.11	7.97	9.97
2044	28.85	8.16	10.21
2045	29.59	8.35	10.45
2046	30.33	8.54	10.69
2047	31.07	8.73	10.93
2048	31.81	8.92	11.17
2049	32.55	9.11	11.41
2050	33.29	9.30	11.65
2051	34.03	9.49	11.89
2052	34.77	9.68	12.13
2053	35.51	9.87	12.37
2054	36.25	10.06	12.61

Due to the net lhv efficiency in the burning process, the emission per kWh produced electricity becomes higher. With individual efficiencies, the carbon taxes also becomes individual per MWh generated electricity. This is covered in the model. The efficiencies have been taken from Parsons Brinckerhoff [24].

Carbon content in steamed coal, and related costs of carbon releases

The carbon taxes from IEA have been used for steamed coal to calculate carbon taxes for usage in the spread sheet model. The following values has been used for calculation:

1 MWh (generated from steamed coal)	0.325 tonne CO_2
Inflation rate	2.3 %

Currency	Norwegian kroner (DnB)
1 USD $	7.61 NOK
1 GBP £	11.78 NOK
1 Euro €	8.63 NOK

Scenario / year	2020	2030	2040
450 Sc.	6.45	29.32	41.05
Current Policies Sc.	5.86	8.80	11.73
New Policies Sc.	6.45	10.85	14.66

The carbon taxes are real terms prices 2014, given in €/MWh.

Result after interpolation:

Scenario / Year	450 Scenario	Current Policies Scenario	New Policies Scenario
	€/Mwh	€/Mwh	€/Mwh
2020	6.45	5.86	6.45
2021	8.74	6.15	6.89
2022	10.98	6.44	7.33
2023	13.22	6.73	7.77
2024	15.46	7.02	8.21
2025	17.70	7.31	8.65
2026	19.94	7.60	9.09
2027	22.18	7.89	9.53
2028	24.42	8.18	9.97
2029	26.66	8.47	10.41
2030	29.32	8.80	10.85
2031	30.49	9.09	11.23
2032	31.66	9.38	11.61
2033	32.83	9.67	11.99
2034	34.00	9.97	12.37
2035	35.17	10.26	12.75
2036	36.34	10.55	13.13
2037	37.51	10.85	13.52
2038	38.68	11.14	13.90
2039	39.85	11.43	14.28
2040	41.05	11.73	14.66
2041	42.22	12.02	15.04
2042	43.39	12.31	15.42
2043	44.56	12.61	15.80
2044	45.73	12.90	16.18
2045	46.90	13.19	16.56
2046	48.07	13.49	16.94
2047	49.24	13.78	17.33
2048	50.41	14.07	17.71
2049	51.58	14.36	18.09

For further use, the net efficiencies has been taken into account. Coal fired power plants have all the same net efficiency, and it is being accounted for this in the spread sheet model. The efficiencies have been taken from Parsons Brinckerhoff [24].

Appendix E

Cost of carbon capture and storage (CCS)

Parsons Brinckerhoff assumes a cost of CO_2 capture and storage cost of 19.6 £/ tonne [24].

Fossil fuel	CCS Price [€/tonne]	CO_2 content [tonne/MWh]	Net lhv efficiency [%]	Cost CCS [€/MWh]
Gas (CCGT w.CCS)	26.8	0.205	35	15.70
Coal (all types)	26.8	0.325	35	24.89

The information related to carbon dioxide content in gas and coal are from Energy Information Administration [23].

The cost of CCS are assumed identical through the whole operational lifetime of the plant.